STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company : 23-0068

Proposed general increase in rates and revisions to service classifications, riders and terms and conditions of service. (tariff filed January 6, 2023)

The Peoples Gas Light and Coke Company : 23-0069

Proposed general increase in rates and revisions to service classifications, riders and terms and conditions of service. (Cons.) (tariff filed January 6, 2023)

ORDER

November 16, 2023
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ORDER

By the Commission:

I. INTRODUCTION

A. Procedural History

On January 6, 2023, North Shore Gas Company (“North Shore” or “NS”) filed with the Illinois Commerce Commission (“Commission” or “ICC”), pursuant to Section 9-201 of the Public Utilities Act (the “Act”), 220 ILCS 5/9-201, the following revised tariff sheets from NS’s Schedule of Rates for Gas Service (ILL. C.C. No. 17): Fifteenth Revised Sheet No. 6; Sixteenth Revised Sheet No. 8; Sixteenth Revised Sheet No. 10; Eighth Revised Sheet No. 12; Twenty-first Revised Sheet No. 27; Twelfth Revised Sheet No. 58; Ninth Revised Sheet No. 76; Tenth Revised Sheet No. 77; Eighth Revised Sheet No. 78; Tenth Revised Sheet No. 85; Ninth Revised Sheet No. 86; Twenty-first Revised Sheet No. 124; and Eighth Revised Sheet No. 135.1. This tariff filing embodied a proposed general increase in gas service rates and included revisions to the service classifications, riders, and terms and conditions of service, to be effective February 20, 2023. The tariff filing was accompanied by direct testimony, exhibits, and other materials required under Parts 285 and 286 of Title 83 of the Illinois Administrative Code (the “Code”), 83 Ill. Adm. Code 285 and 286.

On January 6, 2023, The Peoples Gas Light and Coke Company (“Peoples Gas” or “PGL”) filed with the Commission, pursuant to Section 9-201 of the Act, 220 ILCS 5/9-201, the following revised tariff sheets from PGL’s Schedule of Rates for Gas Service (ILL. C.C. No. 28): Sixth Revised Sheet No. 2; Thirteenth Revised Sheet No. 5; Fourteenth Revised Sheet No. 7; Fourteenth Revised Sheet No. 9; Seventh Revised
Sheet No. 11; Fourteenth Revised Sheet No. 16; Twenty-first Revised Sheet No. 28; Twentieth Revised Sheet No. 29; Third Revised Sheet No. 30; Ninth Revised Sheet No. 31; Third Revised Sheet No. 31.1; Second Revised Sheet No. 31.2; Eleventh Revised Sheet No. 59; Eighth Revised Sheet No. 77; Ninth Revised Sheet No. 78; Eighth Revised Sheet No. 79; Sixth Revised Sheet No. 86; Eighth Revised Sheet No. 87; Twenty-third Revised Sheet No. 139; Nineteenth Revised Sheet No. 140; Tenth Revised Sheet No. 142; Ninth Revised Sheet No. 143; Ninth Revised Sheet No. 144; Ninth Revised Sheet No. 145; Tenth Revised Sheet No. 146; Sixth Revised Sheet No. 151.1; Sixth Revised Sheet No. 164; and Fourth Revised Sheet No. 166. This tariff filing embodied a proposed general increase in gas service rates and included revisions to the service classifications, riders, and terms and conditions of service, to be effective February 20, 2023. The tariff filing was accompanied by direct testimony, exhibits, and other materials required under Parts 285 and 286 of the Code, 83 Ill. Adm. Code 285 and 286.

Notices of the proposed tariff changes reflected in these rate filings were posted in the business offices of North Shore and Peoples Gas (together, the “Companies”) and published in secular newspapers of general circulation in the Companies’ respective service areas, as evidenced by publishers’ certificates, in accordance with the requirements of Section 9-201(a) of the Act, 220 ILCS 5/9-201(a), and the provisions of Part 255 of the Code, 83 Ill. Adm. Code 255.

On January 19, 2023, the Commission issued a Suspension Order for North Shore’s tariff filing, which suspended the tariffs to and including June 4, 2023, and further initiated Docket No. 23-0068. On June 1, 2023, the Commission issued a Resuspension Order that suspended these tariffs to and including December 4, 2023.

On January 19, 2023, the Commission issued a Suspension Order for Peoples Gas’ tariff filing, which suspended the tariffs to and including June 4, 2023, and further initiated Docket No. 23-0069. On June 1, 2023, the Commission issued a Resuspension Order that suspended these tariffs to and including December 4, 2023.


Staff of the Commission (“Staff”) participated in this proceeding, and the Office of the Illinois Attorney General (the “AG”) and the City of Chicago (“COC” or the “City”) filed appearances. Petitions to intervene were filed on behalf of AARP, the Building Owners and Managers Association of Chicago (“BOMA/Chicago”), the Citizens Utility Board (“CUB”), Community Organizing and Family Issues (“COFI”), the Environmental Defense Fund (“EDF”), the Environmental Law and Policy Center (“ELPC”), Gas Workers Union Local 18007, Utility Workers Union of America, AFL-CIO (“Local 18007”), the Illinois State Public Interest Research Group, Inc. (“ILPIRG”), Legal Action Chicago (“LAC”), Local 2285, International Brotherhood of Electrical Workers (“Local 2285”), the Natural Resources Defense Fund (“NRDC”), the People for Community Recovery (“PCR”), and the Retail Energy Supply Association (“RESA”). No objections were raised to the petitions
to intervene, and the petitions to intervene were granted by a duly authorized Administrative Law Judge (“ALJ”) of the Commission.

Pursuant to notice given in accordance with the law and the rules and regulations of the Commission, a pre-hearing conference was held in both dockets before the ALJ via videoconference on February 22, 2023. The ALJ orally granted the Companies’ Motion to Consolidate the dockets and approved a case schedule and data request response time schedule.

On March 8, 2023, the ALJ issued a ruling granting the Companies’ Motions for Protective Orders.

On April 17, 2023, the Commission issued a series of questions to the Companies (“Commissioners’ Questions”). The Companies submitted responses to the Commissioners’ Questions on May 16, 2023, as well as a Revised Response to Commissioners’ Question 1.02 NS on May 18, 2023. On May 30, 2023, the following parties submitted Replies to the Companies’ Responses to the Commissioners’ Questions: Staff; ELPC, EDF, NRDC, and ILRIRG (collectively, the “Public Interest Organizations” (“PIO”)); the City; the AG; and COFI and LAC, jointly.

On May 18, 2023, the AG filed a Verified Motion for Leave to File Instanter the Direct Testimony of Mary Selvaggio which was granted Nunc Pro Tunc by the ALJ on September 19, 2023.

On May 31, 2023, AARP filed a Motion for Local Public Hearings, which was granted by the ALJ on June 21, 2023. A local public hearing was convened at the University of Illinois-Chicago in Chicago, Illinois on August 1, 2023.

On August 4, 2023, Staff filed a Motion to Strike Portions of the Companies’ Surrebuttal Testimony of Joseph Zgonc. On August 8, 2023, the Companies filed a Response to Staff’s Motion to Strike.

On August 9, 2023, a status hearing was convened before the ALJ. At the hearing, the ALJ orally granted Staff’s Motion to Strike Portions of the Companies’ Surrebuttal Testimony of Joseph Zgonc.

On August 10, 2023, an evidentiary hearing was convened. The evidence admitted into the record included direct, rebuttal, surrebuttal, and revised testimony of the same, as well as cross-exhibits. The record was marked “Heard and Taken” on September 19, 2023.

The following witnesses testified on behalf of the Companies: Theodore Eidukas, Vice President – Regulatory Affairs at WEC Energy Group (“WEC”) (NS Ex. 1.0 REV, PGL Ex. 1.0 REV, NS-PGL Exs. 12.0 REV, 23.0-23.04, and 47.0); Joseph Zgonc, Manager – Financial and Regulatory Planning at WEC Business Services (“WBS”) (NS Exs. 2.0 REV, 2.1, 2.2 REV, 2.3-2.6, PGL Exs. 2.0 REV, 2.1, 2.2 REV, 2.3-2.7, NS-PGL Exs. 13.0-13.08, 24.0 REV02, 24.01P REV, 24.01N, 24.02-24.03, 24.04 REV, 48.0); Polly Eldringhoff, Vice President – Operational Performance and Compliance for North Shore and Peoples Gas (NS Exs. 3.0 REV, 3.1-3.8, PGL Exs. 3.0 REV CORR, 3.1-3.12, NS-PGL Exs. 14.0-14.05, 25.0-25.02, 35.0); Ann Bulkley, Principal at The Brattle Group (NS Exs. 4.0 REV, 4.1-4.10, 4.11 REV, 4.12, PGL Exs. 4.0 REV, 4.1-4.9, 4.10 REV, 4.11, NS-PGL Exs. 15.0-15.06, 26.0-26.01, 36.0); Jared Peccarelli, Manager – Sales Forecasting
for WBS (NS Exs. 5.0 REV, PGL Ex. 5.0 REV, NS-PGL Exs. 37.0); Aaron Nelson, Sr. Project Specialist – State Regulatory Affairs for WBS (NS Exs. 6.0 REV, 6.1-6.9, PGL Exs. 6.0 REV, 6.1-6.9, NS-PGL Exs. 16.0, 27.0, 38.0); Debra Egelhoff, Manager – State Regulatory Compliance & Advocacy for WBS (NS Exs. 7.0 REV, 7.1-7.8, 7.9 REV, PGL Exs. 7.0 REV, 7.1-7.4, 7.5 REV, 7.6-7.9, NS-PGL Exs. 17.0 REV, 17.1-17.3. 28.0-28.2, 49.0); Eric Nicolaus, Tax Manager – Regulatory for WEC (NS Ex. 8.0 REV, PGL Ex. 8.0 REV, NS-PGL Ex. 39.0); John Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC (NS Exs. 9.0 REV, 9.1, PGL Exs. 9.0 REV, 9.1, NS-PGL Ex. 40.0); Samuel Addison, Project Specialist 3 – State Regulatory at WBS (NS Exs. 10.0 REV, 10.1-10.2, PGL Exs. 10.0 REV, 10.1-10.2, NS-PGL Exs. 18.0-18.2, 29.0 REV, 29.1-29.2, 41.0); Jeffrey Westrick, Asset Manager at WBS (PGL Exs. 11.0 REV, 11.1-11.5, NS-PGL Ex. 42.0); Alan Weber, Area Manager – Field Operations for Peoples Gas (NS-PGL Exs. 19.0-19.04, 30.0, 43.0); David Baron, Director – Credit and Collections – Strategy and Operations for WBS (NS-PGL Exs. 20.0, 31.0, 44.0); Eric Olsen, Manager – Compensation for WEC (NS-PGL Exs. 21.0, 32.0-32.01, 45.0); and Frank Graves, Principal at The Brattle Group (NS-PGL Exs. 22.0-22.01, 33.0, 46.0). Koby Bailey, Senior Corporate Counsel – Regulatory Affairs for WEC submitted a verification on behalf of the Companies pursuant to Section 288.30(e) of the Code, 83 Ill. Adm. Code 288.30(e).

The following witnesses testified on behalf of Staff: Tonny Mugera, Accountant in the Accounting Department of the Financial Analysis Division (Staff Exs. 1.0, with Schedules (“Schs.”) 1.01N & P, 1.02N & P, 1.03N & P, 1.04N & P, 1.05N & P, 1.06N & P, 1.07N & P, 1.08N & P, 1.09P and Attachments (“Attachs.”) A and B, 9.0, with Schs. 9.01N & P, 9.02N & P, 9.03N & P, 9.04N & P, 9.05N & P, 9.06N & P, 9.07N & P, 9.08N & P, 9.09N & P, 9.10P and Attach. A, 9.1); Michael Alan, Accountant in the Accounting Department of the Financial Analysis Division (Staff Ex. 2.0, with Schs. 2.01N & P, 2.02P, 2.03N & P, and Attachs. A-F); Sheena Kight-Garlisch, Senior Financial Analyst in the Finance Department of the Financial Analysis Division (Staff Exs. 3.0, with Schs. 3.01-3.07, 11.0, 11.1); Michael McNally, Senior Financial Analyst in the Finance Department of the Financial Analysis Division (Staff Exs. 4.0Cor, with Schs. 4.01N & P and 4.01N & P and Attach. A, 12.0, 12.1); Cheri Harden, Rate Analyst in the Rates Department of the Financial Analysis Division (Staff Exs. 5.0, with Attachs. A and B, 13.0, with Attach. A); Jake Moushon, Rates Analyst in the Rates Department of the Financial Analysis Division (Staff Exs. 6.0, with Attachs. 6.01-6.09, 14.0, with Attachs. 14.01-14.04, 14.1); Brett Seagle, Gas Engineer in the Gas Section of the Energy Engineering Program of the Safety and Reliability Division (Staff Exs. 7.0, with Attachs. A-H, 15.0, 15.1); Bill Daniel, Joint Utility Locating Information for Excavators (“JULIE”) Investigator in the One-Call Enforcement program (“OCE”) within the Safety and Reliability Division (Staff Exs. 8.0 REV, with Attachs. A & B, 16.0, 16.1); and Theresa Ebrey, Accountant in the Accounting Department of the Financial Analysis Division (Staff Exs. 10.0, with Schs. 10.01P, 10.02N & P, 10.03N & P and Attachs. A-H, 10.1).

The following witnesses testified on behalf of the AG: Mary Selvaggio, a consultant at MES Consulting LLC (AG Exs. 1.0-1.2, 5.0-5.02, 9.0); Dr. David Dismukes, consulting economist with the Acadian Consulting Group (AG Exs. 2.0-2.17, 6.0R, 6.01-6.11, 10.0); Rod Walker, CEO & President of Rod Walker & Associates (AG Exs. 3.0-3.18, 7.0-7.03, 11.0); and Brendan Larkin-Connolly, Director of Utility Regulation and Litigation at DH Infrastructure LLC (AG Exs. 4.0-4.02, 8.0-8.01, 12.0).
The following witnesses testified on behalf of the City: Dr. Sol Deleon, Principal Associate at Synapse Energy Economics (COC Exs. 1.0-1.10, 3.0-3.04, 5.0); and Karl Rabago, principal of Rabago Energy LLC (COC Exs. 2.0-2.11, 4.0-4.08, 6.0).

Adrian Duenas, Business Manager, testified on behalf of Local 18007.

The following witnesses testified on behalf of BOMA/Chicago: T.J. Brookover, Regional Manager at AmTrust Realty Corp. (BOMA/Chicago Exs. 1.0-1.4); and Mark Pruitt, Principal of The Power Bureau (BOMA/Chicago Exs. 2.0-2.10).

Christopher Walters, a consultant with the firm of Brubaker & Associates, Inc. (“BAI”) testified on behalf of CUB and PCR, jointly (CUB/PCR Exs. 1.0-1.15, 2.0, 3.0).

The following witnesses testified on behalf of CUB/PCR/COC, collectively: Michael Gorman, a consultant with the firm of BAI (CUB/PCR/COC Exs. 1.0-1.2, 3.0-3.1, 5.0); and James Leyko, a consultant with the firm of BAI (CUB/PCR/COC Exs. 2.0-2.2, 4.0, 6.0).

The following witnesses testified on behalf of EDF: Sylvia Taylor, retired State of Illinois and Cook County employee and Englewood resident (EDF Exs. 1.0, 3.0); and Cheryl Watson, founder and owner of Equitable Resilience & Sustainability, LLC, and Chatham resident (EDF Exs. 2.0, 4.0).

The following witnesses testified on behalf of PIO: Bradley Cebulko, Senior Manager at Strategen Consulting (PIO Exs. 1.0-1.2, 4.0-4.5, 8.0); Chris Neme, Co-founder and Principal of Energy Futures Group (PIO Exs. 2.0-2.1, 5.0, 9.0); Justin Schott, Director of the Energy Equity Project and Lecturer of Energy Justice, both through University of Michigan’s School for Environment and Sustainability (PIO Exs. 3.0-3.5, 6.0-6.1, 10.0); and Catherine Elder, leader of the energy economics practice at Aspen Environmental Group (PIO Exs. 7.0-7.2, 11.0).

Roger Colton, owner of Fisher Sheehan & Colton, testified on behalf of COFI and LAC, jointly (COFI/LAC Exs. 1.0 CORR, 2.0-2.1, 3.0).

RESA neither filed testimony nor otherwise participated in the proceeding. The Companies, Staff, and the following parties filed Initial Briefs on August 24, 2023: the AG; PIO; COFI/LAC; BOMA/Chicago; the City; CUB/PCR/COC; AARP; and ELPC. The City filed a Corrected Initial Brief on September 5, 2023. The Companies, Staff, and the following parties filed Reply Briefs on September 7, 2023: the AG; COFI/LAC; ELPC; PIO; the City; and CUB/PCR/COC.

On September 11, 2023, per the direction of the ALJ, the Companies filed a Draft Order and Staff, CUB/PCR/COC, BOMA/Chicago, COFI/LAC, the City, the AG, PIO, filed draft position statements. On September 12, 2023, the AG filed an errata and amended position statement.

A Proposed Order was issued on October 6, 2023. On October 20, 2023, the Companies, Staff, the AG, PIO, CUB/PCR/City, ELPC, and the City filed Briefs on Exceptions. COFI/LAC was granted an extension and filed its Brief on Exceptions on October 23, 2023. The AG, PIO, the City and COFI/LAC each requested oral argument in their respective Briefs on Exceptions. The Commission granted oral argument on October 25, 2023, and it was held on November 6, 2023. On October 27, 2023, Reply
Briefs on Exceptions were filed by the Companies, Staff, the AG, PIO, the City, CUB/PCR/City, ELPC, COFI/LAC, and AARP.

B. Nature of Operations

1. North Shore’s Operations

North Shore is a wholly-owned indirect subsidiary of WEC, and is engaged in the business of transporting, purchasing, distributing, and selling natural gas at retail to more than 160,000 residential, commercial, and industrial customers in Chicago’s northern suburbs. This service territory covers an area of about 275 square miles. NS owns approximately 2,350 miles of gas distribution mains and approximately 58 miles of gas transmission lines. While North Shore does not own any gas storage facilities, it does purchase storage services from Peoples Gas, pursuant to the Storage Services Agreement approved by the Commission in Docket No. 12-0381, and from two interstate pipelines under rate schedules approved by the Federal Energy Regulatory Commission (“FERC”). In addition, North Shore owns a propane-air facility used to meet peak loads. North Shore employs over 150 people, of which 76% are union employees and 32% are diverse. When using contractors to perform construction work, North Shore uses only union labor.

2. Peoples Gas’ Operations

Peoples Gas is a wholly-owned indirect subsidiary of WEC, and is engaged in the business of transporting, purchasing, storing, distributing, and selling natural gas at retail to over 873,000 residential, commercial, and industrial customers within the City of Chicago. This service territory covers an area of about 237 square miles. PGL owns over 4,600 miles of gas distribution mains and approximately 340 miles of gas transmission lines. Peoples Gas also owns a gas storage field, Manlove Field. Peoples Gas employs over 1,400 people, nearly all of whom work in the City of Chicago. Sixty-nine percent of Peoples Gas’ workforce is diverse, and 69% is unionized.

C. Legal Standard

1. Companies’ Position

The Companies state that the Commission must establish rates that are just and reasonable to the utility and its stockholders, as well as customers. 220 ILCS 5/9-201(c); Bus. & Prof’l People for Pub. Interest v. Ill. Commerce Comm’n, 146 Ill. 2d 175 at 208 (1991) (“BPI 1”). The Commission succinctly summarized the applicable legal standards in North Shore’s and Peoples Gas’ 2012 test year rate case:

“Under long established federal and Illinois constitutional law, and Illinois ratemaking law, a utility’s rates must be set so as to allow it the opportunity to obtain full recovery of its prudent and reasonable costs of service, including its costs of capital.”

North Shore Gas Co., … Docket Nos. 11-0280, 11- 0281 Cons. (Order Jan. 10, 2012) (“Peoples Gas 2011”) at 5. The legal standards governing a utility’s right to a fair and reasonable rate of return, in particular, are well-established and familiar. A public utility has a constitutional right to a return that is “reasonably sufficient to assure confidence in the
financial soundness of the utility and [is] adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."  *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm’n of the State of W. Virginia*, 262 U.S. 679, 693 (1923).

*N. Shore Gas Co. and Peoples Gas Light & Coke Co.,* Docket Nos. 12-0511/12-0512 (cons.), Order at 6–7 (June 18, 2013).

The Companies note that under Illinois law, a utility bears the burden of proof that its proposed rates are just and reasonable. *See* 220 ILCS 5/9-201(c). However, once a utility has made a *prima facie* showing that its costs and expenses incurred in providing service are prudent, the burden of going forward with the evidence shifts to parties wishing to challenge those costs to refute the *prima facie* showing by providing record evidence of the unreasonableness in the utility’s business decisions. *See* *Bus. & Prof'l People for Pub. Interest v. Ill. Commerce Comm’n*, 279 Ill. App. 3d 824, 829–830 (1st Dist. 1996) ("BPI 2"). Prudence is “the standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made.” *Ill. Power Co. v. Ill. Commerce Comm’n*, 382 Ill. App. 3d 195, 201 (3d Dist. 2008). Further, “[i]n determining whether a judgment was prudently made, only those facts available at the time judgment was exercised can be considered.” *Id.*

2. **Staff’s Position**

Staff recommends that the Commission apply a just and reasonable standard in this proceeding and not subject the Companies to a least cost standard as recommended by the AG and PIO. Staff states that this legal standard for approval of rates in this proceeding is set forth in Section 9-201 of the Act.

While the least cost standard is relevant in certain sections of the Act, for example in Section 8-406 (Certificates of Public Convenience and Necessity (“CPCNs”), the least cost standard is not set forth in Section 9-201 of the PUA. Staff adds that there is no requirement in that section that a utility perform a least cost analysis like is done under Section 8-406. In addition, Staff is not aware of any case law stating that in rate proceedings under Section 9-201, a utility must establish the rates are least cost or perform a least cost analysis.

3. **AG’s Position**

The AG argues that the Companies have failed to meet their statutory burden of proof. The AG states that it is a well-established principle of utility ratemaking that costs are only recoverable when the utility demonstrates they are reasonable and prudent. 220 ILCS 5/9-101; BPI 1 at 247. The AG notes that in a ratemaking docket such as this one, the Companies bear the burden of proof and must provide substantial evidence to prove that their costs and expenses are reasonable in amount and prudently incurred. *Id.* at 196. This means the Companies must meet their burden with “more than a mere scintilla” of evidence and while “it does not have to rise to the level of a preponderance of the evidence,” “[i]t is evidence that a reasoning mind would accept as sufficient to support a

It is the AG’s position that the Act also demands that the Commission approve “least-cost public utility services at prices which accurately reflect the long-term cost of such services and which are equitable to all citizens.” 220 ILCS 5/1-102 (emphases added). When expenses are incurred “to achieve goals that primarily benefit shareholders, then it is reasonable to require that shareholders bear the cost of that [expense].” *People ex rel. Madigan v. Ill. Commerce Comm’n*, 2011 IL App (1st) 100654, ¶54.

The AG argues that the Companies’ petition unlawfully seeks to raise rates without sufficient regard to least-cost and affordability and without plans that reflect accurate long-term costs—all to the detriment of the state’s residents.

4. City’s Position

The City argues that the Commission must ensure that PGL’s rates are just and reasonable. 220 ILCS 5/9-201(c); 220 ILCS 5/9-101. The Act provides the Commission with ample authority to ensure “just, reasonable, safe, proper, adequate or sufficient rules, regulations, practices, equipment, appliances, facilities, service or methods to be observed, furnished, constructed, enforced or employed[.]” 220 ILCS 5/8-501.

The City asserts that PGL bears the burden of proof in this case to establish the justness and reasonableness of its rate increase. 220 ILCS 5/9-201(c). The City adds that PGL must provide substantial evidence to prove that its costs and expenses are reasonable in amount and prudently incurred. *BPI* 1 at 196.

5. CUB/PCR/City’s Position

CUB/PCR/City state the Act provides that regulated utilities may only recover through rates those costs to provide service which the utility proves are both reasonable and prudent. 220 ILCS 5/9-101; *see Citizens Util. Bd. v. Ill. Commerce Comm’n*, 276 Ill. App. 3d 730, 746 (1st Dist. 1995). CUB/PCR/City contend the Commission’s decision regarding the reasonableness and prudency of the Companies’ costs must be supported by substantial evidence, that is, “evidence that a reasoning mind would accept as sufficient to support a particular conclusion.” *Commonwealth Edison Co.*, 405 Ill. App. 3d at 398. CUB/PCR/City add the approved costs must represent the Companies’ “least-cost means of meeting the utility’s service obligations.” 220 ILCS 5/8-401.

6. PIOs’ Position

Fundamentally, in this rate case, the Commission must establish rates that are just and reasonable. 220 ILCS 5/9-201(c); 220 ILCS 5/9-101. Illinois courts have held the Commission must analyze the impact of the utility’s proposed tariffs on consumers to reach a just and reasonable determination. *See Abbott Lab. v. Ill. Com. Comm’n*, 289 Ill. App. 3d 715-716 (1st Dist. 1997); *Citizens Util. Bd. v. Ill. Commerce Comm’n*, 276 Ill. App. 3d 730, 738 (1st Dist. 1995) (citations omitted). Ultimately, the public must “pay no more than the reasonable value of the utility’s services.” *Id*. The Act requires those utility services must not only be “adequate, efficient, reliable, and environmentally safe,” but also must represent the “least-cost means of meeting the utility’s service obligations.” 220 ILCS 5/8-401.
As the parties seeking a rate increase, the Companies bear the burden of proof in this proceeding. That means the Companies bear the burden of persuading the Commission that their proposed rates are just and reasonable based upon a preponderance of the evidence in the record. 5 ILCS 100/10-15; 220 ILCS 5/9-201(c). Further, the Companies bear the burden of persuading the Commission that their investments are prudent, used and useful, and just and reasonable. 220 ILCS 5/9-211, 5/9-212.

7. Commission Analysis and Conclusion

There is no dispute that as to rate base investments the Act requires:

The Commission, in any determination of rates or charges, shall include in a utility’s rate base only the value of such investment which is both prudently incurred and used and useful in providing service to public utility customers.

202 ILCS 5/9-211.

The Commission must also assure that the resulting rates are just and reasonable, the standard acknowledged by the parties and set forth in the Act:

If 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. In such hearing, the burden of proof to establish the justness and reasonableness of the proposed rates or other charges, classifications, contracts, practices, rules or regulations, in whole and in part, shall be upon the utility.

220 ILCS 5/9-201(c).

The utility has the statutory burden of proof to establish the appropriateness, “in whole and in part,” of its investments, costs, and the resulting rates. Id., 5 ILCS 100/10-15. The utility must establish that its proposed investments are “prudently incurred and used and useful,” and that the resulting rates and proposed practices are “just and reasonable” – based on the evidence of record.

The Companies cite language from City of Chicago to argue that when a utility “has established a prima facie case, . . . the burden then shifts to others to show that the costs incurred by the utility are unreasonable because of inefficiency or bad faith.” City of Chicago v. Ill. Commerce Comm’n, 133 Ill. App. 3d 435, 442 (1st Dist. 1985). However, the language from that decision addresses only the burden of production. The City of Chicago decision specifically “reject[ed] the People’s contention that the Commission illegally shifted the burden of going forward with evidence to the intervenors.” Id. at 443. The decision is clear that the burden that shifted to intervenors is the burden of production...
In this case, numerous elements of the Companies’ *prima facie* case have been sufficiently met with opposing evidence. At all times, the utility in a rate case has the statutory burden of proof and bears the risk of non-persuasion. *See Business & Prof'l People v. Ill. Commerce Comm'n*, 146 Ill. 2d 175, 196 (1991) (“Throughout the rate proceedings, the utility has the burden of proving that its investments meet [the legal standard].”); *see also* Ill. Rules of Evid. 301.

To prevail on an issue, the utility must meet its burden of proof by a “preponderance of the evidence.” 5 ILCS 100/10-15. In a rate case, the Commission is obligated to determine, from the proposals and evidence of record, just and reasonable versions of the proposed rates and practices. The Commission may select, modify, or meld proposals, or craft from the record evidence, those rates or practices it finds just and reasonable. 220 ILCS 5/9-201(c) (“[T]he Commission shall establish the rates . . . [or practices] proposed, in whole or in part, or others in lieu thereof, which it shall find to be just and reasonable.”). On appellate review, the Commission’s findings must be supported by “substantial evidence” based on the record. *Citizens Util. Bd. v. Ill. Commerce Comm'n*, 166 Ill. 2d 111, 120 (1995) (citing 220 ILCS 5/10-201(e)(iv)(A)-(D)); *see also* Rodriguez v. VA, 8 F.4th 1290, 1298 (2021) (“‘Preponderance of the evidence’ is a burden of proof, while ‘substantial evidence’ is a standard of review”).

The AG cites Article I of the Act to support its argument that the Act requires the Commission to apply a least-cost standard. However, the statements of legislative intent and objectives in Article I guide the Commission’s interpretation and implementation of the Act. More particularly, the Commission’s determinations of whether costs and rates are just and reasonable or an investment is prudent and used and useful, necessarily consider the relative costs of alternatives, even without an express requirement for stand-alone least cost analyses. This construction of the Act is reinforced by the requirement of Section 8-401 that utilities meet their service obligations through least cost means.

Every public utility subject to this Act shall provide service and facilities which are in all respects adequate, efficient, reliable and environmentally safe and which, consistent with these obligations, constitute the least-cost means of meeting the utility’s service obligations.

220 ILCS 5/8-401.

To be clear, there is no express requirement in the Act for a least-cost analysis in rate cases, and the Commission has not previously required such an analysis in general rate cases. The Commission declines to do so now.

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1 The Commission declines to follow decisions in earlier dockets that reflect this misreading of *City of Chicago*. 
II. REVENUE REQUIREMENT

A. North Shore

North Shore’s final proposed base rate revenue requirement increase is $16.5 million, or $16.6 million if costs recovered as Other Revenues are included. NS-PGL Ex. 24.01N, Sch. 1.01 N, 1.02 N, 1.05 N. North Shore’s final proposed rate base is $429.1 million, reflecting adjustments proposed by Staff and intervenors that the company accepted in whole or in part, as well as certain updates. NS-PGL Ex. 24.01N, Sch. 1.03 N, 1.04 N. Because of various adjustments discussed below, Staff’s proposed rate base is $423.8 million, and the AG’s proposed rate base is $422.3 million.

B. Peoples Gas

Peoples Gas’ final proposed revenue requirement increase is $401.1 million, or $405.7 million if costs recovered as Other Revenues are included. NS-PGL Ex. 24.01P REV, Sch. 1.01 P, 1.02 P, 1.05 P. Peoples Gas’ final proposed rate base is $4.8 billion, reflecting adjustments proposed by Staff and intervenors that the company accepted in whole or in part, as well as certain updates. NS-PGL Ex. 24.01P REV, Sch. 1.03 P, 1.04 P. Because of various adjustments discussed below, Staff’s proposed rate base is $4.6 billion, and the AG’s proposed rate base is $4.4 billion.

III. TEST YEAR

The Companies proposed a forecasted test year of calendar year 2024. This test year corresponds with the Companies’ fiscal year and is appropriate under 83 Ill. Adm. Code 287.20(b). No party objected to the proposed test year, and it is therefore approved.

IV. OVERALL RATE BASE

A. Uncontested Issues

1. Gross Utility Plant

   a. Historic Plant Balances

      In direct testimony, the Companies provided actual plant balances for 2020 and 2021. NS Ex. 2.2 REV, Sch. B-5; PGL Ex. 2.2 REV, Sch. B-5. Companies witness Zgonc explained the derivation of these plant balances. NS Ex. 2.0 REV at 43, PGL Ex. 2.0 REV at 47. No party contests the 2020 and 2021 plant balances and they are therefore approved.

   b. 2022 Plant Balances

      In direct testimony, the Companies provided a partial forecast (six months of actual, six months of forecasted data) for 2022 plant balances. NS Ex. 2.2 REV, Sch. B-5; PGL Ex. 2.2 REV, Sch. B-5. Companies witness Zgonc explained the derivation of these plant balances. NS Ex. 2.0 REV at 43, PGL Ex. 2.0 REV at 47. No party contests the 2022 plant balances and they are therefore approved.

   c. 2023 and 2024 Forecasted Capital Additions

      The Companies provided forecasts of 2023 and 2024 plant balance to be included in rate base. NS Ex. 2.2 REV, Sch. B-5; PGL Ex. 2.2 REV, Sch. B-5. The Companies updated these forecasts in rebuttal testimony based on plant actuals as of April 2023.
NS-PGL Ex. 13.0 at 30; NS-PGL Ex. 13.1N, Sch. 1.04 N; NS-PGL Ex. 13.1P, Sch. 1.04 P. Other than certain major capital projects, discussed below, the forecast 2023 and 2024 plant additions are uncontested and are therefore approved.

Pursuant to 83 Ill. Adm. Code 285.6100, the Companies identified major capital projects added to rate base since their last rate case based on a financial threshold specific to each utility. For North Shore, that threshold was a cost greater than 0.2% of net plant or $1.0 million, whichever is higher. NS Ex. 3.0 REV at 11. For Peoples Gas, that threshold was a cost greater than 0.2% of net plant or $10.0 million, whichever is less. PGL Ex. 3.0 REV CORR at 10.

North Shore’s net plant as of December 31, 2021, was $759.2 million and 0.2% of that amount is $1.5 million. Therefore, a major capital project for North Shore would be one that costs more than $1.5 million. NS Ex. 3.0 REV at 11–12. The six major capital projects that exceed that threshold are identified in NS Ex. 3.1. Id. at 12.

Peoples Gas’ net plant as of December 31, 2021, was $6.5 billion and 0.2% of that amount is $12.9 million. Therefore, a major capital project for Peoples Gas would be one that costs more than $10.0 million. PGL Ex. 3.0 REV CORR at 10–11. The 19 major capital projects that exceed that threshold are identified in PGL Ex. 3.1. Id. at 11.

These projects were all undertaken to allow the Companies to continue to provide safe and reliable natural gas service to customers. They range from feeder station expansions to smart metering installations to improvements in customer service technology. See generally NS Ex. 3.0 REV, PGL Ex. 3.0 REV CORR. Except as discussed in Section IV.B.1 (“Contested Projects”), no party contests any of these capital investments.

2. Original Cost of Gross Plant Balance

Staff and the Companies agree to the original cost determination of $765.7 million and $6.6 billion for North Shore and Peoples Gas, respectively, as of December 31, 2021. NS Ex. 2.0 REV at 47, PGL Ex. 2.0 REV at 51; NS Ex. 2.2 REV at Sch. B-5; PGL Ex. 2.2 REV at Sch. B-5; Staff Ex. 2.0 at 21. These amounts are approved. Staff witness Alan proposed language for the associated Findings and Ordering paragraphs, to which the Companies agreed and are included herein. Staff Ex. 2.0 at 21. The proposed language, which is also uncontested, is adopted in the Findings and Ordering paragraphs.

3. Accumulated Provision for Depreciation and Amortization

In his direct testimony, Mr. Zgonc provided historic balances for Accumulated Provision for Depreciation of Gas Utility Plant (ICC Account 108) and Accumulated Provision for Amortization and Depletion of Gas Utility Plant (ICC Account 111), as well as forecasts for 2022 through 2024. NS Ex. 2.0 REV at 37, 44, PGL Ex. 2.0 REV at 40, 48; NS Ex. 2.2 REV at Sch. B-1, Sch. B-6; PGL Ex. 2.2 REV at Sch. B-1, Sch. B-6.

The provisions for depreciation for calendar years 2021 through 2024 are shown as increases to the Depreciation Reserve Balance, and retirements of depreciable property, at original cost, for the same period are shown as decreases to the Depreciation Reserve Balance. NS Ex. 2.0 REV at 45, PGL Ex. 2.0 REV at 49; NS & PGL Exs. 2.2 REV, Sch. B-6. The adjusted average Depreciation Reserve Balance for the 2024 test year is $300.1 million for North Shore and $1.9 billion for Peoples Gas. NS-PGL Ex.
24.01N at Sch. 1.03 N, line 2; NS-PGL Ex. 24.01P REV at Sch. 1.03 P, line 2. These amounts are uncontested and are therefore approved.

4. Qualified Infrastructure Plant Amounts (PGL only)

With the elimination of the Qualifying Infrastructure Plant Rider ("Rider QIP") at the end of 2023, any 2024 return of and on plant that previously could have been recovered via Rider QIP is included in the base revenue requirement for the test year instead. PGL Ex. 2.0 REV at 30. As a result, Schedule C-2.6 (Rider QIP) shows a zero amount. Id.; PGL Ex. 2.1 at Sch. C-1, line 7.

At the same time, PGL's QIP-eligible investments since its last rate case are being moved into rate base. PGL Ex. 3.0 REV CORR at 51–52. Together with amounts that were subject to recovery under other riders, this results in a $3.2 billion increase in net utility plant (gross plant less accumulated depreciation). PGL Ex. 2.0 REV at 39. Those amounts are subject to review and potential adjustment in separate, annual QIP reconciliation proceedings. PGL Ex. 3.0 REV CORR at 52. Meanwhile, no party contests their inclusion in rate base for purposes of the 2024 test year and they are approved.

Staff recommends the Commission Order include a Findings and Ordering paragraph which states:

(x) the QIP costs related to the 2016, 2017, 2018, 2019, 2020, 2021, 2022, and 2023 QIP costs included in the revenue requirement are subject to review for prudence and reasonableness adjustments in the applicable annual QIP reconciliations and

Staff Ex. 2.0 at 19. This language is uncontested and it is therefore adopted as a Findings and Ordering paragraph.

5. Intangible Plant

Mr. Zgonc's direct testimony included $26.2 million for North Shore's intangible plant and $187.6 million for Peoples Gas' intangible plant in rate base, consisting primarily of software for computer systems that support multiple business functions and are necessary for both Companies' business. NS Ex. 2.0 REV at 37, PGL Ex. 2.0 REV at 41; NS Ex. 2.2 REV at Sch. B-5, line 5; PGL Ex. 2.2 REV at Sch. B-6, line 6. No party contests these amounts and they are therefore approved.

6. Production Plant

Mr. Zgonc's direct testimony included $14.2 million for North Shore's production plant and $9.4 million for Peoples Gas' production plant in rate base, consisting primarily of structures and assets associated with liquefied petroleum plant for North Shore and of land or land rights and structures on former manufactured gas production plants purchased by Peoples Gas. NS Ex. 2.0 REV at 37, PGL Ex. 2.0 REV at 41; NS Ex. 2.2 REV at Sch. B-5, line 6; PGL Ex. 2.2 REV at Sch. B-5, line 7. No party contests these amounts and they are therefore approved.
7. Materials and Supplies

Mr. Zgonc provided historical balances for materials and supplies, net of accounts payable, as well as forecasts for 2022 through 2024, in his direct testimony. NS Ex. 2.0 REV at 45, PGL Ex. 2.0 REV at 49; NS & PGL Exs. 2.2 REV at Sch. B-8.1; PGL Ex. 2.2 REV at Sch. B-8.1.

Mr. Zgonc explained that this account represents continuing, permanent investments in materials and supplies that the Companies must maintain to provide service to their customers, so the Companies should be allowed to earn a return on those items. NS Ex. 2.0 REV at 45-46, PGL Ex. 2.0 REV at 49–50. The 13-month (net) average for this account for the test year is $3.1 million for North Shore and $21.7 million for Peoples Gas. NS Ex. 2.2 REV at Sch. B-1 at line 5, Sch. B-8.1; PGL Ex. 2.2 REV, Sch. B-1 at line 5, Sch. B-8.1. No party contests these amounts and they are approved.

8. Gas in Storage

Mr. Zgonc provided the 13-month average balances of gas in storage for calendar year 2021, as well as projected data for calendar years 2022 through 2024; as filed, these balances were $12.3 million for North Shore and $41.9 million for Peoples Gas. NS Ex. 2.0 REV at 36, PGL Ex. 2.0 REV at 39–40; NS Ex. 2.2 REV at Sch. B-1, line 6, Sch. B-1.1; PGL Ex. 2.2 REV at Sch. B-1, line 6, Sch. B-1.1. Staff witness Seagle recommended that the Companies update these figures to reflect the most up-to-date information (Staff Ex. 7.0 at 7–8), and Mr. Zgonc did so in rebuttal, reflecting the most current information as of March 2023. NS-PGL Ex. 13.0 at 29. The resulting balances decreased by $29,000 for North Shore and increased by $2.2 million for Peoples Gas. Id. Mr. Seagle confirmed that he had no concerns with these updates, and no other party contests these amounts. Staff Ex. 15.0 at 2. These amounts are therefore approved.

9. Budget Plan Balances

Budget Plan Balances may be a component of (reduction to) rate base when they provide a source of capital. The 13-month average Budget Plan Balance is a $2.2 million credit for North Shore and an $8.1 million credit for Peoples Gas. NS Ex. 2.0 REV at 36, PGL Ex. 2.0 REV at 39–40; NS Ex. 2.2 REV at Sch. B-1, line 6, Sch. B-1.1; PGL Ex. 2.2 REV at Sch. B-1, line 6, Sch. B-1.1. These amounts are uncontested and are therefore approved.

10. Accumulated Deferred Income Taxes

The inclusion of Plant in Service in rate base is subject to reduction for the applicable associated accumulated deferred income taxes (“ADIT”). Subject to any flow-through effects of proposals to eliminate retirement benefits from rate base, which the Companies oppose (see Section IV.B.3), North Shore’s final ADIT credit of $115.4 million and Peoples Gas’ final ADIT credit of $1.0 billion are uncontested. NS Ex. 2.0 REV at 46, PGL Ex. 2.0 REV at 50; NS Ex. 2.2 REV at Sch. B-1, line 10, Sch. B-9; PGL Ex. 2.2 REV, Sch. B-1, line 10, Sch. B-9. These amounts are approved.

11. Customer Deposits

For customer deposits, North Shore has an adjusted test year average credit balance of $0.4 million, and Peoples Gas has an adjusted test year average credit
balance of $1.3 million. NS Ex. 2.0 REV at 46, PGL Ex. 2.0 REV at 50; NS Ex. 2.2 REV at Sch. B-1, line 11, Sch. B-13; PGL Ex. 2.2 REV at Sch. B-1, line 11, Sch. B-13. The amounts are uncontested and are therefore approved.

12. **Customer Advances for Construction**

Customer advances for construction may be a component of (reduction to) rate base when they provide a source of capital. North Shore proposed a credit balance of $1.7 million and Peoples Gas proposed a credit balance of $5.5 million in customer advances. NS Ex. 2.0 REV at 42, PGL Ex. 2.0 REV at 46; NS Ex. 2.2 REV at Sch. B-1, line 12, Sch. B-1.3; PGL Ex. 2.2 REV at Sch. B-1, line 12, Sch. B-1.3. The amounts are uncontested and are therefore approved.

13. **Reserve for Injuries and Damages**

The reserve for injuries and damages may be a component of (reduction to) rate base when it provides a source of capital. North Shore proposed a credit balance of $0.7 million and Peoples Gas proposed a credit balance of $7.2 million for this reserve. NS Ex. 2.0 REV at 42--43, PGL Ex. 2.0 REV at 46; NS Ex. 2.2 REV at Sch. B-1, line 13, Sch. B-1.4; PGL Ex. 2.2 REV at Sch. B-1, line 13, Sch. B-1.4. These amounts and an associated change in accounting treatment are uncontested and are therefore approved.

14. **Capital Additions (Uncontested Projects)**

a. **Overview**

The Companies’ uncontested capital additions are discussed generally in connection with gross utility plant. See Section IV.A.1 above. This Section of the Order provides additional information delineating which of the Companies’ capital additions are and are not contested.

b. **Uncontested Distribution Capital Projects**

All of the Companies’ non-major distribution capital projects (i.e., projects other than those listed on Schedule F-4) as well as the projects listed on Schedule F-4, except as otherwise discussed below, are uncontested and are approved for inclusion in test year rate base.

c. **Manlove Field (PGL only)**

Four of Peoples Gas’ Schedule F-4 projects relate to its Manlove Field Gas Storage Facility. PGL Ex. 3.1 at lines 4, 5, 11, 13. Company witness Westrick explained the need for these projects and supported their inclusion in test year rate base. See generally PGL Ex. 11.0 REV. No party contests the need for, or execution of, these projects and the Commission therefore approves their rate base treatment as proposed by Peoples Gas.

d. **Uncontested F-4 Projects**

Other than as specifically discussed in Section IV.B.1, all of the major capital projects listed on each of the Companies’ Schedule F-4 (NS Ex. 3.1, PGL Ex. 3.1) are uncontested and are approved for inclusion in test year rate base. Only four major capital projects are contested: North Shore’s Clavey Road Phase 2 project (Section IV.B.1.b.i), Peoples Gas’ Maximum Allowable Operating Pressure (“MAOP”) Reconfirmation project
Peoples Gas’ improvements to its shops and related facilities in the City of Chicago (Section IV.B.1.d), and a portion of Peoples Gas’ 2024 investments in its SMP (Section IV.B.1.a).

Staff witness Seagle recommends that the Commission require the Companies to use the most up-to-date information in the calculation of rates ultimately borne by ratepaying customers with regard to Schedule F-4, Capital Plant Additions. Staff Ex. 7.0 at 3. Specifically, Schedule F-4 does not reflect the most accurate and up-to-date values. While some costs had already occurred and were known at the time of the filing, other costs were projected, and some costs are associated with projects that are still ongoing. This can result in actual costs that are higher or lower than originally projected. Id. at 5.

Mr. Seagle explained that, in his understanding, each Companies’ Schedule F-4 covers major capital additions that were completed after North Shore’s and Peoples Gas’ last rate cases, but prior to, or during, the rate case test year in this proceeding. The Companies are allowed to earn a return on these investments until such a time that the assets are sold or fully depreciated. Id. at 4. 83 Ill. Adm. Code 285.6100(a) requires the Companies to provide information concerning plant additions included in rate base on Schedule B-1 that are not currently in the rate base ordered in the utility’s most recent rate proceeding. The minimum cost for each project for which the Companies must provide information is detailed in 83 Ill. Adm. Code 285.6100(a).

North Shore provided information on the top six most costly additions for the years 2022, 2023, and 2024. These are summarized in North Shore’s Schedule F-4, Additions to Plant in Service Since the Last Rate Case. Peoples Gas provided information on the top 17 most costly additions. Some of Peoples Gas’ projects in Schedule F-4 are ongoing while at least one project was completed in 2017. Mr. Seagle understands that the costs for these projects are calculated by the Companies’ engineering staff and finance staff and are approved by the Companies at the management level and for some projects, at the level of the Companies’ Board of Directors. Id. at 5.

To ensure updated information, Mr. Seagle requested that the Companies provide an update to the costs for capital additions with the most recent actual cost data available in rebuttal testimony. Id. If the project is ongoing and the contingency costs for certain projects are not realized, the Companies should factor this into the calculation of the costs for all the projects where applicable in Schedule F-4. Mr. Seagle also requested that the Companies provide by line item the effect of these updates on the revenue requirement. Id. In response to Mr. Seagle’s request, Companies’ witness Eldringhoff provided the requested updates to Schedule F-4; specifically, Ms. Eldringhoff provided revised versions of Schedule F-4 for both Companies to reflect up-to-date capital costs for a limited scope of projects. NS-PGL Ex. 14.05. Mr. Seagle does not dispute the Companies updates. Staff Ex. 15.0 at 2.

15. Cash Working Capital (Uncontested Elements)

Except as addressed in Section IV.B.4 below, all elements of the Companies’ cash working capital calculation are uncontested and are approved as set forth in NS-PGL Ex. 24.01N at Sch. 1.08 and NS-PGL Ex. 24.01P REV at Sch. 1.08.
16. Construction Work in Progress

For North Shore, Mr. Zgonc identified Construction Work in Progress ("CWIP") balances of $4.7 million as of December 31, 2023, and $10.8 million as of December 31, 2024. NS Ex. 2.0 REV at 38. After adjustments to eliminate from CWIP projects that will not go into service after June 30, 2025, North Shore’s as-filed average CWIP balance included in rate base was $7.7 million. Id. at 38–39; see also NS Ex. 2.2 REV at Sch. B-7, Sch. B-7.1. In rebuttal testimony, North Shore reduced this amount to $7.5 million. NS-PGL Ex. 13.1 N at Sch. 1.04 N at 3. North Shore’s CWIP in rate base is uncontested and is approved.

For Peoples Gas, Mr. Zgonc identified CWIP balances of $70.8 million as of December 31, 2023, and $118.5 million as of December 31, 2024. PGL Ex. 2.0 REV at 41–42. After adjustments to eliminate from CWIP projects that will not go into service after June 30, 2025, Peoples Gas’ average CWIP balance as filed included in rate base was $79.2 million. Id. at 42; see also PGL Ex. 2.2 REV at Sch. B-7, Sch. B-7.1. In rebuttal testimony, Peoples Gas reduced this amount to $68.9 million. NS-PGL Ex. 13.1 P at Sch. 1.04 P at 3. With the exception of CWIP for two projects discussed in Section IV.B.2 below, PGL’s CWIP in rate base is uncontested and is approved.

17. Organized Labor and the SMP (PGL only)

Section IV.B.5.a below, discusses issues relating to SMP project management.

B. Contested Issues

1. Capital Additions

   a. 2024 SMP Work

      (i) Companies’ Position

Peoples Gas states that the AG proposes disallowing $62.5 million of 2024 SMP work from rate base on the grounds that over the past five years, Peoples Gas has installed more natural gas main than it retired. While conceding that timing differences can lead to having more pipe installed than retired in a given year, AG witness Walker takes the position that the cost associated with any pipe installed that is more than 10% or 0.5 miles greater than the quantity retired in a given year should be categorically disallowed. Id. If accepted, this proposed disallowance would total nearly a quarter of Peoples Gas’ total anticipated SMP spending in 2024 and would force Peoples Gas to materially slow down its pipe replacement activities in the test year, leaving more dangerous leak-prone pipe in the ground. The AG does not address the corresponding (and significant) safety implications for the City.

The AG’s recommended disallowance stems from just a few lines of Mr. Walker’s direct testimony, which is part of a long section discussing Peoples Gas’ SMP more broadly, focusing mostly on recommending changes to how Peoples Gas reports on the SMP. In those few lines of testimony, Mr. Walker simply observed that more pipe has been installed than retired, and then noted that he had not found an explanation for the difference in Peoples Gas’ direct testimony, discovery, or other filings. AG Ex. 3.0 at 41–42. He then recommends disallowing the cost difference “to the extent these excess installations cannot be justified.” Id. at 43. Mr. Walker and the AG fail to disclose that
neither they nor any other party actually asked any questions in discovery about the difference in this case, although his reference to not finding an explanation in discovery certainly implies that they did. Rather than seeking clarification in discovery or raising the concern again in rebuttal testimony or at hearing, the AG simply let the issue lie, then calculated and advocated for a concrete disallowance for the first time in its Initial Brief.

The Company argues that posing a question in testimony about a discrete aspect of a large capital project does not come anywhere near the sort of evidence that the AG would need to present to carry its burden of proving that nearly one-fourth of SMP spend in the test year is imprudent, unreasonable, or should be disallowed from rate base. Mr. Walker did not explain why installing more main than is retired is unreasonable, except to casually observe that “most utilities most often install a comparable amount of main to that which is being retired.” Id. at 41. Also, the AG did not, at least until its Initial Brief, attempt to quantify any disallowance. None of this approaches the quantum of evidence needed to “show that the costs incurred by the utility are unreasonable because of inefficiency or bad faith” as required under Illinois law. See City of Chi. v. People of Cook Cty., 133 Ill. App. 3d 435, 442 (1st Dist. 1985). Thus, the AG’s proposed disallowance should be rejected as a matter of law.

The Companies state that there is a ready explanation for the difference between miles of pipe installed and miles of pipe retired. First, as Mr. Walker concedes, timing differences play a role — new pipe must be installed, connected to services, and gassed before service can be switched over and old pipe can be retired. Therefore, new pipe is sometimes installed in one year and old pipe is retired in the next. Second, and more significantly, a core element of the SMP is the practice of “double deckening” where possible. This means that where it is less expensive or preferred from an engineering perspective to do so, pipe will be laid in on both sides of a street (typically in parkways), replacing a single pipe that was laid under the street. The result is that for areas that are double decked, twice as much new pipe is installed as is retired. Double deckening offers several advantages, including the ability to isolate smaller sections of main for repairs, cost savings due to avoiding restoration of streets, and easier maintenance. This practice was the subject of extensive discussions in Docket No. 16-0376, the Commission-initiated investigation of the SMP, which involved extensive workshops and wide-ranging discovery, testimony and briefing on SMP design, execution, and cost, including various approaches to prioritizing pipe for replacement, project pace, and annual spend needed to achieve program goals. Double deckening is referenced in the Final Order in that case although, tellingly, not by the AG. Ill. Commerce Comm’n on Its Own Mtn. v. Peoples Gas Light & Coke Co., Docket No. 16-0376, Order at 54 (Jan. 10, 2018).

Despite the AG’s professed ignorance about the reasons that more pipe might be installed than retired, the AG is very well aware of double deckening. The practice has been the subject of extensive discovery in the 2016 Rider QIP reconciliation proceeding, including discovery by the AG itself. Peoples Gas Light & Coke Co., Docket No. 17-0137. It is not credible for the AG to now claim ignorance of the issue and urge disallowance of nearly a fourth of 2024 SMP spend as a result.
(ii) AG’s Position

The AG asks the Commission to disallow $62.5 million for unjustified distribution pipe PGL installed in excess of the miles retired; and require PGL to use cost per retired mile, and not cost per installed mile, as the benchmarking metric for future work on its SMP, which will enhance transparency and eliminate PGL’s ability to both disguise the program’s high cost and leave unexplained the variance between miles retired and miles installed.

The AG asks the Commission to disallow $62.5 million in distribution plant because PGL failed to justify why it routinely installs 75% more pipe than it retires for SMP Neighborhood projects and offered no explanation for using miles and services “installed” rather than “retired” as the benchmarking metric for the SMP retirement program. Mr. Walker identified PGL’s practice of routinely installing — without explanation — on average, 75% more pipe that it retires through its SMP Neighborhood Program. AG Ex. 3.00 at 41. According to the AG, nowhere in PGL’s testimony, schedules, workpapers, or responses to discovery does it explain the reason for this discrepancy. Id. Mr. Walker added that while “there can be a lag from calendar year to calendar year that would result in some amount of pipe being retired in one year and then the replacements being installed in the following calendar year,” nothing in the record justifies the installation of the additional pipe he identified. Id.

Based on this finding, Mr. Walker concluded that for the 2024 test year — and all future years — PGL should be “required to demonstrate the necessity of installing more mileage than it retires for each project that the difference between installed and retired is greater than 10% and 0.5 miles.” Id. at 43. To the extent that the excess installations SMP cannot be justified, he testified that “the Commission not allow the recovery of costs associated with such work.” Id. As the record is devoid of any justification, the AG asks the Commission to disallow $62.5 million of PGL’s distribution capital budget.

The AG requests the Commission order PGL to use cost per retired mile, and not cost per installed mile, as the benchmarking metric for future SMP work. The AG argues that their proposed disallowance of $62.5 million properly represents the difference in cost between installed and retired miles that PGL proposes to recover in this rate case, and that PGL’s use of cost per installed mile wrongly disguises the high cost of the program.

According to Mr. Walker, the disparity between miles retired and miles installed obfuscates the true cost of the SMP on a per-mile basis. AG Ex. 3.00 at 42. Mr. Walker referenced PGL’s Quarterly SMP Report filing that demonstrates PGL’s use of the “cost per mile of pipe installed” as its primary metric for unit costs. AG Ex. 3.00 at 40. The AG contends that PGL’s cost per installed mile approach is inconsistent with a program designed to retire leak prone pipes (“LPP”), and that PGL’s method disguises the high cost of the program and lacks any explanation for the variance between miles retired and miles installed. For these reasons, the AG asks the Commission to direct PGL to use cost per retired mile, not cost per installed mile, as the benchmarking metric for future SMP work.
(iii) City’s Position

The City highlights that PGL’s SMP is the largest driver of PGL’s proposed rate increase. PIO Ex. 1.0 at 25. PGL forecasts $280 million of investment through the SMP in 2024, of which approximately $265 million PGL claims will be in service during this test year. PGL Ex. 1.0 REV at 13. PGL’s parent company, WEC, estimates that it will continue investing between $280 million to $300 million annually in the SMP. COC Ex. 1.0 at 24. The City notes that, in 2016, PGL’s target end date was between 2035 and 2040 (NS-PGL Ex. 12.0 REV at 19), but this year, PGL states that many of its projects will not be completed until 2040, the outer boundary of its target end date. COC Ex. 3.0 at 18, citing COC Ex. 3.03 at 26. PGL witness Eidukas explains that the SMP “will replace over 2,000 miles of pipe and improve the long-term safety and reliability of the natural gas delivery system by converting the system from low to medium pressure, moving meters outside, and installing safety equipment.” PGL Ex. 1.0 REV at 8. However, PGL reports that, as of October 2022, it has completed only about 35% of the SMP. Id. at 8.

The City argues that, since the Commission last evaluated the SMP in Docket No. 16-0376, there have been significant changes in circumstance. According to the City, the passage of Public Act 102-0662 (“P.A. 102-0662”) and the issuance of the City’s Climate Action Plan, among other actions on the federal, state, and local levels, have fundamentally altered the trajectory of the City’s energy future, with important implications for affordability. The City argues that the SMP must evolve in this new energy environment to avoid the risk of stranded assets and unaffordable rates for PGL customers. See COC Ex. 1.0 at 25; PIO Ex. 1.0 at 8, 10. The City notes that, given these significant changes, multiple experts in this proceeding recommend improvements to the SMP or reevaluating the program altogether. See COC Ex. 3.0 at 3, 19; PIO Ex. 4.0 at 20; AG Ex. 7.0 at 14.

The City emphasizes that the Commission’s Order in Docket No. 16-0376 explicitly acknowledged the need for future review of the SMP, given the long-term nature of the program. The Commission found that “[i]n a long term project like this it will be necessary for the Commission to continue to monitor the ramifications of the SMP.” Docket No. 16-0376, Order at 40. The Commission also stated that “[b]ased on the information provided in the record and during Phase II of this proceeding, the Commission finds that affordability must be studied and considered as the program continues.” Id. at 128.

The City highlights that its witness Deleon detailed affordability concerns, analyzing Appendix A of PGL’s Safety Modernization Report for the quarter ending March 31, 2023. COC Ex. 3.0 at 18. Dr. Deleon first explained that, according to the Appendix A table, construction would not begin in many of the listed neighborhoods for over a decade. Id. at 18. Dr. Deleon also highlighted that there are several P.A. 102-0662-defined Equity Investment Eligible Communities with significant replacement costs. Id. at 18. For instance, PGL plans to install 70 miles of pipe and 6,631 meters in Englewood, with a total cost of $175 million. Id. at 19. Dr. Deleon opined that installing this new gas infrastructure in 2036, as currently planned, would present significant financial challenges for Englewood residents to transition to cleaner alternatives. Id. at 19.

The City argues that the expiration of the QIP rider mechanism is yet another reason favoring SMP reevaluation. The City points to People ex rel. Raoul v. Ill.
Commerce Comm’n, 2019 IL App (1st) 180679-U, in which the Illinois Appellate Court reviewed an appeal of the Commission’s Order in Docket No. 16-0376 regarding the Commission’s ability to review the SMP while the Rider QIP statute was in effect. The Court found that, although the Rider QIP statute limited the Commission’s review of the SMP’s prudency, justness, and reasonableness at that time, that would no longer be the case when the statute is repealed on December 31, 2023. *Id.* at ¶ 42, see 220 ILCS 5/9-220.3. The Court stated:

section 9-220.3 suspends the Commission’s obligation to determine the justness and reasonableness of rate changes which are required in all other instances. The limited timeframe under which gas utilities may take advantage of the cost recovery mechanism outlined coincides with the Commission’s reading . . . that the provisions of sections 9-220.3 are intended to function as a guarantee rather than a simple possibility of recovering investments on infrastructure. The fact that the SMP will continue past the effective date of this provision, provided that no further action is taken by the Legislature, simply means that the later years of the SMP will be governed by the traditional principles of Commission oversight and traditional ratemaking[.]

*Id.* at ¶ 58.

The City argues that those “traditional principles of Commission oversight” include a reevaluation of the SMP. The City asks that, as part of that reevaluation, the Commission direct PGL to conduct a Joint Feasibility Assessment of a portion of its service territory, working with the City and other interested and affected stakeholders to assess the potential for strategic electrification and retirement of leak-prone pipe. The City explains that this new proceeding should also analyze the costs and benefits associated with the SMP and analyze whether all aspects of the SMP, such as the pace and cost of moving meters from the inside of customers’ premises to the outside, are still warranted. The City emphasizes that exploring this idea as a pilot also allows the Commission to test the program’s impact on advancing equity and reducing GHG emissions. *Id.* at 34. The City supports the AG’s proposed disallowance of 2024 SMP work from rate base for unjustified distribution pipe that PGL installed in excess of miles retired.

**(iv) PIOs’ Position**

PIO explain that the SMP is the cornerstone of Peoples Gas’ investments in its aging distribution system. The SMP involves three primary elements: (1) removal of the significant amount of risky, leak-prone, cast iron and ductile iron pipe in Peoples Gas’ system; (2) increasing system pressure from low to medium; and (3) relocation of meters from inside of customers’ premises to the outside. PIO Ex. 1.0 at 27. Peoples Gas states it has completed roughly 35% of its SMP activities, and forecasts spending $280-$300 million per year on the SMP going forward. PGL Ex. 1.0 at 8.

Despite the fact that the SMP represents a significant portion of PGL’s test year capital spending and a critical component of the PGL’s efforts to improve system safety,
PIO posit that PGL’s presentation of the SMP in this proceeding is opaque and defensive. As an example — in direct testimony, AG witness Walker observed that between the years 2018 and 2022, there has been a significant discrepancy between the miles of pipeline installed and miles of pipeline retired through the SMP. AG Ex. 3.0 at 41. During that time, Peoples Gas installed 75% more main that it retired, on average, through its Neighborhood Program (a sub-program of the SMP). While Peoples Gas noted Mr. Walker’s criticism of that discrepancy, it chose not to explain it in its rebuttal or surrebuttal testimony. Instead, PGL argued its approach to the SMP has been litigated and audited in previous dockets, and that the Commission should not reconsider PGL’s approach in a rate case. See NS-PGL Ex. 12.0 at 21; NS-PGL Ex. 14.0 at 18. Similarly, in response to the Commissioners’ Question 5b, which asked PGL to discuss alternatives to its current approach to the SMP, PGL did not offer anything new, and instead focused on a review of the SMP conducted years ago.

PIO maintain that PGL’s refusal to consider changes to the SMP is concerning not only because the SMP represents a large part of its test year spending and will continue to represent a large part of the PGL’s spending for years to come, but also because the SMP has not been effective. The program’s cost has ballooned over time — Peoples Gas estimated the program would cost $1.4 billion in 2007, then, eight years later, estimated the program would cost up to $11 billion. PIO Ex. 1.0 at 28. Despite PGL’s significant investment in pipeline replacement through the SMP, the program has not led to a notable reduction in pipeline failure rates. Id. at 27. In fact, AG witness Walker testified that, with respect to the specific leak metrics that best describe the condition of the distribution system, Peoples Gas’ system has either not improved or worsened over the course of the SMP program. AG Ex. 3.00 at 22. More specifically, several categories of Peoples Gas’ Grade 1 leaks increased between 2013 and 2022, as did its Grade 2 and Grade 3 leaks. Id. at 23.

PIO explain that there are at least two reasons the SMP has not been effective in reducing leaks to date. First, the scope of the SMP program is broad. As explained above, under the SMP, Peoples Gas not only addresses safety risks by replacing leak-prone pipe (i.e., pipes made of leak-prone materials such as ductile and cast iron), it also increases the pressure of its system from low to medium. The Neighborhood Program in particular, one of the several sub-programs under the SMP, combines multiple elements, including leak-prone pipe replacement and a medium pressure upgrade. PIO Ex. 1.0 at 28. By combining risk reduction work with other scope elements, the Neighborhood Program dilutes PGL’s focus on risk reduction. As Liberty summarized in its Phase I audit report of the Accelerated Main Replacement Program (“AMRP”), the precursor to the SMP, “[c]ombining leak-prone pipe replacement with pressure increase and meter relocation work promotes installation efficiency, but raises concerns about prioritizing pipe replacement work.” See PIO Reply to Commissioners’ Question 5 at 3 (citing Peoples Gas AMRP Investigation – Phase One Final Report, May 15, 2015).

PIO note that while PGL has not presented a current, disaggregated cost estimate (or completion timeline) for each of the SMP’s distinct elements, including the Neighborhood Program (see Peoples Gas Response to Commissioners Question 5 (presenting 2015 cost estimates for the SMP); PIO Reply to Commissioners’ Question 5), publicly available data partially illustrates the impacts of PGL’s packaging of multiple
elements into the SMP. According to the 2022 Pipeline and Hazardous Materials Safety Administration ("PHMSA") annual gas distribution report, Peoples Gas had 1,157 miles of leak-prone cast iron and ductile iron main in its system at the end of 2022 — the material types that PGL targets for replacement through the SMP. PIO Ex. 1.0 at 29. However, according to the Peoples Gas 2022 Q4 SMP report, PGL plans to retire 1,563 more main miles through the SMP. Id. at 29. PIO explain that the discrepancy between the amount of leak-prone pipe on PGL’s system, and the amount of pipe it plans on replacing, indicates PGL is planning on expending significant efforts on projects unrelated to the major safety risk (leak-prone cast iron and ductile iron pipe) the SMP purports to address. Id. at 29. PGL, however, has not produced a current, disaggregated cost estimate (or completion timeline) for each of the SMP’s distinct components.

Second, PGL has not adopted a metric that assesses the impact of its SMP spending on risk reduction or safety improvement. PIO explain that PGL has historically ignored stakeholders’ requests to adopt such a metric or claimed that adoption of such a metric was infeasible. Id. at 29. As a result, PIO state that it is not clear that PGL effectively targets its most leak-prone pipes for replacement. AG Ex. 3.00 at 8. PIO attempted to obtain granular data from PGL that would allow the Commission and stakeholders the ability to evaluate PGL’s pipe replacement prioritization process. However, Peoples Gas refused to provide this data. PIO Ex. 1.2 at 51-52.

PIO assert that, in light of PGL’s plan to invest $280-$300 million in the SMP for the next several years, the imperative that Peoples Gas effectively mitigate the risks posed by leak prone ductile iron and cast iron pipe, and the likelihood that electrification will require PGL to spread its costs over fewer sales in the future, the Commission must revisit the SMP and ensure the program is focused on effective risk reduction. PIO state that highest-risk pipe replacements should take priority, whereas the Commission should deemphasize replacement of lower risk pipe and investments necessary to upgrade system pressure. PGL should reconfigure the Neighborhood Program in particular, and disentangle PGL’s leak prone pipe replacement and pressure upgrade efforts under that program so that PGL can focus on risk reduction going forward.

In response to these recommendations, Peoples Gas witnesses Eidukas and Eldringhoff dismissed the need to reform PGL’s SMP by asserting that it has been extensively litigated in the past (in particular, in Docket Nos. 16-0376 and 18-1092) and that it would be costly to change course midstream. NS-PGL Ex. 12.0 at 18-21; NS-PGL Ex. 14.0 at 18-19; see also Peoples Gas Response to Commissioners’ Question 5. Peoples Gas leans in particular on an engineering review of PGL’s cast iron and ductile iron distribution system conducted by Kiefner and Associates, Inc. (Kiefner) in Docket 18-1092, which recommended PGL replace all cast iron and ductile iron pipes in its system by 2030. Based on the Kiefner study and the Commission’s prior decisions, PGL concludes the Commission has already endorsed Peoples Gas’ approach to the SMP, rendering intervenors’ criticism of that approach moot.

PIO request that the Commission reject this argument for several reasons. First, the Commission is not bound by its prior decisions and has the power to change course in this proceeding. PIO note that the Commission is free to reverse its decision in any prior docket because it “is not a judicial body and its orders do not have the effect of res judicata; the Commission, as a regulatory body[,] must have the authority to address each
matter before it freely, even if it involves issues identical to a previous case.” Lakehead Pipeline Co. v. Ill. Commerce. Comm’n, 296 Ill. App. 3d 942 at 956 (3d Dist. 1998). In fact, the Commission specifically anticipated that it would revisit the SMP in this case. During its January 10, 2018 Regular Open Meeting where it last addressed the SMP, then-Chairman Sheahan noted: “After 2023, recoupment of utility investment in this program will revert to traditional rate cases where the [Commission] will have greater leverage.” Minutes of the Commission Regular Open Meeting at 52 (Jan. 10, 2018).

Further, while the Commission may have addressed the SMP in previous cases, PIO state that changed circumstances warrant a new approach. The Commission’s prior examination of the SMP in Docket No. 16-0376 occurred in the context of the QIP program — which the Commission held did not permit the Commission to address SMP cost recovery outside of annual reconciliation proceedings. Docket No. 16-0376, Order at 210. That examination also occurred prior to P.A. 102-0662’s enactment, which set the state firmly on a path to a decarbonized economy. Finally, as described above, market and policy forces have accelerated electrification in recent years. Nothing in Docket Nos. 16-0376 or 18-1092, or any prior Commission decision, requires the Commission to ignore these significant changes in this case.

Second, the Kiefner study—which recommended PGL replace all leak-prone pipe by 2030, and on which PGL leans heavily — analyzed the state of PGL’s infrastructure, not whether the SMP was optimally designed to reduce risks associated with that infrastructure. PIO Ex. 4.0 at 23. The Kiefner study underscored the importance of rapid risk reduction on PGL’s aging distribution system. PIO maintain that the Kiefner study therefore does not undermine the PIOs’ recommendations, it supports those recommendations. In light of the Kiefner study’s recommendations, it is even more important that the Commission ensure the SMP is tailored to maximizing effective risk reduction going forward.

Third, PGL has failed to justify its SMP investments in this rate case. PIO note that PGL bears the burden to demonstrate through the preponderance of record evidence that its investments are prudently incurred, used and useful, and just and reasonable. 220 ILCS 5/9-201(c), 9-211, 9-212. PIO maintain that PGL cannot carry its burden to prove that its investments are prudent in light of the SMP program’s limited success, substantial cost overruns, impacts on customer affordability, and stranded asset risks. Moreover, the opaqueness of the program makes it difficult for parties to even evaluate PGL’s risk prioritization process, let alone determine whether this process leads to prudent investments. PIO posit that PGL’s significant and unjustified discrepancy between miles of pipeline installed and miles of pipeline retired is a striking example of the need for more scrutiny of the SMP. That discrepancy is of particular concern to PIO because the key goal of the SMP should be to remove the dangerous, leak-prone pipeline that remains in Chicago, not to install new pipelines with long depreciable lives that may ultimately be stranded due to electrification. PIO acknowledge the retirement of leak-prone pipeline may in most cases require the installation of a new pipeline in place of the retired pipeline, but Peoples Gas is installing 75% more pipeline than it is retiring through the Neighborhood Program, calling into question whether these incremental installations are prudent and meet the “used and useful” standard, or whether they are surplus to customers’ needs and likely to be stranded or underutilized during their service lives.
PIO therefore request that the Commission scrutinize the SMP and focus the program on effective risk reduction going forward. Specifically, PIO recommend the Commission: (1) order a new investigation of the SMP; (2) require PGL to develop and propose a metric that assesses the risk reduction accomplished by the SMP on system, segment, and neighborhood bases and supports appropriate adjustments in SMP activities; (3) direct PGL to pause any medium pressure upgrades conducted as a part of its SMP Neighborhood Program until after the Commission completes its investigation of the SMP; and (4) disallow SMP costs that will not be placed in service in 2024 totaling $5,311,072.

In addition to these recommendations described above, PIO recommend the Commission adopt the AG’s adjustment to disallow $62.5 million in SMP costs from PGL’s proposed plant additions.

PIO assert that PGL, not the intervenors, bears the burden to demonstrate through the preponderance of record evidence that its investments are prudently incurred, used and useful, and just and reasonable. 220 ILCS 5/9-201(c), 9-211, 9-212; 5 ILCS 100/10-15. PIO assert that PGL has not explained why it installs significantly more pipe than it retires through a program that is ostensibly aimed at removing dangerous pipe and has therefore failed to meet its burden. Rather than clarifying its approach to the Neighborhood Program, including its decision to install more pipeline than it retires, PGL insists the Commission has previously reviewed its approach to the SMP. PIO maintain that PGL ignores, however, that the prudence of its proposed additions to rate base associated with the SMP—including the costs of pipeline installed through the Neighborhood Program — are squarely at issue in this case. PGL’s practice of installing more pipeline than it retires through the SMP, therefore, goes to the prudence of its plant additions. Given that PGL has failed to support the reasonableness of its practice through record evidence, PIO agree the Commission should adopt the AG’s proposed $62.5 million disallowance.

(v) Commission Analysis and Conclusion

The Commission notes the AG proposal disallows $62.5 million of the SMP work from rate base because Peoples Gas has installed more gas mains than it has retired in the last year. This includes the $5.3 million of SMP CWIP that the AG is challenging. The AG’s SMP CWIP challenge is discussed separately in Section IV.B.2. of the Order. Thus, the non-CWIP SMP work considered for disallowance is $57.2 million. The AG argues most utilities install a comparable amount of main that is retired in these types of projects. Both the City and PIO support the AG’s argument for disallowance.

In addition to supporting the AG’s disallowance, PIO recommend the Commission: (1) order a new investigation of the SMP; (2) require PGL to develop and propose a metric that assesses the risk reduction accomplished by the SMP, on system, segment, and neighborhood bases, and supports appropriate adjustments in SMP activities; (3) direct PGL to pause any medium pressure upgrades conducted as a part of its SMP Neighborhood Program until after the Commission completes its investigation of the SMP; and (4) disallow SMP costs that will not be placed in service in 2024, totaling $5,311,072.

The City requests the Commission direct PGL to conduct a Joint Feasibility Assessment of a portion of its service territory as part of any SMP reevaluation. Part of
the City’s request includes directing PGL to work with the City and other interested and affected stakeholders to assess the potential for strategic electrification and retirement of leak-prone pipe. The City notes this new proceeding should also analyze the costs and benefits associated with the SMP and whether all aspects of the SMP, such as the pace and cost of moving meters from the inside of customers’ premises to the outside, are still warranted.

PGL explains it is not unusual to install more pipe in one year and then retire the old pipe in the following year. PGL also notes that an element of the SMP is “double decking” which includes laying pipe on either side of a street, versus a single pipe, where it is less expensive or preferred from an engineering perspective. According to the Company, the AG never followed up to determine if there was a reason for the discrepancies between the installed and retired mains.

The Commission has considered the record, including proposals by the AG, PIO and the City, and the Company’s evidence supporting the 2024 SMP test year spending. The Commission finds the record in this case supports another course of action.

PGL asks the Commission to approve $265 million in the 2024 test year to continue funding its SMP (referred to as both “System Modernization Program” and “Safety Modernization Program” throughout the record). When prompted to explain the reason for the project, PGL referred to its revised Schedule F-4, which provided the following: “[m]aintain safety and reliability, Safety Modernization Program approved most recently in Docket 16-0376. Supported by 2020 engineering study from Kiefner Engineering [the ‘Kiefner Study’], Docket 18-1092.” PGL-NS Ex. 14.05 at 1. In response to whether alternatives were considered, PGL provided: “Not Applicable. The Commission most recently approved PGL’s approach to the SMP in Docket 16-0376, and it was further supported by the 2020 engineering study from Kiefner Engineering, submitted in Docket 18-1092, which recommended continuing accelerated replacement of cast and ductile iron [CI/DI] mains in Peoples Gas’ distribution system.” Id. The Commission shall evaluate the SMP’s test year costs for prudence and reasonableness according to the record evidence.

In Docket 16-0376, the Commission approved PGL’s neighborhood approach, but made clear:

the Commission makes no determination regarding the prudence, justness, and reasonableness of costs incurred by the Company in carrying out the SMP plan. The Commission finds that any determination concerning the prudence, justness and reasonableness of costs related to the SMP will be determined in subsequent Rider QIP reconciliation proceedings or in a future rate case.

Final Order, Docket No. 16-0376 at 160. The Commission has not determined the reasonableness or prudence of the costs associated with the 16-0376 neighborhood approach. Moreover, the legal framework, which provided PGL with concurrent cost recovery for all aspects of the SMP over the past decade, has changed. The Qualifying Infrastructure Plant (QIP) provision for gas utilities – 220 ILCS 5/9-220.3 – will sunset at the end of 2023. PGL “[filed] this rate case because it is not pursuing an extension of the
2011 law that created the Qualifying Infrastructure Plant (‘QIP’) rider.” PGL Exhibit 1.0 at 3. The Commission will review PGL’s Rider QIP annual reconciliations (for 2016, 2017, 2018, 2019, 2020, 2021, 2022 and 2023) in separate pending or anticipated cases. PGL’s proposed 2024 test year investment is not subject to QIP. The present docket – 23-0068 and 23-0069 (cons.) – is the Commission’s first comprehensive assessment of the reasonableness and prudence of costs associated with SMP following the Commission’s decisions in 16-0376 and 18-1092.

According to the Company, SMP’s purpose is to “accelerate the pace of replacing aging, at-risk components of Peoples Gas’ natural gas delivery system . . . that began with the Accelerated Main Replacement Program (“AMRP”) in 2011…consistent with PHMSA’s 2011 ‘Call to Action’.” Final Order, Docket No. 16-0376 at 3. After 12 years of work, PGL has completed “about 35% of the SMP as of October 2022, and the program will ultimately replace over 2,000 miles of pipe and improve the long-term safety and reliability of the natural gas delivery system by converting the system from low to medium pressure, moving meters outside, and installing safety equipment.” PGL Ex. 1.0 at 8-9. SMP has focused on replacing aging and at-risk pipeline (mostly CI/DI), relocating meters and re-pressurizing the distribution system, all of which were explicitly allowed under the QIP Rider statute. 220 ILCS 5/9-220.3(1)-(3). Since the Commission’s 2018 decision in Docket 16-0376, PGL used a neighborhood-by-neighborhood approach to implement SMP. Given the risks posed by the CI/DI pipe remaining within PGL’s distribution system, the Commission is concerned with PGL’s management of this project overall and its prioritization of pipeline replacement.

On April 17, 2023, while the evidentiary record was open, Commissioners submitted questions to the Companies. Considering PGL’s intention to continue SMP after QIP sunsets, Commissioners asked, in part:

a. Provide a completion timeline and cost estimate separately for each of the following activities:
   i. Replacement or retirement of remaining Cast Iron/Ductile Iron pipe,
   ii. accelerated leak reduction,
   iii. relocation of meters from inside customers’ facilities to outside, and
   iv. upgrading of the gas distribution system from a low pressure to a medium pressure system.

b. What are alternatives to Peoples’ current neighborhood model? Include benefits and drawbacks to each alternative.

Commissioners’ Questions at 1-2. PGL did not provide disaggregated cost and timeline estimates as requested. PGL instead repackaged information it previously entered in its rate case petition and older dockets. Nonetheless, the Commission has carefully reviewed the information and data that are in the record.

In response to Commissioners’ questions, PGL reminded the Commission that “[t]he Burns & McDonnell ‘Program Level Cost Forecast and Schedule Model’ report, dated November 30, 2015, (the ‘Burns & McDonnell Report’), provides the last comprehensive study of the overall completion timeline and cost estimate for the SMP.”
Interrogatory Response to Request No. ICC 1.05 at 1. PGL explained that the 8-year-old report “considered two potential completion dates – 2030 and 2040 – and based on those dates estimated overall project costs ranging from $6.83 billion to $7.81 billion under the target case to $8.33 billion to $9.69 billion under the high contingency case.” Id. PGL referred Commissioners to Docket 16-0376, completed in 2018, wherein “Peoples Gas provided an overall completion target date of 2035 to 2040…consistent with the recommendations of [the federal Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (‘PHMSA’)] ….” Id.

PGL also referred the Commission to Docket 18-1092, a 2018 engineering review of PGL’s CI/DI pipeline system. The primary outcome of that docket was the “Kiefner Study,” which “primarily focused on safety and risk and did not evaluate logistical or financial constraints that could be necessary to support an acceleration of the SMP program.” ICC 1.05 Attach02 PGL at (ii). The Kiefner Study identified the timeline within which PGL should retire all existing CI/DI pipe, irrespective of the other modernization activities PGL has undertaken in tandem with pipe retirement. The Study recommended that all CI/DI pipes be replaced by 2030 (10 years earlier than the current plan of completion by 2040), “based on the analysis of the remaining life of PGL’s CI and DI inventory, and to hold paramount the public safety and welfare through the reduction of leaks and/or failures.” Id. The Kiefner Study further recommended that pipeline replacement efforts “should be accelerated as more than 80% of the remaining cast and ductile iron pipes in Peoples Gas’s system have a remaining life of less than 15 years” with most remaining cast iron mains averaging over 90 years old and most of the remaining ductile iron mains averaging over 50 years old. PGL Ex. 1.0 at 9. Thus, the Study “concluded that ‘the replacement rate has not been fast enough to compensate for the increase in failure rates expected from the aging system.’” Id. The Kiefner Study is the primary authority on prioritizing PGL’s CI/DI retirement, and it recommended (in 2020) that PGL accelerate its efforts to retire CI/DI by 2030.

The record lacks sufficient detail regarding CI/DI pipeline replacement to find PGL’s SMP 2024 test year investments are prudent and reasonable. PGL’s SMP 2022 4th Quarter Report identifies 1,563 miles of CI/DI pipeline and low-pressure mains that PGL still intends to retire and replace through SMP. PIO Verified Reply to Commissioners’ Question 5 at 2. According to this Report, at the end of 2018, PGL had approximately 1,800 miles of identified CI/DI pipeline and low-pressure mains to replace. PGL’s SMP 2022 4th Quarter Report ([2022 - Q4 SMP Report.pdf](http://example.com)) at 6. Accordingly, between the end of 2018 and the end of 2022, PGL retired and replaced 237 miles or 59 miles per year. At this rate, it will take 26 years – until 2049 – to replace the existing high-risk pipe. PGL makes no attempt in this record to explain the steps they will take to complete retirement within or close to the Kiefner Study’s specified timeline. To the contrary, PGL stated that “accelerating the SMP to be completed on [the Kiefner Study’s] timeframe would present practical challenges,” but provided no disaggregated information the Commission could use to make an informed decision regarding ways to practically meet the recommended CI/DI retirement timeframe. Interrogatory Response to Request No. ICC 1.05 at 2.

The Commission notes that PGL did not provide SMP spending information to date or explain how the Company developed the $265 million 2024 test year amount. PGL did provide QIP spending between 2016 and 2022. PGL Ex. 3.2. Over this period, PGL spent
$1.989 billion through the QIP rider, with an annual average of $248.7 million. See Id. Narrowing the analysis to 2018 through 2022, PGL spent $1.591 billion, with an annual average of $265 million. See Id. This average appears to be what PGL used as its 2024 test year amount, though the Company did not explain how this figure was determined or why average annual QIP-level spending is prudent for SMP going forward. In support of the test year spending level, PGL references the Kiefner Study and uses the Study’s recommendation for “accelerated replacement of cast and ductile iron [CI/DI] mains” as a reason no alternatives were considered. PGL-NS Ex. 14.05 at 1. PGL invokes the Kiefner Study to demonstrate a pressing need for SMP, while declining to timely adhere to the Study’s pipe retirement recommendations. Most concerning is that PGL makes no attempt to detail and justify the SMP 2024 test year investment level to accomplish SMP’s primary objective according to the record -- to replace all CI/DI pipeline.

The Commission finds PGL has offered inadequate record justification for maintaining a $265 million spending level. PGL provided no specific justification for continuing to fund the entire SMP at the requested level. The Commission sought information to disaggregate the SMP’s components to better understand each objective’s costs and completion timeline, and to identify those components meeting statutory requirements. The Company declined to provide that information, relying instead on the eight-year-old Burns and McDonnell Report as principal supporting evidence for test year spending. PGL’s regular quarterly reports to the Commission suggest non-pipeline retirement activities in SMP are delaying the high-risk CI/DI pipe retirement. See SMP 2022 4th Quarter Report (2022 - Q4 SMP Report.pdf) at 6. For these reasons, the Commission finds PGL has not justified continuation of QIP-level spending for SMP and disallows $265 million from the 2024 test year. The Commission is pausing SMP until the Commission can determine, in a separate proceeding described below, the optimal method to replace high-risk CI/DI pipe and the prudent investment level needed to support this effort.

The Commission’s 2024 SMP test year disallowance is not intended to remove any funding from PGL related to emergency response to leaks, pipe breaks or other critically important safety measures, such as PHMSA designated grade 1 leaks. The funding level disallowed relates solely to the SMP work being conducted neighborhood by neighborhood. The Commission expects PGL to continue to address existing and new leaks as it would in the normal course of prioritizing customer safety, as confirmed by the Company in Oral Argument on November 6, 2023.

The Commission orders a new investigation of SMP. The Commission is pausing SMP until the investigation concludes. It appears neighborhood by neighborhood modernization has failed to adequately prioritize the replacement of high-risk pipe as directed by PHMSA, the Kiefner Study and the Commission. PGL’s regular quarterly reports to the Commission suggest the method of implementation, specifically neighborhood risk ranking, is not resulting in prioritizing neighborhoods with the highest levels of risk. SMP 2022 4th Quarter Report (2022 - Q4 SMP Report.pdf) at 26; See, e.g., neighborhoods ranked 20 and 21 scheduled ahead of neighborhoods ranked 1, 2, 3, 5, 7, 10 and 11. Given the urgent need to replace CI/DI pipe, the time and cost already incurred through SMP, and the sunset of QIP, the Commission will reexamine how the
Company’s neighborhood approach prioritizes high-risk CI/DI pipe retirement, through a separate SMP proceeding.

Specifically, the Commission must determine whether grouping critical safety measures with modernization measures is the most practical, cost-effective and expedient method to retire all CI/DI pipe. The Commission directs PGL to reconsider its priorities and provide more detailed, disaggregated cost information in the SMP proceeding to enable the Commission to determine the reasonableness and prudence of the Company’s next iteration of the SMP. Balancing course-correction with timely retirement of high-risk pipe, the Commission directs Staff to assist the Commission in initiating a proceeding by February 1, 2024, which should not exceed twelve months.

b. Distribution Capital Projects (NS only)

(i) Clavey Road Phase II

(a) Companies’ Position

The Companies explain that North Shore’s Clavey Road Phase II Public Improvement project (the “Clavey Road Project”) was necessary to address a conflict with the City of Highland Park’s storm sewer upsizing, reconfiguration, and road replacement project. North Shore installed 12-inch steel high pressure main and 2-inch medium pressure main and retired older main that conflicted with Highland Park’s storm sewer. See NS Ex. 3.0 REV at 30; NS-PGL Ex. 14.0 REV at 13; NS-PGL Ex. 25.0 at 13. North Shore estimated the cost of the Clavey Road Project by categorizing each cost component, including management and design, construction installation, materials, environmental, labor, and restoration; analyzing historical unit pricing; and deploying a competitive bid process. After construction began, North Shore recognized that Highland Park’s design plans, which North Shore relied upon to design its facilities, were changing and contained errors. See NS-PGL Ex. 14.0 REV at 13; NS-PGL Ex. 25.0 at 15.

Among other changes, North Shore had to bury its pipe deeper than originally planned to avoid Highland Park’s facilities. See NS-PGL Ex. 14.0 REV at 13. The scope changes and associated additional costs were necessary to address conflicts with Highland Park’s project and could not have been anticipated. See NS-PGL Ex. 25.0 at 16. Furthermore, as detailed by PGL witness Eldringhoff, North Shore employed cost control measures to limit scope changes to only those necessary to complete the project as cost-effectively as possible. NS Ex. 3.0 REV at 31. North Shore seeks to recover $3.9 million, which is the final cost of the Clavey Road Project. NS-PGL Ex. 25.0 at 18; NS-PGL Ex. 14.01.

AG witness Walker urged the Commission to disallow $1.7 million of the Clavey Road Project’s cost without providing any evidence to support disallowance of any specific components of that cost. See AG Ex. 7.0 at 13. Instead, Mr. Walker applied a generic benchmark to project costs using a base cost from an April 2017 study by the American Petroleum Institute called “Oil and Gas Infrastructure Investment through 2035” (the “API Study”). He then used a regional uplift and an inflation escalator to adjust this base cost to derive a benchmark cost for the Clavey Road Project. AG Ex. 3.0 at 55–56. Mr. Walker proposed to disallow the difference between the actual cost of the project and
his benchmark cost, reasoning that “costs in excess of the benchmark ... appear unreasonable.” Id. at 56; see also AG Ex. 7.0 at 13.

The Companies opine that using a benchmark method to calculate the cost of a gas utility's system improvement project should be viewed with suspicion due to the inaccuracies inherent in benchmarking and the individual complexities that arise in any given project. Using a benchmark is particularly inappropriate where, as here, the project is completed and its actual costs are known. See NS-PGL Ex. 14.0 REV at 15; NS-PGL Ex. 25.0 at 16. Ms. Eldringhoff testified that while benchmarking is useful to aid in forecasting costs, any benchmark must be adjusted to account for final, known information. NS-PGL Ex. 25.0 at 16–17.

While Mr. Walker has conceded that “there are potentially costs that may be prudently incurred above and beyond the benchmark ... [f]or example, if a transmission pipeline encountered a body of water or long stretches of shallow bedrock” (AG Ex. 7.0 at 7), he seemingly does not analogize this to unanticipated costs associated with a depth redesign caused by Highland Park, as occurred on the Clavey Road Project. However, according to Ms. Eldringhoff, these circumstances are similar and represent the various unknown circumstances that can arise with underground construction activity. NS-PGL Ex. 25.0 at 15. It is unreasonable for Mr. Walker to treat an unknown geological condition differently from an unknown design change or an unexpected field condition as they all would have the same effect of changing the installation of a pipeline, and impact project costs. Id.

Furthermore, because the API Study’s base cost is a national average, it is not accurate for a utility’s specific geographic region due to regional variations in the costs of materials and labor. Despite Mr. Walker’s belief that the 20% regional modifier is a “generous addition” that “accounts for the varying costs of materials and labor” (AG Ex. 7.0 at 9), it remains unclear how such an adjustment considers the complexities of construction projects in urban areas versus rural areas in the same geographic region that includes much of the Midwest, urban and rural, let alone accounts for the unique challenges of the Clavey Road Project. NS-PGL Ex. 25.0 at 17.

The AG argued in its Initial Brief that “North Shore has not provided sufficient evidence demonstrating that the additional costs incurred were unavoidable or otherwise prudently incurred.” AG IB at 18. This assertion simply ignores the evidence North Shore provided in the case. North Shore provided extensive testimony showing that it appropriately estimated the initial cost of the Clavey Road Project by categorizing each cost component, including management and design, construction installation, materials, environmental, labor, and restoration; analyzing historical unit pricing; and deploying a competitive bidding process. NS-PGL Ex. 14.0 REV at 16. Beyond this, North Shore’s direct testimony explained how North Shore controlled capital costs through cost saving initiatives, such as using industry best practices for construction, and through its contracting function, which awards construction contracts through a competitive bidding process and lets jobs using a unit-based pricing approach to mitigate the risk of cost overruns. NS Ex. 3.0 REV at 9–10. Ms. Eldringhoff also explained the nature of the mid-project changes and resulting cost overruns in detail. Specifically, she addressed how (1) Highland Park revised its sewer main design, installing it deeper than originally designed for 875 feet of its length; (2) a water main in the same area was deeper than
shown on drawings for 1,000 feet, also requiring the gas main to be installed deeper than
planned; and (3) a temporary storm sewer leaked heavily into the gas pipe tie-in opening,
which required continuous draining. Ms. Eldringhoff testified that these issues “could not
have been anticipated.” NS-PGL Ex. 14.0 REV at 13–14; NS-PGL Ex. 14.01. The AG
did not respond to any of this evidence, and instead just repeated its refrain that the
Clavey Road Project costs “far and away exceed the industry benchmark presented by
Mr. Walker.” AG IB at 19.

The AG points to the Commission’s recent decision in the Northern Illinois Gas
Company d/b/a Nicor Gas Company’s (“Nicor Gas”) QIP reconciliation proceeding where
the Commission held that each project is subject to a prudence review and should stand
on its own merits. AG IB at 19 (citing N. Ill. Gas Co. d/b/a Nicor Gas Co., Docket No. 20-
0330, Order at 26 (June 15, 2023). This holding is unremarkable; it does not establish a
new legal principle. North Shore was required to make a prima facie showing of prudence
and did so. While the AG emphasizes the Commission’s finding in Nicor Gas’ QIP case
that poor due diligence during project design could indicate imprudence, that is not the
case here. Necessary mid-project scope changes were identified only after construction
began and were due to inaccuracies in Highland Park’s design plans, not North Shore’s
plans. The AG provides no evidence that North Shore’s pre-construction diligence was
lacking in any way.

In summary, where the final cost of a construction project is known, that
information should be used instead of attempting to derive the cost from a generic
benchmark. Mr. Walker provided no evidence to support disallowing any specific
components of the project costs beyond his general assertion that costs in excess of his
generic benchmark were imprudently incurred. The Companies conclude that the
Commission should reject his proposed disallowance and allow North Shore to recover
the full cost of the Clavey Road Project.

(b) AG’s Position

The AG asks the Commission to disallow $1.689 million for the Clavey Road
Project because North Shore failed to justify why the final cost for this project substantially
exceeded the cost benchmark for industry construction. North Shore also failed to prove
why the changes to scope and costs resulting from changes and errors in Highland Park’s
design plans could not have been anticipated.

Mr. Walker compared North Shore’s proposed transmission construction costs to
an industry standard benchmark and found the Clavey Road Project Phase 2 to be
substantially and unjustifiably in excess of the industry pipe replacement benchmark. AG
Ex. 7.00 at 13. Mr. Walker also analyzed North Shore’s MAOP reconfirmation budget
and processes and found them to be generally reasonable; however, he testified that the
Commission direct North Shore to “formalize its plans into a MAOP & Records
Compliance Plan for implementing the MAOP reconfirmation … and that it continue[ ] to
use least-cost practices to confirm MAOP and missing records in the meantime.” AG Ex.
3.00 at 54.

The record does not support the high cost of the Clavey Road Project. According
to North Shore, the Clavey Road Project involves the replacement and relocation of 2,450
feet of 12-inch steel high pressure main and 1,115 feet of 2-inch medium pressure main,
for a total of 3,565 feet or 0.68 miles on a tree-lined suburban street, at a cost of approximately $3.8 million. NS Ex. 14.0 REV at 13; AG Ex. 7.00 at 8-9.

AG witness Walker assessed the reasonableness of North Shore’s proposed cost by performing an industry-standard analysis of pipeline construction costs and comparing North Shore’s construction costs for this project to his findings. See AG Ex. 3.00 at 55–56; AG Ex. 7.00 at 11–12. Based on the diameter sizes of this pipeline project, Mr. Walker used the base cost per Dia-inch-Mile constant of $178,000 as the appropriate benchmark. AG Ex. 3.00 at 55; see also AG Ex. 7.00 at 12, fn.16 (using the weighted average cost of the two pipe diameters). Generally, North Shore complained that Mr. Walker’s benchmark analysis “did not reflect the conditions and requirements specific to the Clavey Road Project or the unique characteristics of North Shore’s distribution system, such as age, condition, location, and size.” NS Ex. 14.0 REV at 15.

To address North Shore’s complaints, Mr. Walker added a regional cost and inflation escalator to arrive at a revised cost per Dia-inch-Mile constant of $274,551; this represented an increase of 5% over the prior benchmark Mr. Walker calculated. Id. at 11. Mr. Walker used data procured from the Oil and Gas Journal (“OGJ”) and the United States (“U.S.”) Energy Information Administration’s (“EIA”) in June of 2023; this is the most current data that was available from these sources. AG Ex. 7.00 at 10–11. The AG notes that this new data set includes more specific information on the nature of the projects considered in the benchmark (Id. at fn.13, 14), notwithstanding the fact that Mr. Walker already accounted for project conditions and locational variables in his original analysis by adopting the API’s generous regional cost uplift of 20%. Id. at 9, 12. Mr. Walker then recalculated the project cost ($2.13 million) and compared it to the proposed project cost ($3.82 million). AG Ex. 7.00 at 13. Even accounting for North Shore’s identified variables, Mr. Walker testified that PGL’s cost for the Clavey Road Project was still $1.689 million above the benchmark.

Mr. Walker explained that this cost is excessively high even for an urban project, despite the fact that Clavey Road rests on the outskirts of the city, on a residential street. Id., see also AG Ex. 7.00 at 9. Mr. Walker testified that while benchmarks are not a “to-the-dollar” gold standard of the cost of every specific project, they serve as a guideline for generalizing costs that are being incurred across the industry. AG Ex. 7.00 at 12. The AG asserts that North Shore has not provided evidence to demonstrate the additional costs incurred were unavoidable or otherwise prudently incurred. Id.

North Shore complains that “using benchmark data to disallow construction costs is inappropriate when actual costs are known.” NS Ex. 14.0 REV at 15. However, according to the AG, North Shore’s mere presentment of actual costs cannot establish whether its spending is prudent or reasonable. The AG highlights that in addition to exceeding a reasonable benchmark, there is a 68% cost variance between the budgeted amount and actual cost incurred on this project. The AG notes the original cost estimate for this project was $2.28 million (AG Ex. 7.00 at 8), but North Shore not only exhausted its $592,000 (or 30% contingency), but also incurred nearly $1 million in overages, which brought the total cost of the Clavey Road Project to $3.82 million. Id. at 8, 12.

The AG iterates that the Commission determined that projects and their budgets must stand on their own merits in a recent QIP reconciliation proceeding involving Nicor
Gas, Docket No. 20-0330. In this matter, the Commission ordered multiple disallowances. See, e.g., Docket No. 20-0330, Order at 41–43, 50–52. In doing so, the Commission stated that “each project is subject to a prudence review and should stand on its own merits …” and while “projects are not per se imprudent or unreasonable just because there is a cost variance … causes, frequency, or size of variances can be evidence relevant to a determination of prudence.” Id. at 26, 34. North Shore, however, wrongly expects its presentation of actual project costs alone to justify the efficacy of its project design, construction, and cost controls. See AG Ex. 7.01. Based on the Commission’s recent decision in Docket No. 20-0330, the AG argues that North Shore’s position is untenable.

North Shore further complains the cost increases were unforeseeable. The AG asserts that none of the circumstances North Shore points to justifies the nearly $1.689 million in excess costs to ratepayers. The AG argues that these circumstances only further show North Shore’s lack of due diligence and inadequate management.

First, the AG notes that North Shore asserted that “after construction began, [it] recognized that Highland Park’s design plans … were changing and contained errors.” NS/PGL IB at 23. The AG argues that a multi-million-dollar project such as the Clavey Road Project cannot be designed and built in a single day. They contend that it requires significant planning, designing, and coordination over time and well in advance of any actual work being started. See, e.g., NS/PGL Ex. 14.0 REV at 23. Accordingly, the AG argues that, by any measure, North Shore’s statement that it uncovered changes and errors “after construction began” is unacceptable. The AG contends that North Shore failed to provide the critical timeline of the project, project design, permit review milestone dates, and descriptions or dates of the alleged changes or errors which might justify why it did not discover “changes and errors” until so late in the project. The AG avers that this lack of justification demonstrates a lack of due diligence and poor management, as well as a blind eye toward regulatory accountability. The AG urges the Commission not to reward such performance, or more accurately, the lack thereof.

The AG again cites to Docket No. 20-0330 noting that the Commission found certain costs to be imprudent because “the Company submitted no evidence … of discussions with the municipal officials or an analysis demonstrating that delays, delay costs, and additional materials and labor costs were contemplated and compared to reasonable project alternatives.” Docket No. 20-0330, Order at 51. The Commission explained that “[e]ffective coordination with municipalities and impacted businesses for the installation of a major gas pipeline project is a reasonable and basic expectation of a natural gas distribution company in their planning process.” Id. The AG asserts that the Commission should reach the exact same conclusion here because North Shore similarly failed to perform its due diligence to coordinate with local officials and has offered no justification for why it learned of errors and changes after construction began.

Second, the AG contends North Shore’s contention that a water main being found to be closer to the new gas main than shown on plans was unforeseeable is meritless for the same reason: its lack of due diligence. The AG argues that North Shore again provides no justification besides its statement that this was allegedly out of its control. NS/PGL Ex. 14.0 REV at 13. In Docket No. 20-0330, the AG notes that Nicor Gas requested recovery for an underground project for “which it did not know the extent” of
field conditions for “an existing saline pit, pit liner, and drip/syphon piping.” Docket No. 20-0330, Order at 42. In effect, the utility argued that for underground facilities, “exact underground conditions may not be fully known until excavation,” and that the associated costs were thus unforeseeable. Id. at 41. The AG points out that the Commission disagreed, stating “just because a facility is underground does not mean it is per se unforeseeable” and that it was Nicor Gas’ “responsibility to have accurate records on the location and the depth” of the facilities provided the “several engineering methods of identifying sub-surface facilities.” Id. at 42. The AG asserts that North Shore’s failure to utilize effective engineering methods to determine sub-surface facilities and have accurate records of the site mirrors Nicor’s failure and was similarly not unforeseeable.

Third and lastly, the AG contends that North Shore offers no justification why a temporary storm sewer’s failure was unforeseeable. The AG highlights that North Shore declined to state who installed the temporary sewer, why it was installed, who was responsible to maintain it while in operation, whether its failure was the result of poor craftsmanship or damage sustained during excavation, or whether some other factor caused it to leak into North Shore’s tie-in area. The AG avers that by any measure, North Shore cannot satisfy its burden of proof that any of these circumstances were unforeseeable given its failure to provide even the most basic facts to explain the presence of the temporary sewer. The AG asserts that it is not the Commission’s nor the AG’s duty to reverse-engineer North Shore’s project to determine whether it or its contractors breached their duty of care, but North Shore’s duty to provide sufficient evidence to try to explain or excuse its actions or inactions.

In short, the evidence does not support cost recovery for North Shore’s Clavey Road Project. The AG asks the Commission to disallow $1.689 million from North Shore’s proposed transmission costs for the Clavey Road Project.

(c) Commission Analysis and Conclusion

The Commission agrees with the AG that the use of a benchmark is a standard, tested method for reviewing project costs for reasonableness and is a valuable check on both budgeted and incurred costs. AG witness Walker states that his benchmark accounted for variables raised by the Company. See AG Ex. 7.00. The AG also demonstrated a 68% cost variance between the budgeted and actual cost incurred for the Clavey Road project. North Shore used its $592,000 budgeted contingency and incurred an additional nearly $1 million in overages, bringing the total cost of the project to $3.82 million. AG Ex. 7.00 at 8. The AG notes the Clavey Road variance exceeded the budgeted amount by $1.54 million, which is commensurate with Mr. Walker’s benchmark disallowance of $1.689 million. AG IB at 18. North Shore argues Highland Park changed the design plans the Company relied upon to design its facilities and argues other issues encountered in the field were unforeseen and could not have been anticipated. See NS-PGL Ex. 14.0 REV.

North Shore did not provide the timeline of the project, project design, permit review milestone dates, or descriptions or dates of the alleged changes or errors to justify its assertion that the additional costs were unavoidable, unforeseen, and out of the Company’s control. Id.; see also NS Ex. 3.0 REV. The Company must provide sufficient evidence to explain that its actions and decision-making were prudent. For example, the
Company fails to satisfy its burden of proof in providing basic information about the temporary storm sewer’s failure, such as who installed it and why and what caused the failure. See NS/PGL Ex. 14.0 REV.

The Commission finds North Shore did not provide sufficient evidence demonstrating the additional costs identified by the AG were unforeseeable or prudently incurred. Mr. Walker’s benchmark analysis further supports the AG’s contention that the identified costs are excessive. The Commission adopts the AG’s proposed disallowance of $1.689 million, which was derived from its benchmark and is commensurate with the variance amount.

c. Transmission Capital Projects (PGL only)

(i) MAOP Reconfirmation Project

(a) Companies’ Position

The Companies explain that the PHMSA MAOP Rule is intended to improve the safety of natural gas pipelines and was the primary federal regulatory response to a 2010 natural gas pipeline explosion that occurred in San Bruno, California, which killed eight people and resulted in billions of dollars in damages and fines. NS-PGL Ex. 14.0 REV at 30. At a very high level, the rule seeks to confirm that transmission pipelines can withstand the pressure of the gas they carry through hydrostatic pressure testing, replacement, or materials verification, with the ultimate goal of avoiding a catastrophic rupture. NS-PGL Ex. 14.0 REV at 30.

While acknowledging that Peoples Gas is not seeking to include any MAOP reconfirmation projects in rate base (and therefore not recommending any specific rate base or revenue requirement disallowance), PIO witness Cebulko, apparently looking beyond the test year, recommends that the Commission require Peoples Gas to evaluate: (1) each of the six MAOP reconfirmation methods for all future MAOP rule investments and demonstrate, with sufficient quantitative analysis, that its decision will result in the least-cost, least-risk solution; and (2) the cost effectiveness of deploying non-pipeline alternatives (“NPAs”) in combination with derating pipelines (reconfirmation of method 2 and 5). PIO Ex. 1.0 at 35. The MAOP Rule provides for reconfirmation using one of the following methods: (1) pressure test; (2) pressure reduction; (3) engineering critical assessment; (4) pipeline replacement; (5) pressure reduction for pipeline segments with small potential impact radius; and (6) alternative technology. PIO Ex. 1.0 at 32. Mr. Cebulko claims such an approach is needed due to the “capital bias inherent in traditional utility regulation” that incentivizes utilities to reconfirm pipelines through replacement versus another method. Id. at 34. Mr. Cebulko’s characterization of Peoples Gas’ reconfirmation approach, which suggests that the Peoples Gas is attempting to replace substantially all pipeline segments in need of confirmation without any substantive analysis or consideration of alternative methods, is plainly untrue.

Under the MAOP Rule, operators are required to reconfirm the MAOP of all transmission pipelines that meet specific criteria. NS-PGL Ex. 14.0 REV at 30–31 (citing 49 C.F.R. § 192.624). Reconfirmation must be performed using one of six methods and the rule provides for several compliance deadlines for reconfirming MAOP, including that operators were first required to develop MAOP reconfirmation procedures by July 1, 2021,
and that operators are further required to perform MAOP reconfirmation for at least 50% of covered pipeline mileage by July 3, 2028, with complete MAOP reconfirmation by July 2, 2035, or four years from the date that a segment becomes subject to the regulation, whichever is later. NS-PGL Ex. 14.0 REV at 31.

As a threshold matter, Mr. Cebulko mistakenly believes that two-thirds of Peoples Gas’ transmission system, which would mean approximately 222 miles, was installed before 1980 and thus requires reconfirmation. PIO Ex. 1.0 at 33. According to PGL witness Eldringhoff, the actual amount requiring reconfirmation is much lower, constituting approximately 2.25 to 5 miles of the transmission system. NS-PGL Ex. 14.0 REV at 32; NS-PGL Ex. 14.02. Peoples Gas took steps during the reconfirmation planning phase to reduce the scope of pipeline segments requiring reconfirmation, including by reducing pipeline pressures and refining location data, prior to and after the July 2021 regulatory enforcement deadline. For the resulting limited amount of transmission main subject to the MAOP Rule, Peoples Gas has, in fact, analyzed all six reconfirmation methods, with the overall goal of utilizing the most cost-effective reconfirmation methods that will ensure the safe operation of the transmission system. NS-PGL Ex. 14.0 REV at 32–33; NS-PGL Ex. 14.03. This analysis indicated that the two most viable methods for achieving compliance with the MAOP Rule are Method 1 – Pressure Test and Method 4 – Replacement and demonstrated why the other four methods are unfeasible at this time. Id. With respect to PIOs’ proposal that Peoples Gas focus on Method 2 – Pressure Reduction, Peoples Gas has already pursued that method by reducing the pressure in significant portions of its system, thereby reducing the amount of pipe that will need to be addressed through other methods. Id.

Mr. Cebulko’s second recommendation appears to be requiring NPAs as a supplement to reconfirmation methods 2 and 5, with a focus on reducing demand on a long-term basis to decrease the need for gas supply and thus enable MAOP reconfirmation through pressure reduction. If this understanding is accurate, then Mr. Cebulko’s recommendation is somewhat misguided. This long-term recommendation fails to account for the compliance deadlines set by the MAOP Rule, including 50% reconfirmation by 2028 and 100% reconfirmation by 2035, and the urgency conveyed by PHMSA to take immediate actions to ensure pipeline safety. NS-PGL Ex. 14.0 REV at 33–34. MAOP segment qualification is driven by a multitude of factors outlined in the PHMSA regulations, which can eliminate pressure reduction as a viable method of reconfirmation. Id. at 34. While Peoples Gas appreciates Mr. Cebulko’s sensitivity to increased customer costs, PGL’s reconfirmation strategy appropriately balances that concern with safety and reliability. Id. Lastly, it is noteworthy that NPAs are not among the six reconfirmation methods that PHMSA allows; PIO neither attempts to address this discrepancy nor offers any specifics about what NPAs might look like in the context of a reconfirmation project. Accordingly, the Commission should reject Mr. Cebulko’s second recommendation, as it could lead to MAOP Rule non-compliance and fails to sufficiently account for customer safety considerations.

Lastly, as discussed in greater detail in Section IV.B.5.b, PIOs’ recommended approach to MAOP reconfirmation would impact multiple utilities. While Mr. Cebulko’s recommendations are unlikely to increase safety or more efficiently achieve PHMSA compliance, opening a dedicated docket to examine the merits of his recommendations
would at least lead to greater consistency across Illinois utilities, provide for better input from the Commission’s Office of Pipeline Safety and PHMSA, and reduce the administrative burdens on the Commission that would otherwise result from developing MAOP reconfirmation requirements in multiple separate utility dockets.

AG witness Walker recommends that North Shore formalize its MAOP compliance plan; continue to use least-cost practices for MAOP reconfirmation, including providing alternative analyses to the extent replacement is pursued; and demonstrate consistency with the compliance plan for each request for cost recovery. AG Ex. 3.0, 54. North Shore takes no issue with Mr. Walker’s recommendations to the extent that they permit North Shore to pursue MAOP reconfirmation with the overall goal of utilizing the most cost-effective reconfirmation method that ensures the safe operation of the transmission system. NS-PGL Ex. 14.0 REV at 36.

(b) AG’s Position

AG witness Walker’s analysis of North Shore’s reconfirmation budget and activities revealed that North Shore has “identified all segments of transmission pipe that require MAOP reverification, put together a preliminary plan for remediation that stretches out the work over the compliance period, and relies heavily on pressure testing.” AG Ex. 3.00 at 53. Mr. Walker also testified that North Shore is utilizing material sampling and destructive testing as well as selective equipment replacements to confirm material properties — all without wholesale replacement. Id. at 54. He concluded that “this approach is generally reasonable,” and recommended that North Shore should formalize its practices in a MAOP & Records Compliance Plan. Id.

The AG asks the Commission to adopt Mr. Walker’s recommendation. The AG states that this plan should identify specific ways in which North Shore will utilize opportunistic sampling, regular integrity assessments, and other means of reconfirming MAOP and verifying records across the two compliance periods of now-2028 and 2028-2035. The AG recommends North Shore demonstrate in its plan how it is following the PHMSA directive to take a least-cost opportunistic approach to verifying materials and reconfirming MAOP. To the extent that North Shore believes that replacement is the only option or the most cost-effective option for certain segments, the AG recommends it should include a thorough alternatives analysis for each alternative method for compliance including cost and operational feasibility considerations. The AG avers this plan will ensure that compliance is reached in the required increments while allowing for maximum cost efficiency by utilizing existing and lower-cost activities. In addition to the MAOP and Records Compliance Plan, the AG argues each request for capital recovery for compliance work in connection with the MOAP Rule should be accompanied by a demonstration of consistency with the plan on a per-project basis. According to the AG, this will enable greater oversight, and most critically, provide the opportunity to evaluate the cost effectiveness of the method proposed to ensure North Shore takes the least-cost approach to MAOP reconfirmation.

(c) PIOs’ Position

PIO note that Peoples Gas did not propose any reconfirmation projects in this rate case, but PGL will need to reconfirm MAOP for approximately 2.25-5 miles of transmission pipeline in the future. NS-PGL Ex. 14.0 at 32. To ensure Peoples Gas’
reconfirmation efforts do not exacerbate bill increases and the risk of stranded assets, PIO explain that Peoples Gas should rigorously examine all reconfirmation alternatives. PIO note Peoples Gas has identified Method 1 – Pressure Test and Method 4 – Replacement as “The two most viable methods to achieve PHMSA compliance.” *Id.* at 32-33. Pipe replacement is a particularly expensive reconfirmation method that generates risk of stranded assets, however, and PGL should diligently examine less costly alternatives first. Electrification risks stranding the costs of new transmission pipelines because those pipelines have a lifespan of over 50 years and will not fully depreciate until at least 2070. PIO Ex. 1.0 at 34. In contrast, other reconfirmation methods—such as Method 2, Pressure Reduction—do not require major infrastructure investments and therefore minimize stranded asset risk.

To ensure PGL pursues least-cost reconfirmation methods for the transmission pipeline requiring reconfirmation in the future, PIO request that the Commission direct Peoples Gas to not only evaluate each of the six MAOP reconfirmation methods for all future reconfirmation investments, but also transparently demonstrate, with sufficient supporting quantitative analysis, that its chosen reconfirmation method will result in the least-cost, least-risk solution. *Id.* at 35. In particular, the Commission should require PGL to evaluate the cost-effectiveness of deploying NPAs — activities or investments that delay, reduce, or avoid the need to build traditional gas system infrastructure, such as demand response and energy efficiency — in combination with de-rating pipelines. *Id.* at 35. That combination may offer a practical and cost-effective approach to reconfirmation where pressure reduction alone is not technically feasible given the existing load served by a transmission pipeline. *Id.* at 34. Peoples Gas witness Eldringhoff objects to Mr. Cebulko’s suggestion that PGL deploy NPAs in tandem with pressure reduction, emphasizing the “urgency conveyed by PHMSA to take immediate actions to ensure pipeline safety”, but does not explain why implementing NPAs and pressure reductions would slow down PGL’s efforts to meet the 2028 and 2035 compliance deadlines set by the MAOP Rule. Contrary to Ms. Eldringhoff’s assertions, PIO do not dispute that Peoples Gas’ reconfirmation strategy must prioritize safety and reliability, nor do PIO suggest Peoples Gas should select any particular reconfirmation method in all instances. However, in light of accelerating electrification, the affordability pressures PGL’s customers already face, and PGL’s obligation to provide least-cost service, PIO maintain that it is critical that Peoples Gas rigorously examine reconfirmation alternatives to ensure it is addressing safety and reliability as cost-effectively as possible.

(d) **Commission Analysis and Conclusion**

The AG recommends the Commission require North Shore to implement a plan that identifies specific ways in which North Shore will utilize opportunistic sampling, regular integrity assessments, and other means of reconfirming MAOP and verifying records across the two compliance periods of now-2028 and 2028-2035. The AG recommends North Shore demonstrate in its plan how it is following the PHMSA directive to take a least-cost opportunistic approach to verifying materials and reconfirming MAOP. The AG concluded that “this approach is generally reasonable,” and recommended that North Shore should formalize its practices in a MAOP & Records Compliance Plan.

PIO request that, to ensure Peoples Gas pursues least-cost reconfirmation methods for the transmission pipeline requiring reconfirmation in the future, the
Commission should direct Peoples Gas to not only evaluate each of the six MAOP reconfirmation methods for all future reconfirmation investments, but also transparently demonstrate, with sufficient supporting quantitative analysis, that its chosen reconfirmation method will result in the least-cost, least-risk solution. PIO also asks the Commission to require the cost-effectiveness of deploying NPAs and combining them with de-rating pipelines (reconfirmation methods 2 and 5).

The Commission notes that Peoples Gas is not seeking to include any MAOP reconfiguration projects in rate base. The Commission also notes that Peoples Gas has recently taken steps to reduce the scope of pipeline segments requiring reconfiguration. Peoples Gas indicates that the remaining section is such a small segment and will be analyzed in the most cost-effective method possible. Therefore, the Commission denies PIOs’ first recommendation.

The Commission finds that NPAs are not among the six reconfirmation methods that PHMSA allows, and PIO has not attempted to offer any specifics about what NPAs might look like in the context of a MAOP reconfirmation project. The Commission notes that it will be exploring the future of gas as discussed below and the recommendations of PIO and other parties can be explored further in that proceeding. The Commission therefore declines to adopt PIOs’ second recommendation.

The Commission notes that North Shore does not object to the AG’s recommendation to formalize its MAOP compliance plan; continue to use least-cost practices for MAOP reconfirmation; and demonstrate consistency with the compliance plan for each request for cost recovery. The AG recommends North Shore demonstrate in its plan how it is following the PHMSA directive to take a least-cost opportunistic approach to verifying materials and reconfirming MAOP. In addition to the MAOP and Records Compliance Plan, the AG argues that each request for capital recovery for compliance work in connection with the MOAP Rule should be accompanied by a demonstration of consistency with the plan on a per-project basis. Accordingly, the Commission directs North Shore to include a report detailing its MAOP compliance in subsequent rate increase filings to the extent it is requesting MAOP reconfirmation cost recovery. North Shore should have the report available and provide it as part of any requested cost recovery.

d. Shops and Related Facilities (PGL only)

(i) Companies’ Position

Peoples Gas states that the AG and PIO challenge its needed capital investment in several old shops and related facilities that have been or soon will be constructed in Peoples Gas’ service territory to better serve customers and provide a safer working environment for employees. AG witnesses Walker and Selvaggio, supported by PIO witness Elder, urge the Commission to defer consideration of $180.6 million in related rate base, and to disallow $31.8 million in CWIP for Peoples Gas’ South Shop. AG Ex. 1.0 at 3–4; AG Ex. 3.0 at 44–49; AG Ex. 7.0, 23–26; AG Ex. 5.01 PGL, Sch. A1, A2; PIO Ex. 7.0 at 3 (figures reflect the AG’s rebuttal position). In its Initial Brief, the AG doubled down on its proposal, arguing instead for full disallowance of the $236.2 million investment. There is no factual or legal basis for this. Peoples Gas made a prudent decision to replace aging, inefficient, environmentally contaminated, and, in some cases,
dangerous service facilities in Chicago. To the extent South Shop CWIP hinges on challenges to the prudence of the underlying investment, Peoples Gas addresses those challenges here. To the extent parties object to the amount of CWIP based on in-service dates or related accounting considerations, those challenges are addressed in Section IV.B.2.a.

Peoples Gas has three principal service shops from which it has conducted operations, maintenance, and construction activities in the City of Chicago over the past century, all of which have been replaced in recent years or will need to be by 2025. The “North Shop,” formerly located at 3955 North Kilpatrick Avenue, is now located at 4025 West Peterson Avenue. The “Central Shop,” formerly located at 1250 South Kilbourn Avenue, is now located at 4207 West 35th Place. The “South Shop” is located at 38 West 64th Place and the new shop will be built on the same site. With the exception of the North Shop, Peoples Gas located the new shops on land it already owned, in order to help control costs. PGL Ex. 3.0 REV CORR at 11.

Peoples Gas explains that the decision to have three shops rather than one is intentional and is primarily driven by safety concerns. Keeping its customers and the public safe every day is Peoples Gas’ most important goal. In light of Chicago’s geographic expanse, and the realities of traffic in a major city, having three shops strategically located in the North, Central, and South areas of Chicago allows Peoples Gas to respond faster to natural gas emergencies. Consistent with natural gas utility best practices, Peoples Gas strives to respond to natural gas leaks within 60 minutes of receiving a leak report. Id. at 12. Having multiple shops allows Peoples Gas to provide better customer service by offering more appointments due to reduced travel times. Also, having multiple shops saves on Operations and Maintenance (“O&M”) by increasing the life of Peoples Gas’ fleet assets and reducing wear and tear and fleet maintenance, while also reducing fuel costs and Peoples Gas’ carbon footprint by reducing travel distances. Id. Peoples Gas has also developed other supporting facilities. Id. at 11-12; NS-PGL Ex. 19.0 at 3–4. These smaller facilities appear on PGL’s Schedule F-4 (PGL Ex. 3.1), and Peoples Gas is also seeking to recover their costs in rates. PGL Ex. 3.0 REV CORR at 12.

Peoples Gas explains that it needed to address, upgrade, and in some cases entirely replace these facilities for several reasons. All of the shops were outdated and in poor condition, due first and foremost to their age. The newest shop—the North Shop—was constructed in 1937 and the oldest—the South Shop—dates to 1906. To give some perspective on just how old the facilities are, the South Shop still contains a hay loft, which was used to store hay for the mules and horses that were used to pull carriages to conduct utility work at the time the South Shop was constructed. NS-PGL Ex. 30.0 at 2–3.

Further, Peoples Gas’ operations had outgrown several of the facilities, as those operations continued to grow along with the city’s population through many decades. The resulting overcrowding both inside and outside the facilities created inefficient and sometimes hazardous working conditions for employees. The situation was particularly acute at the North and Central Shops, where operations had physically outgrown the available land. The sites had inadequate employee parking space, forcing some employees to park remotely, and there was inadequate room to store PGL vehicles,
equipment, and material needed to service the complex natural gas system that has developed in Chicago since the shops were first built. *Id.* at 3.

In addition, Peoples Gas’ historic facilities were unevenly utilized, with much more activity in certain shops than others. In some cases, the layout of the facilities had not kept up with modern needs, resulting in inefficiencies and potentially dangerous conditions for employees. Finally, in some cases, building new shops allowed Peoples Gas to consolidate facilities that were previously spread across the City. For example, the new North Shop consolidates operations that were formerly spread across the North Shop and two other legacy facilities, Rogers Park Shop, and Division Street facilities. PGL Ex. 3.0 REV CORR at 15.

Peoples Gas worked with industry experts to thoroughly evaluate how best to address the PGL’s facility needs. First, in 2015, shortly after WEC acquired Peoples Gas and North Shore, Peoples Gas retained Mortenson Construction (“Mortenson”) to provide a comprehensive assessment of the overall condition of the Companies’ facilities. Mortenson undertook a complete review of all the major facilities owned by Peoples Gas and North Shore around Chicago and the suburbs. For each facility, Mortenson considered multiple factors, including the condition of outside areas, building envelopes, roofs, interior conditions, environmental hazards on site, energy use at the buildings, mechanical systems, and compliance with building codes. Among the issues that Mortenson considered in making a recommendation on each facility was its “adaptability” (i.e., whether it could be remodeled or refinished) to serve Peoples Gas’ needs. On this issue, each facility was given a score from 1 (“limited opportunity for re-use”) to 4 (“open flexible space”). NS-PGL Ex. 19.0 at 6–7. The North and South Shops both received scores of “1” on this metric (*Id.* at 11, 15), and the Central and Division Street Shops each received a score of “2,” indicating that they would require “Major Work to Reuse (greater than 50% of value).” *Id.* at 13 at 17.

In 2016, Peoples Gas also hired Cushman Wakefield, a national real estate brokerage firm, to further assess Peoples Gas’ facilities and make recommendations on how to structure PGL’s shop and support facilities network. Cushman Wakefield identified four goals to be pursued through the process: (1) construct a facilities portfolio that meets operational requirements and facilitates excellent customer service; (2) provide a more efficient, functional, and safe workplace; (3) provide flexibility in location and cost position to meet future customer requirements; and (4) reduce capital and O&M spending on existing facilities. Each Peoples Gas facility was analyzed for its ability to meet these goals, and Cushman Wakefield made a series of “Tier 1” and “Tier 2” recommendations for construction of new facilities and repurposing and renovating existing facilities. PGL Ex. 3.0 REV CORR at 14. Cushman Wakefield’s study exceeds 300 pages and is available in the record as part of NS-PGL Ex. 19.01.

Finally, in 2017, Peoples Gas hired McKissack & McKissack and FH Paschen to review Cushman Wakefield’s recommendations, design new operations facilities, and create budgets and construction timelines for the projects. Based on these recommendations and its own internal analysis of its current and future needs, Peoples Gas proceeded to planning for construction of new facilities in 2018. *Id.* at 14–15. These design recommendations are also available in the record as part of NS-PGL Ex. 19.01.
Both Mortenson’s and Cushman Wakefield’s findings were extensive and further confirmed the need to replace several of PGL’s facilities. Mortenson outlined an overall “master plan” based on its findings. NS-PGL Ex. 19.0 at 8; NS-PGL Ex. 19.02 at 12. Specific findings common to all the shops being replaced were that they had each been constructed on the site of former manufactured gas plants, had hosted former or current underground storage tanks, and had been used to store hazardous chemicals. In addition, each had varying levels of asbestos on site, as further described for each shop below. NS-PGL Ex. 19.0 at 8; NS-PGL Ex. 19.02 at 8.

Mortenson also made specific findings as to each of the North Shop, the Central Shop, and the South Shop, recommending that each be replaced. NS-PGL Ex. 19.0 at 9–14; NS-PGL Ex. 19.02 at 16–37, 60-76, 138-157.

Mortenson’s 2015 findings as to the South Shop are especially notable because as recently as 2012, Peoples Gas was forced to invest $160,000 in repairs at South Shop to address a long list of structural issues, including a cracked and crumbling wall, disbonded mortar joints, cracked and missing brick, broken glass block, failed sealant, and lintels separating from windows. NS-PGL Ex. 19.04 provides photos and a survey of those issues. The fact that a long list of structural defects was addressed just three years before Mortenson found the South Shop to be in such disrepair points to the rapidly deteriorating conditions at the shop and supports the need to build a new facility. NS-PGL Ex. 19.0 at 15–16.

Mortenson’s findings encompassed a number of buildings formerly located at the Division Street complex, including an office and meter shop, a warehouse, and a repair garage—all of which are now centralized at the Logistics Support Facility. The Division Street complex also housed a Field Operations group that is now housed in the new Central Business District (“CBD”) Sub-Shop. As with the North, Central, and South Shops, Mortenson found the Division Street complex to be in poor condition (score of 2.2) and recommended that it be replaced. NS-PGL Ex. 19.0 at 16.

The Cushman Wakefield study built upon Mortenson’s findings to develop a portfolio strategy focusing on the four facilities discussed above — the North, Central, and South Shops and the Division Street complex. The study sought to design a cost-effective, optimal plan for Peoples Gas’ facilities, taking into account six factors: (1) workplace strategy; (2) financial analysis; (3) customer reach and effective service delivery; (4) access to talent; (5) highest and best use of facilities; and (6) communications network analysis. Id. at 17–18. Cushman Wakefield summarized the current state and desired future state for the facilities. Like Mortenson’s report, the Cushman Wakefield study contained “scorecards,” which also summarized recommendations for each property. See id. at 45–46; see also NS-PGL Ex. 19.0 at 19–23. Notably, each of the scorecards recommended the actions that Peoples Gas either has taken or is now taking with respect to these facilities. Id. at 23. The record also contains NS-PGL Ex. 19.03, a collection of photographs from the facilities that show the deteriorating conditions of the buildings. These photos further demonstrate the urgent need Peoples Gas faced to replace these facilities for the health and safety of its employees and to continue to be able to provide timely, reliable, and safe service to customers. NS-PGL Ex. 19.0 at 23. The AG and PIO witnesses’ dismissal of these reports in their rebuttal testimony ignores
the overall findings of the studies, which was that the facilities were old, inefficient, unevenly utilized, expensive, and dangerous. AG Ex. 7.0 at 19–22; PIO Ex. 7.0 at 5–11.

In response to these findings, Peoples Gas took necessary and reasonable steps to modernize its facilities, which are summarized in an illustrative chart in Ms. Eldringhoff’s direct testimony. PGL Ex. 3.0 REV CORR at 14. The Division Street Shop was not replaced; rather its functions were moved to the Logistics Support facility and the CBD Sub-Shop.

The new facilities provide significant operational benefits, which can be grouped into three categories: (1) improving facility efficiency; (2) improving operational function; and (3) improving safety. PGL Ex. 3.0 REV CORR at 16.

Peoples Gas carefully vetted these facilities improvements before proceeding with their construction. In addition to the studies described above, the record includes the Senior Project Team presentations that were used to gain internal management approval for constructing the facilities. PGL Ex. 3.3, Sch. 1–4; NS-PGL Ex. 25.02. Despite arguments to the contrary (AG Ex. 7.0 at 18; PIO Ex. 7.0 at 5), these are the types of documents routinely used to support such projects in rate cases, and their use is not contested for other major capital projects in this case.

Peoples Gas also employed appropriate cost controls when building the facilities. It conducted a competitive bidding process to select the design/build contractor. It also hired a Facility Program Manager with 30+ years of experience in development and facility construction to represent PGL and oversee project execution. One of the Program Manager’s responsibilities was to engage the general contractor and architect of record in value engineering efforts to minimize building costs. These efforts began at concept design and continued all the way through construction. Once a budget was proposed, there was a strict corporate governance process to request approval for a final budget. Peoples Gas reviewed and approved all sub-contractor bid awards during the design and construction phases. Peoples Gas also leveraged its corporate contracts to obtain preferred pricing for owner-supplied items such as furniture, Information Technology equipment, and AV equipment. Along with the Program Manager, Peoples Gas employed an internal team of project managers and a cost analyst to provide proper scrutiny of all change orders from the general contractor prior to review and approval by the Director of Facilities. Projects followed the cost approval governance process described earlier, including upfront review and approvals of budgets and monthly financial updates to senior management to ensure the project was tracking to budget, with the goal always being to spend under budget. PGL Ex. 3.0 REV CORR at 17–18.

AG witness Walker does not directly contest the cost of constructing the facilities. The closest he comes is to compare the final project costs to Mortenson’s preliminary estimates. AG Ex. 7.0 at 24–26. According to Peoples Gas, that collateral attack is unpersuasive, and the Commission should reject it for several reasons.

First, the Mortenson estimates were never intended to be full-cost forecasts to replace the facilities. To the contrary, Mortenson provided preliminary estimates to aid Peoples Gas in decision-making before management made any decision to proceed with construction. To begin, Mortenson assumed that an identical, generic, and rather small 55,000 square foot facility would be built to replace each of the shops. NS-PGL Ex. 19.02
Mortenson’s (and Mr. Walker’s) planning assumptions about the cost to replace the facilities are based on this generic 55,000 square foot shop. In reality, the new North and Central Shops are 83,500 and 76,000 square feet, respectively, and the South Shop will be 85,000 square feet. NS-PGL Ex. 30.0 at 9–10.

Second, the Mortenson preliminary estimates reflect only hard costs, which are mainly building and site improvement costs, and exclude property costs, owner’s costs, and soft costs (design, project management, furniture, shop equipment/tools, and IT/AV equipment costs). That is, Mortenson’s estimates accounted for only a portion of the overall cost of the new facilities; a detailed cost estimate for the facilities simply was not within Mortenson’s scope of work. The detailed cost estimates for the facilities are contained in the slide decks presented to management for approval, PGL Ex. 3.3 and NS-PGL Ex. 25.02. Id. at 10.

Third, Mortenson’s report was completed in 2015; the construction at issue here began three to four years later, between 2018 and 2019, and continued through 2020 (the South Shop will continue through 2025). Mr. Walker incorrectly attempts to account for inflation over this period by escalating Mortenson’s 2015 estimates at 2.5% per year, which he calls a “generous allowance.” AG Ex. 7.0 at 25 and n.42. In fact, construction inflation rose at 3.65% annually in Chicago over the 2015-2020 period that Mr. Walker examined, and with the significant spike in construction costs since 2020, the compound annual growth rate for construction costs in the city from 2015 through 2022 was 6.26%. Over those eight years, Mr. Walker’s supposedly “generous” assumption deviates significantly from actual inflation trends. NS-PGL Ex. 30.0 at 10–11.

Beyond this invalid comparison to the Mortenson report, it is important to consider that Peoples Gas competitively bid the South Shop work and chose the lowest bidder for that work. This competitive bidding process provides the Commission with perhaps the best indication that the price for the South Shop is reasonable — it is being built for the lowest price available in the market. For the other facilities, Peoples Gas issued a request for proposals to multiple firms for a Master Developer to execute the facilities plan that had been developed by Cushman & Wakefield. A joint venture between McKissack & McKissack and FH Paschen was selected as the lowest cost responsive bid and awarded the Master Development Contract. One of the first actions required of FH Paschen was to validate Cushman & Wakefield’s proposed Master Plan. FH Paschen used benchmarked North Shop costs to extrapolate the projected program cost across proposed sites. Peoples Gas also retained a third-party cost estimator to prepare a secondary opinion of probable North Shop costs for program development. NS-PGL Ex. 30.0 at 8–9.

Recognizing the need to confirm market costs to understand the actual cost of the proposed projects, the Master Development Contract required FH Paschen to competitively bid all the work required to complete the projects. The bid comparisons were then submitted to Peoples Gas with a recommendation of award so that all work could be completed for the least cost dictated by market conditions in the area at the time of construction. Id. at 9. The Companies assert that there is no basis to conclude this construction was more costly than it should have been.
Mr. Walker argued that Peoples Gas "has failed to justify that these top tier facilities were necessary in this form, now, and at this cost." AG Ex. 3.0 at 48. This implies that even if the facilities needed to be replaced, Peoples Gas may have made them larger or more luxurious than necessary. Mr. Walker has not provided any evidence to support his opinion. These facilities were built to meet modern standards (including building codes and Americans with Disabilities Act ("ADA") standards) for construction, technology, and employee safety and comfort. They are not “gold plated” and their sizes were chosen to meet Peoples Gas’ operational needs. The record demonstrates that the decisions to construct the new facilities at issue for the health, safety, and efficient operations of Peoples Gas’ frontline workers and to ensure continued safe and reliable service to its customers, in light of the alternatives presented, were reasonable at the time they were made. NS-PGL Ex. 19.0 at 24–25.

The Companies further state that PIO witness Elder’s critique alleging inadequate benchmarking (PIO Ex. 7.0 at 11–12) should be rejected. She criticized Peoples Gas for benchmarking only the construction cost of the North Shop and not the other facilities. However, North Shop was the first shop that Peoples Gas constructed under its program. Peoples Gas commissioned a detailed cost estimate for the shop, as Ms. Elder conceded in her rebuttal testimony. However, Peoples Gas did not go through a similar exercise for the other shops because they were also being built in relatively close timing and proximity (i.e., within Chicago City limits) and were of similar design. NS-PGL Ex. 30.0 at 11. As a result, it was reasonable and prudent to use the North Shop costs as a benchmark for subsequent construction.

Setting aside these critiques, no party has offered evidence that the facilities should not have been constructed or could have been constructed for less. That leaves the AG and PIO with just two related arguments against recovery of these costs: (1) Peoples Gas did not adequately consider the option of repairing or refurbishing existing facilities versus replacing them; and (2) the revenue requirement of refurbishing the shops might have been less than the revenue requirement of replacing them. AG Ex. 3.0 at 46–49; AG Ex. 7.0 at 17, 22–26; PIO Ex. 7.0 12–14. Both arguments fail.

The first argument about whether Peoples Gas appropriately considered alternatives is disproven by the record. The AG and PIO ignore the fact that Peoples Gas did consider refurbishment and chose that option where possible. It simply is not true that Peoples Gas blindly decided to replace every facility addressed in Mortenson’s report. To the contrary, PGL repaired or refurbished a number of facilities, following Mortenson’s recommendations. NS-PGL Ex. 19.0 at 7 (listing numerous facilities repaired via O&M budgets between rate cases, at shareholder expense); NS-PGL Ex. 30.0 at 5–6 (North, Central, and South Shops were in the minority of facilities recommended for replacement).

The AG and PIO also ignore the reality that it simply was not feasible to repair or refurbish the older facilities Peoples Gas ultimately decided to replace to improve safety and better serve customers. Their testimony appears to wish away the practical challenges of attempting to renovate the existing facilities. Telling in this regard are the results of Cushman & Wakefield’s interviews with employees about the existing facilities. NS-PGL Ex. 19.01 at 31, 33, 36; see also NS-PGL Ex. 30 at 7.
The employee concerns and similar concerns come up repeatedly in the Cushman & Wakefield study. While it may be easy now for Ms. Elder to dismiss these as mere “qualitative” issues, for Peoples Gas and its employees, they were daily real-world, critical concerns that had to be addressed. *Id.* at 6–8; *see also* PGL Ex. 3.0 REV CORR at 15 (further explaining why “the considerable age of the facilities, ranging from 55-115 years, resulted in diminishing returns for most building systems and envelope upgrades,” and that “complete building renovation was not recommended due to the likelihood of asbestos and other costly environmental materials in the existing facilities”).

Despite the insufficient evidence presented by their witnesses, the AG and PIO insist that Peoples Gas should have considered other options or reached different conclusions. This ignores well-established standards for prudence in rate cases. “Prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made.” *Ill. Power Co. v. Ill. Commerce Comm’n*, 339 Ill. App. 3d 425, 428 (5th Dist. 2003). The Commission can only disallow costs if the record evidence establishes imprudence or unreasonableness in the utility’s business and management decisions. *See, e.g., Bus. & Prof’l People for Pub. Interest*, 279 Ill. App. 3d 824, 829–30 (1st Dist. 1996); *City of Chi.*, 133 Ill. App. 3d, at 442-43. “Hindsight review is impermissible” in the analysis of prudence. *Ill. Power Co.*, 339 Ill. App. 3d at 428. Once a utility presents sufficient evidence of the prudence and reasonableness of its test year costs of service, the burden shifts to the parties proposing adjustments to support their positions with evidence that the forecasted costs are imprudent or unreasonable. *City of Chi.*, 133 Ill. App. 3d at 442–43; *see also* *Ill. Commerce Comm’n on Its Own Mtn. v. Ill. Consol. Tel. Co.*, Docket No. 94-0042, 1995 Ill. PUC LEXIS 828, at *103 (Dec. 6, 1995).

The AG and PIO are engaging in pure hindsight review, attempting to nitpick the analysis that Peoples Gas and its multiple experts performed by saying that they did not consider this or that alternative set of facts. The legal question is whether PGL’s actions were reasonable under the circumstances that existed at the time. The short answer is yes: PGL’s actions were reasonable and prudent. Here, where Peoples Gas retained multiple industry-leading subject matter experts who recommended replacement, and knew from its own hands-on experience that replacement was necessary, its actions more than meet that standard.

As to the second argument regarding the relative costs of alternatives, it stands to reason that the revenue requirement for replacing the facilities is greater than the cost of keeping them together with continued repairs, as the AG and PIO would apparently have had PGL do. These facilities were fully, or almost fully, depreciated and so had minimal capital costs. That the new facilities Peoples Gas seeks to add to rate base are more expensive, on a revenue requirement basis, should not come as a surprise. However, as explained above, that cost is justified given the state of the legacy facilities and the near-impossible task of renovating them to the necessary standard, and notably, Staff proposes no such disallowance. NS-PGL Ex. 30.0 at 8.

The AG and PIO provide no legal authority for their position that the most important (and seemingly only) relevant consideration is the relative revenue requirements for refurbishment versus replacement — because there is none. Certainly, cost is important,
but it is far from the only criterion, and the AG and PIO never fully articulate why the other factors PGL considered — customer service, operating efficiency, employee safety, ADA compliance, reducing environmental impacts, and so on — should be disregarded. There is no basis to disallow the inclusion of these investments in rate base. There is no justification for Mr. Walker’s initial proposal to delay the decision on recoverability pending the introduction of additional evidence supporting the reasonableness of these decisions in some future proceeding or his subsequent proposal to disallow them entirely. The Commission should approve inclusion of these costs in rate base in their entirety.

Lastly, the AG’s emphasis on the utility’s “burden” is misplaced. Peoples Gas does not dispute that it bears the burden of demonstrating that investment in plant is prudent and reasonable; however, once it has made that case, as it has here, the AG and others cannot justify a disallowance merely by criticizing the decision alone without demonstrating significantly more. The AG never says whether it thinks Peoples Gas failed to make even a prima facie case of reasonableness, or whether — despite that showing — the Commission can order a disallowance without any further showing by the AG. The Companies dispute this and claims that the AG’s position is inconsistent with Illinois law.

Instead, they complain that Peoples Gas should have completed even more studies, or developed even more precise cost estimates, or considered facilities of different (but unidentified) size and scope, or thought even harder about how to save money, presumably all at the cost of delaying action and exacerbating risks to employee health and safety. That is pure, impermissible hindsight review. Ill. Power Co., 339 Ill. App. 3d at 428. The Commission should reject both the “full” and “alternative” adjustments proposed by the AG, as supported by other intervenors, and approve recovery of the People Gas’ facilities costs in full.

(ii) AG’s Position

The AG argues that the record does not support PGL’s position that the newly constructed state-of-the-art top-tier facilities were necessary, or that significantly less costly alternatives were unavailable. The AG asks the Commission to disallow PGL’s request to recover approximately $236.2 million for five facilities and the renovation of one existing facility because it failed to demonstrate that: (1) the old facilities were unable to support the provision of service to PGL’s customers; (2) the new facilities are appropriate in size and scope; (3) sufficient alternatives analyses were performed on options other than “do nothing” and “repairs”; and (4) the magnitude of the investments represent a reasonable use of ratepayer funds. AG Ex. 3.00 at 45, 48–49; AG Ex. 7.00 at 23–24. The AG asserts that the facilities reports PGL cited to in its rebuttal testimony provide only conclusory statements, no meaningful analyses, and actually show that PGL’s negligent maintenance practices likely contributed to the facilities’ dilapidated condition. The AG contends that PGL failed to provide information sufficient to satisfy its statutory burden, and that therefore, the Commission should disallow PGL’s request for $236.2 million.

In support of its $236.2 million request, PGL claims that it considered two alternative approaches to constructing these new facilities, either (1) do nothing or (2) perform upgrades/improvements. The AG notes that PGL did not consider these options
for its support facility, which it renovated instead of rebuilding. AG Ex. 3.00 at 46, citing PGL Sch. F-4. PGL claims that based on its alternatives analysis, it concluded that four of the five facilities had to be newly built to “improve operations and achieve long term benefits,” and that the existing condition of the previous operational facilities was aging and not efficient. See PGL Ex. 3.1, col. (E).

The AG argues that PGL’s alternatives analysis is fatally deficient. According to PGL, it would not be able to serve its customers at a “modern utility level pace” if it did nothing. PGL Ex. 3.1, col. (F). However, the AG contends that PGL provided no analysis or examples demonstrating that its existing facilities rendered it unable to serve its customers at a “modern utility level pace,” or what exactly a “modern utility level pace” even means. The AG asserts that PGL’s so-called analysis is incomplete and subjective, and that it does not constitute evidence upon which the Commission can base any finding of reasonableness or prudence.

As for PGL’s consideration of the option for upgrades and improvements, it asserts only that upgrades would be “very costly,” and that this would require compliance with “Chicago building code ordinances.” Id. The AG argues that PGL again provides no cost estimates for repairs or upgrades, and no analysis that shows how or why such repairs would be very costly. The AG highlights that PGL’s citation to its Mortenson report in support of its decisions actually establishes the exact opposite — that its decisions are unjustified. Although the Mortenson report still lacks any comparative analysis, the AG argues that it shows the estimated cost to repair — for example, the North Shop facility was $3,949,000 while the estimated cost to build a new such facility was $24,700,000–$28,400,000. PGL Ex. 19.02 at 254. According to the AG, this report discredits PGL’s claim that upgrades and improvements would be very costly. The Mortenson report notwithstanding, the AG asserts that PGL’s alternatives analysis provides no basic information and no cost-benefit analysis—which are necessary to evaluate PGL’s decision. Without this information, the AG contends there is no way for the Commission to determine whether PGL’s proposed costs for these facilities are reasonable.

The AG further argues that PGL’s facilities reports offer only conclusory statements, no meaningful analysis, and show that its negligent maintenance practices contributed to the facilities’ dilapidated state. AG witness Walker testified that the Commission should defer recovery of the cost of these new facilities due to the lack of supporting analysis and justification. AG Ex. 3.0 at 49. In response, PGL provided three additional reports in support of its facilities decisions: (1) the Cushman Wakefield report, (2) the McKissack Paschen report, and (3) the Mortenson report. AG Ex. 7.00 at 17.

According to the AG, while the Cushman Wakefield report claims to contain renovation scenarios, it does not. Id. at 17. The AG points out that this report simply contains conclusory assertions. See, e.g., PGL Ex. 19.01 at 100; see also AG Ex. 7.00 at 19. The AG argues that the report does not contain any cost-benefit analysis of alternatives, nor evidence that would support dismissal of the repair option or that the costs to purchase and renovate an existing building were even considered. Id. Critically, the AG argues that the Cushman Wakefield report agrees with the AG that new facilities would result in higher total costs over a 20-year timeframe — even when higher O&M costs for the existing facilities are accounted for. Id. at 20.
The AG points out that this remains true when the figures from the Cushman Wakefield report are escalated into present dollars, and that this report similarly lacks meaningful assessment of alternatives or analysis of any operating or ratepayer benefits. The AG also notes that PGL’s proposal for $236.2 million is far more than what the Cushman Wakefield report describes, which the AG contends renders the report outdated and obsolete. PIO witness Elder, an economist, drew similar conclusions regarding the Cushman Wakefield report. See PIO Ex. 7.00 PUB at 7–10.

According to the AG, the McKissack Paschen report falls well short, too; it only “confirm[s] and/or update[s] the development strategy, scope, schedule, and budget for each discreet facility project identified in the CW [Cushman Wakefield] Master Plan – Facility Footprint Strategy/Facility Footprint Recommendation Section.” PGL Ex. 19.01 at 312. The AG argues that it also does not evaluate alternatives, cost reasonableness, operational necessity, or provide any further meaningful perspective. AG Ex. 7.00 at 20. Mr. Walker testified that the only additional information he discovered in the report was a note mentioning that PGL would likely have to perform environmental abatement prior to the divestiture of the old facilities. Id. Since abatement was one of the few things identified as being cost-prohibitive for the renovation scenario, Mr. Walker added that he found it “even more confusing” why that alternative was discarded when abatement had to occur anyway. Id.

According to Mr. Walker, the Mortenson report primarily focuses on assessing existing facility conditions. Id. Notably, Mr. Walker indicated that the report states, “…a lack of ongoing capital investment in maintenance programs has resulted in compounding issues. A prime example would be unchecked roof leaks that results in drywall, paint, and ceiling damage.” Id., citing PGL Ex. 19.02. The record establishes the extent of this problem; PGL’s report shows how its deficient maintenance practices have contributed to deteriorating, dilapidated infrastructure of the facilities at issue. See, e.g., PGL Ex. 19.03 at 6-9, 18, 20-23. Despite this evidence of negligent property management, the AG argues that PGL now seeks to wrongly shift those costs onto its ratepayers. The AG urges the Commission to reject PGL’s unsubstantiated request.

In addition, while the Mortenson report proposes to replace several of the Companies’ facilities, it also shows that issues related to the then-existing facilities could have been addressed at a far lower cost — as low as in the tens of millions instead of hundreds of millions. AG Ex. 7.00 at 21. For example, the AG states that PGL seeks to add $69,300,000 to rate base for the North Shop, but that the report shows the estimated cost to upgrade and repair that facility was only $3,949,000, compared with the estimated cost of $24,700,000–$28,400,000. PGL Ex. 19.02 at 254. The AG argues that by any measure, there is no question that the cost to upgrade and repair would have been a fraction of the cost of new construction. The Mortenson report is not alone in this observation, however; the AG notes that the other reports — as shown — similarly concluded that the cost for new construction would vastly exceed the cost of upgrading or improving existing facilities. The AG argues that PGL ignored or never properly considered these potential savings in its approach.

PGL further argues that it established its prima facie case for recovery of these costs. Generally, it maintains “that it simply was not feasible to repair or refurbish the older facilities [and that] Peoples Gas ultimately decided to replace to improve safety and
better service customers.” NS/PGL IB at 54. In support, PGL merely cites a handful of unquantified employee complaints: “no air conditioning,” “ADA compliance,” “long walk to the parking lot,” no place “to sit outside and get fresh air,” “no green space,” rats, and bugs. Id. at 55. Essentially, PGL contends that the AG did not explain why these complaints should be disregarded. Id. at 57. The AG contends that this accusation is disingenuous and without merit.

First, the AG argues it never disregarded the complaints raised by PGL, and that PGL’s false accusation deflects from the central question, which is not whether the AG disregarded these concerns, but whether the record justifies PGL’s decision to spend $236.2 million. The AG contends it does not. As shown, the AG points again to PGL’s own reports that show that the complaints listed above, and the required repairs identified by the Mortenson report, could have been addressed at a significantly lower cost to ratepayers. See, e.g., PGL Ex. 19.02 at 254–255. The record clearly does not support PGL’s conclusion that these new facilities were “necessary” because “renovating them to a necessary standard would [have been a] near-impossible task.” NS/PGL IB at 57.

Second, the AG notes once more that the record shows that the dilapidated state of PGL’s existing facilities was a result of its negligent maintenance. Again, PGL’s own Mortenson report provides ample examples affirming the AG’s position; it concluded that “… a lack of ongoing capital investment in maintenance programs has resulted in compounding issues. A prime example would be unchecked roof leaks that result in drywall, paint, and ceiling damage.” AG IB at 27, citing PGL Ex. 19.02 at 3; see also PGL Ex. 19.03 at 6–9, 18, 20–23. It is neither least-cost, prudent, reasonable, nor equitable for PGL’s ratepayers to pay the full cost for PGL’s poorly maintained properties. See 220 ILCS 5/1–102, 5/9–101.

Finally, the AG argues that the Commission should reject PGL’s request because it has declined to provide requisite information that would allow the Commission (and stakeholders) to sufficiently evaluate the costs and benefits of PGL’s decision to build these new facilities instead of using alternative approaches. The AG states that PGL’s decision to withhold such information is particularly troubling given it readily admits that “the revenue requirement for replacing these facilities is greater than the cost of keeping them together with continued repairs…” and that “the new facilities Peoples Gas seeks to add to rate base are more expensive … [and] should not come as a surprise. NS/PGL IB at 56–57. PGL further stated that the replaced facilities “were fully, or almost fully, depreciated and so had minimal capital cost.” Id. at 57. In other words, AG argues that because PGL is also no longer able to recover a return on their capitalized costs, this may be viewed as an effort to boost its rate base and reset its revenue stream, which is particularly concerning given the extraordinary increase to rate base consumers are currently facing due to PGL’s replacement of its aged cast iron mains. The AG notes that PGL charges consumers on a cost-plus basis for capital additions, and that generally, cost-plus recovery does not incentivize entities to make efficient or least cost choices. The AG refers the Commission to the “Averch-Johnson” effect, a seminal economic analysis that demonstrated that utilities subject to cost-plus, rate-of-return regulation have a perverse incentive to increase capital spending, “gold plate” their assets, and thereby increase the aggregate return for shareholders. See Fed. Comm’n Comm’n, I/M/O Policy and Rules Concerning Rates for Dominant Carriers, Docket No. 87-313, FCC 89-
91, 4 FCC Rcd 2873 at §77 (Apr. 17, 1989). Accordingly, the AG argues that the record does not support PGL’s decision to build new facilities as an efficient and/or reasonable one.

The AG asserts that PGL was afforded multiple opportunities in this proceeding to provide its alternatives analysis and cost-benefit analysis to demonstrate that its decision to build new construction or remodel each facility was the most cost-effective approach. At every such opportunity, the AG points out that PGL declined to do so. The AG asserts that PGL’s support is comprised of outdated and conclusory reports that offer no meaningful analysis. Further, the AG avers that these reports in fact support their position that PGL’s decisions were unjustified, and that its deficient maintenance practices are at fault. For these reasons, the AG asks the Commission to disallow $236.2 million for these facilities.

In the alternative, should the Commission conclude an amount less than the entire cost should be disallowed (it should not), the AG alternatively asks the Commission to reduce PGL’s request by $66.35 million. This amount represents the recovery of the costs that are in excess of the average cost estimate provided in the Mortenson report on a per-square foot basis because as PGL claimed it used this in determining the cost to replace the facilities at issue. AG Ex. 7.00 at 24. The AG notes that this alternative disallowance does not fully account for PGL’s failure to properly care for its facilities or to consider less costly alternatives.

Mr. Walker compared the costs PGL requests to recover with the costs contained in the Mortenson report, including the total square feet of each project and year the project was or will be completed. Id. at 25. Mr. Walker calculated the difference between the average costs provided in the Mortenson report, escalated with inflation to the construction completion year, and the costs PGL provided for its facilities. Id. Mr. Walker multiplied the difference between the cost per square foot in the Mortenson report and that in PGL’s testimony for each facility to calculate the alternative disallowance of $66.35 million.

Although the AG offers this alternative disallowance, it reasserts that PGL’s lack of alternatives analysis, unjustified demolition and reconstruction of new facilities, and their deficient maintenance practices support the AG’s recommendation that the Commission disallow $236.2 million for these facilities.

(iii) City’s Position

The City supports the AG’s positions with respect to shops and related facilities.

(iv) PIOs’ Position

PIO maintain that the Commission should consider PGL’s spending on new buildings in the context of the PGL’s bills — which are already unaffordable for a large swath of PGL’s customers — and the trend towards electrification, which will drive down sales and make bills even more unaffordable for PGL’s remaining customers in the future. PIO maintain that Peoples Gas has not demonstrated that it acted with caution when considering upgrades to its operational facilities because it failed to rigorously examine alternatives to new construction. In its Initial Brief, Peoples Gas makes two main arguments in support of its decision to invest in new operational facilities. First, Peoples
Gas argues that its legacy facilities were outdated and in poor condition. Second, Peoples Gas leans on certain reports PGL commissioned (the Mortenson study, the Cushman Wakefield report, and the McKissack & McKissack and FH Paschen report), which assessed the state of PGL’s legacy facilities, and, according to PGL, “confirmed the need to replace several of PGL’s facilities.” *Id.* at 34-47.

PIO assert that the PGL’s arguments miss the point. PIO state that no party fundamentally disputes the legacy facilities in question — the North, Central, and South shops — were old and outdated. No party argues that operating the legacy facilities without any improvements would have been in the best interests of PGL’s customers or its employees. Indeed, PIO have argued that like any gas utility, PGL must make investments to address safety risks. PIO assert, however, that the law requires that Peoples Gas act prudently. Prudence does not demand PGL address safety issues “at all costs”, but rather, requires Peoples Gas to exercise “the standard of care that a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time a decision was made.” *Ill. Power Co. v. Ill. Commerce Comm’n*, 245 Ill. App. 3d 367, 371 (3d Dist. 1993). The Illinois Appellate Court has established that costs that are unnecessary to the provision of service, or that a utility has failed to justify, are not prudent. *Ill. Power Co.*, 245 Ill. App. 3d 367, 371-72. Moreover, the utility retains the burden of persuading the Commission that its investments were prudent throughout this proceeding. *Ambrose v. Thornton Twp. School Trustees*, 274 Ill. App. 3d 676, 690 (1st Dist. 1995), app. den., 164 Ill. 2d 557 (1995); *Chi. Bd. of Trade v. Down Jones & Co*, 108 Ill. App. 3d 681, 686 (1st Dist. 1982). Thus, PIO maintain that for the Commission to conclude that Peoples Gas’ shop investments were prudently incurred, it is not enough for PGL to show its legacy facilities were old, outdated, or in poor condition. Nor is it sufficient for Peoples Gas to point to conclusory recommendations in reports PGL itself commissioned. In PIOs’ estimation, PGL must provide record evidence demonstrating that the costs of constructing new operational facilities are justified and necessary to provide service to its customers.

PIO assert that Peoples Gas fails to meet this burden. They note that in response to a PIO discovery request, Peoples Gas admitted the Cushman Wakefield report did not compare the net costs associated with construction of new operational facilities with the net costs associated with refurbishment, repair, remodeling, or refinishing of the legacy shops. PIO Ex. 7.2 at 4. Peoples Gas has not explained how it made tradeoffs between various projects, or whether it considered its customers’ ability to absorb the costs of new operational facilities and the associated increase in rates, particularly in light of PGL’s high rates and significant proposed investments in pipeline infrastructure. PIO Ex. 7.0 at 12. PIO further note that PGL admitted in response to a PIO discovery request that it did not benchmark the cost of any of its new operational facilities, apart from the new North Shop facility. PIO Ex. 7.2 at 2 (Peoples Gas Response to PIO 8.07b). Nor did Peoples Gas project the per-customer cost of its new operational facilities and factor that projection into its decision-making regarding whether to proceed with constructing new facilities. PIO Ex. 7.2 at 2 (Peoples Gas response to PIO 8.07c). PIO maintain that Peoples Gas leans heavily on qualitative evidence, quotes, and assessments showing that its legacy shops were in poor condition. PIO state Peoples Gas does not, however, present any data or analysis showing that repairing, refurbishing, or renovating the existing facilities to enhance the facilities’ safety and efficiency would not have allowed
Peoples Gas to provide adequate utility service, or that the costs of repair would have exceeded the cost of building new facilities. Critically, Peoples Gas failed to provide any analysis comparing the cost of repairing the facilities with the costs of replacement (or, alternatively, the net benefits to ratepayers of each option). Hence, PIO maintain that Peoples Gas has not demonstrated its investments were in ratepayers’ best interests.

Peoples Gas argues that repairing or refurbishing its legacy facilities was “simply not feasible[].” NS-PGL IB at 54. However, PIO explain that Peoples Gas does not support that claim with any quantitative feasibility analysis. Instead, PGL points to a series of employee complaints summarized in the Cushman Wakefield report. See id. at 54-55. Again, those complaints generally and anecdotally illustrate poor conditions in the legacy facilities, but do not constitute analysis establishing that refurbishing or repairing each legacy facility would have been “infeasible.”

Peoples Gas also asserts that its new facilities “reduce the overhead expense associated with the older facilities by reducing the cost of maintenance, repairs, and utilities by about $700,000 per year.” NS-PGL IB at 48. PIO assert that this fact, if true, suggests only that constructing new facilities may have been better for ratepayers than simply maintaining the outdated legacy facilities “as-is.” That fact does not, however, provide the Commission any information about whether constructing new facilities was better for ratepayers than alternative options, including renovating, repairing, or refurbishing the legacy facilities. In other words, Peoples Gas fails to put the O&M savings associated with its new facilities in proper context.

Peoples Gas also references several buildings it chose to refurbish, and argues those decisions demonstrate Peoples Gas considered alternatives to replacement. PIO state that PGL’s argument is a red herring. The fact that PGL may have pursued refurbishment over replacement for certain of its buildings is not relevant to the Commission’s determination of whether PGL’s investments in the facilities at issue in this proceeding were prudent. PIO maintain that to the extent Peoples Gas rigorously analyzed alternatives and acted prudently with respect to certain other investments, this fact does not demonstrate Peoples Gas rigorously analyzed alternatives and acted prudently with respect to the operational facilities at issue in this proceeding.

PIO explain that AG witness Walker describes in detail several other flaws in PGL’s analysis. He notes that Peoples Gas did not provide any substantive analysis demonstrating that the two alternatives to renovating or constructing new facilities – (1) Do Nothing and (2) Perform Upgrades/Improvements—were insufficient to provide utility service or were more costly than renovation/new construction. AG Ex. 3.0 at 46-47.

Therefore, while PGL’s legacy facilities may have been in poor condition, PIO maintain that the record nevertheless does not demonstrate PGL’s decision to construct new facilities was prudent. Contrary to PGL’s arguments, this conclusion does not require hindsight review. PIO state that PGL’s decisions to invest in new operational facilities are imprudent because Peoples Gas did not conduct the analysis it should have conducted to ensure its investments were in its customers’ best interests, not because new information renders those decisions imprudent in hindsight.

PIO maintain that had Peoples Gas compared the costs of refurbishment to the costs of replacement, it likely would have chosen to improve conditions at its legacy
facilities without constructing new facilities. PIO witness Elder compares the amortized costs of PGL’s new operational facilities (approximately $20 million per year) versus PGL’s historic O&M spending on its legacy facilities (approximately $2.2 million per year) and concludes Peoples Gas could have significantly increased the amount of money it spent on upgrades without approaching the costs its new facilities entail. PIO Ex. at 7.0 at 12-13.

PIO assert that this issue — much like many of the issues PIO have raised in this proceeding — boils down to the impacts that PGL’s investment decisions have on its customers. They maintain that the record demonstrates Peoples Gas did not adequately consider impacts on its customers when it decided to invest in new operational facilities. That fact would be problematic under any circumstances but is particularly concerning in light of the affordability pressures Peoples Gas customers already face (even before factoring in the rate increase likely to result from this case). It is also concerning in light of accelerating electrification, which will require Peoples Gas to recover its costs over fewer sales and customers in the future. PIO thus request that the Commission disallow $239,006,000 of Peoples Gas’ proposed rate base additions associated with upgrading its legacy operational facilities.

(v) Commission Analysis and Conclusion

The AG and PIO argue, generally, PGL failed to provide sufficient evidence demonstrating: (1) the old facilities (if renovated) were unable to support the provision of service to PGL’s customers; (2) the new facilities are appropriate in size and scope; (3) appropriate alternatives analyses were performed on options other than “do nothing” and “repairs”; and (4) the magnitude of the investments represent a prudent use of ratepayer funds. Both the AG and PIO take issue with the reports cited by the Company in support of its new facilities, arguing the reports (1) offer only conclusory statements; (2) contain no meaningful analysis; and (3) demonstrate that PGL’s negligent maintenance practices contributed to the facilities’ dilapidated states.

The Commission notes that PGL presented evidence the buildings were in poor condition. See NS-PGL Ex. 19.02. The newest shop, the North Shop, was constructed in 1937 and the oldest, the South Shop, dates to 1906. PGL also demonstrated the layout of some of the facilities had not kept up with modern needs, resulting in inefficiencies and potentially dangerous conditions for employees. No party argues that operating the legacy facilities without any improvements would have been in the best interests of PGL’s customers or its employees. However, the Commission agrees with the AG and PIO that the record does not contain sufficient evidence demonstrating that the newly constructed facilities were prudent.

The record does not support a finding by the Commission that PGL met its burden to support its request to recover these costs through rate base. The Company included three reports in the record from Mortenson Construction, Cushman and Wakefield, and McKissack/FH Paschen that identify issues with existing buildings and provide recommendations on how to address them. The reports provide solutions and strategies to ameliorate the problems with existing buildings. However, as noted by AG witness Walker, the Company fails to demonstrate that the costs it incurred here were prudent, after considering alternatives. See AG 7.00 at 23. The Commission agrees with AG
witness Walker that the Company has failed “to supply cost-benefit analyses for each facility and a thorough alternatives analysis for each facility that evaluated the cost and operational considerations of repair, repurpose, and replace options.” AG 7.00 at 22.

The Mortenson report identifies repairs and upgrades for each shop that could have been pursued to maintain their operations. For example, it shows that issues related to the then-existing facilities could have been addressed through repairs at a much lower cost than wholesale replacement. See PGL Ex. 19.02 at 255–262. PGL seeks to add $69,300,000 to rate base for the North Shop, but the Mortenson report shows the estimated cost to upgrade and repair that facility was only $3,949,000. See id. at 254. The record is unclear as to whether PGL considered this or other alternatives when developing a strategy to modernize its facilities, giving the Commission no insight into how PGL concluded all five shops and facilities identified by the AG and PIO needed to be replaced immediately.

The Commission finds the Company fails to show why it could not have pursued the investments identified in the facilities improvement list in the Mortenson report to continue operating existing shops, delay the need to build new shops, or pursue some combination of the two. See id., at 256-262. The Commission acknowledges that a least-cost standard is not applicable on these facilities. However, the Company must consider the cost to ratepayers when it embarks on capital investment, especially when the Company’s own report identifies cheaper alternatives. The Commission is concerned that, in light of the response to PIO DR No. 8.07, the Company provides no clear indication that it balanced the need for new shops with its other capital investments. Specifically, the data request asks, “How did the Company balance the need for its new shops with its other capital investments?” PIO Ex. 7.2. Instead of directly answering the question, PGL responded only with its process for internal project approval and provided no explanation of its consideration of the costs of these projects in the context of the Company’s total portfolio.

The Commission finds that analyses of alternatives to new, upgraded replacement facilities, cost-benefit projections for the investments, and rate impact assessments – with supporting documentation – are reasonable steps that a utility should take before initiating a capital investment project of this magnitude. In addition, the Company does not address the apparent lack of planning that led to a decision to rebuild all the facilities at nearly the same time. Based on the reasons above, the Commission adopts the AG’s recommendation to disallow $236.2 million for these facilities including the consideration of future rate base costs related to the South Shop. CWIP costs related to the South Shop are discussed in Section IV.B.2.e below.

e. Program Management

(i) Companies’ Position

The Companies state that the stipulated outline lists “Program Management”—apparently a reference to Peoples Gas’ management of the SMP—as a contested capital addition. Because no party proposes any specific capital disallowance relating to this issue, there is in fact no capital addition in dispute. To the extent various parties criticize SMP’s management and progress to date, the Companies address those issues in this Section.
The Companies explain that over the past decade, the Peoples Gas SMP has been the subject of repeated, comprehensive reviews by the Commission, Staff, and independent engineering firms approved by the Commission to ensure that the program is appropriately planned and implemented. The SMP has also been reviewed by various other parties, such as the AG, in multiple other regulatory proceedings, including proceedings that are currently pending. Peoples Gas continues to provide extensive reporting to the Commission on the SMP. Moreover, the Commission conducts an independent proceeding to review and evaluate each year of SMP expenditures, as required by statute. In sum, it is fair to say that the SMP has been and continues to be the subject of extensive Commission scrutiny through established regulatory processes and is easily one of the most studied construction projects by any Illinois utility.

Notwithstanding these robust existing regulatory review mechanisms, the AG seeks to use this rate case to revisit SMP project management issues. As Companies witness Eidukas described it, the AG “advocate[s] a substantial reconsideration of the SMP program as a whole, [and proposes] material changes in how the program has been run, and what information [Peoples Gas] is required to report with respect to the program.” NS-PGL Ex. 12.0 REV at 18. The Commission should reject the AG’s proposals.

Mr. Eidukas explained that the SMP “has been the subject of multiple, extensively litigated Commission dockets” and that the Commission has, on multiple occasions, approved both Peoples Gas’ “project management approach to executing the SMP” and has found that the SMP “is necessary to protect the safety of Chicagoans and the reliability of their natural gas supply.” *Id.*

Peoples Gas has since proceeded to execute the SMP consistent with the Commission’s guidance in Docket Nos. 16-0376 and 18-1092, and it continues to make significant progress toward replacing at-risk pipe, thereby increasing safety and reliability for its Chicago customers, and, as of the end of 2022, has completed over one-third of that work. *Id.* at 20–21. Nor is this just about safety for PGL’s customers or the rest of Chicago’s residents and visitors; it is also critical for the safety of the unionized gas workers who work each day to maintain the city’s gas distribution system. Local 18007 Ex. 1.0 at 5; Local 18007 Ex. 2.0 at 6.

In addition to the proceedings in Docket Nos. 16-0376 and 18-1092, SMP has been independently audited. Mr. Eidukas explained that as a result of the Commission’s Order in Docket No. 14-0194, Liberty Consulting Group conducted a two-phase, multi-year, top-to-bottom audit of the SMP in 2015 through 2017. NS-PGL Ex. 12.0 REV at 21. Mr. Eidukas reported that “Peoples Gas has implemented and continues to follow the recommendations from the Liberty Consulting reports on the SMP. The changes implemented in response to these reports were significant and touched on virtually every aspect of the SMP.” *Id.* at 21.

Companies witness Eldringhoff likewise rebutted the AG’s calls for an overhaul of SMP. Ms. Eldringhoff explained that if adopted, those proposals “would threaten Peoples Gas’ [ ] ability to continue accelerated main replacements in the City of Chicago to address imminent safety and reliability issues associated with operating one of the oldest natural gas delivery systems in the country.” NS-PGL Ex. 14.0 REV at 18. Ms. Eldringhoff emphasized the danger of “materially rework[ing]” SMP in a rate case, and the critical
need for “a clear and certain regulatory framework [that] supports the project to enable the utility to make the requisite long-term investments and plans to ensure the safety and reliability of the distribution system.”  Id. at 18. Clearly, the proposals to revisit these settled SMP issues on a rate-case-by-rate-case basis would do just the opposite and create inappropriate regulatory uncertainty.

Ms. Eldringhoff provided multiple, concrete examples of problems that could arise from adopting the AG’s new SMP-related proposals in this case (Id. at 22–24) and demonstrated that Peoples Gas’ current approach is practical, efficient, and complies with Commission guidance.  Id. at 21–22, 27.

SMP project management issues have received extensive attention from the Commission, Staff, and multiple independent engineering firms, as well as being the subject of multiple ongoing Commission proceedings to review expenditures and related issues. The Companies argue that wholesale re-evaluation of SMP project management in this and presumably future rate cases would undercut those historic and current efforts, duplicate process, and reduce regulatory certainty. No intervenor provides any cost-benefit analysis, other persuasive evidence, or citation to appropriate legal authority that would justify using this rate case proceeding as a vehicle to materially modify the structure of the SMP and the existing regulatory framework in which it is continually reviewed and assessed. Of course, such mid-stream changes would in all likelihood delay the SMP, an outcome that the Commission, and independent engineers reviewing the SMP at the Commission’s behest, have cautioned against. See Docket No. 16-0376, (where the Commission stated in its evaluation of SMP timing that “safety and reliability are paramount to completing this project” by the 2035-2040 target date); NS-PGL IB at 91–92 (citing the Kiefner Study submitted to the Commission in Docket No. 18-1092, which stated that “the replacement rate has not been fast enough to compensate for the increase in failure rates expected from the aging system.”).

While certain intervenors in briefing speculate that the sunsetting of the Rider QIP statute somehow overrides the Commission’s, Staff’s, and outside engineers’ and auditors’ review of the SMP, they fail to cite to any legislative statement in support of this review. The AG and PIO point to P.A. 102-0662 — in the AG’s case alleging that P.A. 102-0662 is purported evidence that Illinois is “addressing these issues head-on” — but neither the AG or PIO can point to any provision of P.A. 102-0662 that addresses the QIP statute, SMP issues, or, in fact, any natural gas-related issues that intervenors have raised in this case, because P.A. 102-0662 is silent on those issues. If P.A. 102-0662 spoke directly to any specific issue in this rate case, the Commission could be certain that within the hundreds if not thousands of pages of written testimony and briefs submitted in this case, at least one party would have been able to point to a provision of P.A. 102-0662 that addresses these issues “head-on.” That has not occurred for a clear reason: P.A. 102-0662 does not address those issues.

Finally, the City emphasizes a single sentence contained in People ex rel. Raoul v. Ill. Commerce Comm’n, 2019 IL App (1st) 180679-U, as the basis to overhaul the SMP. That citation does not support the expansive proposals advocated by the City and other intervenors. As a threshold matter, the cited order was explicitly issued pursuant to Illinois Supreme Court Rule 23, and therefore (as indicated directly above the order’s case caption) “may not be cited as precedent by any party except in the limited circumstances
allowed under Rule 23(e)(1).” People ex rel. Raoul, 2019 IL App (1st) 180679-U. None of the Rule 23(e)(1) exceptions appear to apply (and in offering its citation to People ex. rel. Raoul, the City has not argued otherwise). Further, as to the substance, it is a vast over-reading of the highlighted sentence to suggest, as the City does, that the Appellate Court, which was not presented with the question, was somehow green-lighting the City’s proposal for a wholesale reevaluation of the SMP, including, inter alia, the requirement for Peoples Gas to perform a “Joint Feasibility Assessment,” an assessment of “the potential for strategic electrification and retirement of leak-prone pipe,” an analysis of “the costs and benefits associated with the SMP,” and analysis of “whether all aspects of the SMP … are still warranted,” to name just the SMP-related reevaluation steps that the City advocates. COC IB at 20–21. Nor, of course, was the Appellate Court approving the various other, sometimes conflicting, SMP-related proposals offered by other intervenors in this case, such as additional investigations, the creation of additional metrics, and even an actual suspension of the SMP pending the outcome of brand-new investigations.

In summary, the Companies state that the SMP as currently designed and implemented has been — and remains — the subject of rigorous regulatory oversight. Any suspensions, investigations, or other efforts to layer-on additional regulatory and evaluative burdens will slow the SMP execution, increase cost, and heighten rather than reduce the safety of Peoples Gas’ customers and work force. Accordingly, the Commission should reject intervenor proposals regarding SMP management issues.

(ii) AG’s Position

The AG argues that the record shows that enhanced annual reporting and review requirements are needed, and that the Companies should adopt industry best practices, which are necessary because their integrity management, program prioritization and budgeting lack regulatory transparency and fail to align with both best practices and the state’s new energy policies. The AG asserts that the Commission is authorized to adopt all or some of the recommendations, which are a direct result of and stem from its witnesses’ analyses of the Companies’ deficiencies in program management.

The AG contends its proposals are not general policy disagreements, and that the record shows them to be directly derived from, and a result of, its witnesses’ data-driven analyses of the Companies’ plant investments and integrity management practices.

Industry Best Practices

According to the AG, its review of the Companies’ rate request identified various shortcomings that establish that: (1) PGL lacks the data to understand and rank risks to its system; and (2) the backlog of QIP reconciliations (currently reviewing PGL’s 2016 expenditures) as well as the Companies’ collective resistance to providing even basic information make it impractical and nearly impossible to sufficiently review their spending proposals. See AG Ex. 3.00 at 27-34. The AG’s recommendations apply to PGL’s SMP and to the Companies’ other investments and expenses. Among the deficiencies the AG’s witnesses identified are PGL’s failure to track its leaks by cause and “sub-cause”; the absence of meaningful cost-benefit and alternatives analyses; and large budget variances showing a lack of cost discipline.
To address these deficiencies, the AG asks the Commission to order North Shore and Peoples Gas to incorporate best practices set forth by Mr. Walker. Specifically, the AG asks the Commission to order the Companies to:

- **Develop a comprehensive plan and budget.** Before starting infrastructure replacement program work, it is essential that a utility develop a comprehensive plan that outlines the scope of the program, appropriately identify infrastructure for replacement or other remediation, and develop a budget based on sound forecasting methodologies for each project defined in the program. This budget should remain static as the target to hit and as the benchmark to which performance may be compared at the project/program’s conclusion. A program with an effective budget process will be able to accurately forecast common, known costs and will be able to stay within a reasonable variance of budget for most uncommon or unforeseen project costs.

- **Implement effective cost controls.** Infrastructure replacement programs can be costly and cost-creep from the original budgeted amount can lead to unacceptable unit costs and total program costs. During and after developing a reasonable budget, effective cost control measures for projects in the program such as competitive bidding, cost tracking, change-order management, and value-engineering, can help to minimize expenses and ensure that the program stays within budget. A program that has effective cost controls will not have to rely on excessive change orders and will be able to account for costs through clear and transparent cost tracking.

- **Use data-driven decision-making to carefully prioritize projects.** Infrastructure replacement programs typically involve many discrete projects, such as mains, services, and associated equipment, each with different priorities. It is essential to prioritize these projects based on factors such as safety, regulatory compliance, and the condition of the infrastructure. Data analytics should be used to make informed decisions on infrastructure replacement projects. Data such as the age of the infrastructure, the number, type, and severity of leaks and resulting repairs, the specific cause of the leak, and maintenance history can help to determine which infrastructure component requires replacement first. A program that has effectively prioritized projects will be able to achieve demonstrable results without widespread cost overruns.

- **Monitor progress and Benchmark performance.** It is essential to continually monitor the progress of the infrastructure replacement program. This involves typical program activities such as tracking costs, timelines, and quality control to ensure that the program is on track to meet its goals and is installed correctly to plans and regulations and safety. It is also important to evaluate the utility’s program performance against peers’ programs to see how cost-effective the program has been at mitigating aging infrastructure. A cost-effective program is one that is able to achieve promised results without excessive cost overruns. When benchmarked against peers and/or the industry as a whole, a cost-effective program will compare favorably.
AG Ex. 3.00 at 27-29. The AG avers that its recommendations set forth below in this Section incorporate these best practices.

**Integrity Management, Project Prioritization, Leak Reporting**

Mr. Walker testified that integrity management ("IM") encompasses all actions, programs, procedures, processes, and activities undertaken by the Companies to maintain their safe and reliable systems. See AG Ex. 2.00 at 13. He testified that it is one of the primary mechanisms through which a threat or risk to a utility’s natural gas system is identified, evaluated, ranked, and addressed—in order of importance—through monitoring, repair, or replacement. Id.; see also PGL Ex. 14.0 REV at 25-26. According to Mr. Walker, "In a case where an [IM] program has effectively targeted the riskiest, most leak-prone pipe in the system, there is typically a decline in leaks caused by corrosion and material failure." AG Ex. 3.00 at 18-19. For PGL, Mr. Walker indicated that the data shows increases in the percentage of leaks attributed to these causes, and testified that PGL “has never had a method of reliably tracking leaks by sub-cause, and still does not.” AG Ex. 7.00 at 15. He added that “PGL’s employees and/or contractors do not properly fill out the cause of the leak in the asset management system” (id. at 15) and indicated that these failures have a tremendous impact on risk management and risk ranking that is contrary to every best practice he has encountered for tracking leaks (see AG Ex. 3.00 at 20; PGL Ex. 14.0 REV at 25). In short, the AG argues that without accurate and meaningful information—which PGL does not provide or collect—no effective solutions are available.

Regardless of whether PGL tracks leaks and threats to its system, the AG asserts that leak trend analysis shows rising hazardous leak rates, comprised of corrosion and material failure, and rising total leaks. According to the AG, this is evidence that PGL’s infrastructure replacements over the last decade failed to target its most leak-prone materials, and that changes are required moving forward to correctly address such LPP in PGL’s system.

Mr. Walker performed a ten-year trend analysis of total leaks, leak cause, and leak severity to gain a perspective on total leaks on the system, and in particular, the impact that the QIP has had on leak severity and origination. According to Mr. Walker, PGL and most utilities in the United States, grade leaks with an industry standard system that identifies the severity of a leak (on a scale of 1, 2, or 3, with 1 being the worst type) and the actions required to mitigate, make safe, and monitor them. AG Ex. 3.00 at 17, citing the “Gas Pipeline Technical Committee Guide.” In order to improve transparency, measure the effects, and gauge performance and leak results from the Companies’ investments, the AG asks the Commission to order the Companies to report leaks by Grade, cause and sub-cause, and facility type (i.e., material type and type of infrastructure), on an annual basis or at a minimum, with each rate recovery filing. The AG also asks the Commission to direct the Companies to report any changes in the way leaks are classified to ensure an accurate analysis of their performance. AG. Ex. 3.00 at 9, 12. The AG states that leak reports are critical to enabling the Commission to assess the scope of leaks on the system, and whether the Company is accurately identifying, targeting, and remedying those parts of its system in the most cost-effective manner. As such, the AG requests the Commission prohibit the Companies from classifying leaks in the “Other” category absent justification.
State Policies and Regulatory Review

Mr. Walker testified that since the record establishes that PGL still has a significant amount of LPP on its system, it will be important for PGL to have more typical rate case oversight that will review detailed leak data to evaluate IM spending with data-driven analysis. AG Ex. 3.00 at 38. Additionally, AG witness Dismukes testified about the need for higher scrutiny of capital investments to enable effective regulatory review and align the Companies’ infrastructure investments with Illinois’ new energy laws and decarbonization goals. He referred to actions in other jurisdictions at the state level (e.g., Colorado, New York, Rhode Island) to support his recommendation that Illinois require NS and PGL to provide comprehensive, annual, infrastructure plans that include important project details (e.g., cost, reasoning, and analyses of alternatives) prior to obtaining regulatory approval. AG Ex. 2.00 at 27-26; AG Ex. 6.00 at 4-5. Dr. Dismukes explained that this planning and reporting of larger cost investments is necessary to address the dangers of potentially stranded assets over the long-term as the state pursues carbon-free energy sources and reduces its reliance on fossil fuels. AG Ex. 6.00R at 14.

Dr. Dismukes recommended the Companies be required to seek a CPCN for major, new natural gas lines or non-reliability related natural gas infrastructure projects that exceed $12 million and that “do not address the most critical system needs (i.e., Grade 1 and Grade 2 leaks).” AG Ex. 2.00 at 27. This recommendation is discussed in detail in Section IV.B.5.b below. The AG explains that given the state’s commitment to decarbonization, it believes the Commission should review any such costly major projects from the Companies that would expand its natural gas infrastructure in potential conflict of the state’s goals. Dr. Dismukes’s recommendation would enhance the Commission’s visibility into these types of capital spending by the Companies, and give opportunities for the Commission and stakeholders to intercede and challenge projects inconsistent with best practices and public policies. AG Ex. 2.00 at 29.

The AG believes its recommendations represent an optimal path forward towards implementing the oversight necessary. PGL, however, generally complains that the AG’s recommendations are “extremely inefficient,” “expensive,” and “dramatic changes,” and that they could “set off a cascade of delays and extra costs.” PGL Ex. 12.0 REV at 18. The AG argues that these contentions are without merit.

Capital Plan and Reporting Requirements

Dr. Dismukes and Mr. Walker recommended the Commission adopt filing and reporting requirements. Specifically, the AG asks the Commission to adopt the following recommendations set forth below in (A)-(F):

A) Annual Transmission and Distribution Infrastructure Plan

The AG recommends that the Companies include the following information:

For Planned Projects

- Identification of all projects with anticipated cost in excess of $2.5 million either as a distinct project or as a collection of related sub-projects planned for the year, including:
characterization of infrastructure type;
reason for installation/replacement (i.e. growth, reliability, or safety);
project risk score;
specific risk remediated by the project;
project's anticipated construction start date and date those facilities are anticipated to be placed in service;
reason for the pace of project/program (i.e. reason why project/program cannot be deferred to future years);
unit cost estimates for small project groupings and methodology used by the Company to forecast future unit costs; and
detailed cost estimates.

For Completed Projects

• Budgeted versus actual expenditures for each major project (i.e., a project costing in excess of $2.5 million either as a distinct project or as a collection of related sub-projects) completed in the prior year;

• Explanation for all variances of 10 percent or greater including dollar amounts for each and every item, element, and/or driver of the variance, and an explanation of efforts undertaken by the Company to minimize the magnitude of each variance and any steps taken to plan for and/or avoid the occurrence of each variance in future years;

• List of all previously planned major projects that were subsequently deferred and not completed by the Company, as well as a list of new projects not previously planned by the Company for the year but executed that year;

• The number of change orders for each major project, the dollar amount associated with each change order, and a narrative description of the reason(s) for each change order; and

• Copies of the Company’s most recent integrity management plans, such as the Distribution Integrity Management Plan ("DIMP") and Transmission Integrity Management Plan ("TIMP").

The AG notes that these recommendations are consistent with Mr. Walker’s minimum filing requirements for future capital recovery requests, outlined below in Recommendation (B) and in his direct testimony. See AG Ex. 3.00 at 33.

B) Capital Recovery Request Filing Requirements

The AG recommends that the following minimum filing requirements accompany all future requests for capital recovery by the Companies:

• Detailed cost estimates for each major project, with a final “projected” budget to be identified and retained at the point construction bids are received and before materials procurements or construction work begins. This budget shall not be modified further;
• Unit cost estimates for small project groupings and methodology for forecasting future unit costs;

• Project cost tracking accounting – including change orders and modifications to project scope.

• Characterization of infrastructure type, reason for installation/replacement, specific risk remediated by project, and reason for pace of projects/programs.

• For projects that meet a materiality threshold to be established:
  o Alternatives & non-pipes analysis,
  o Expected service life,
  o Consideration of the risk of stranded assets, and
  o Full cost-benefit analysis

C) Leak Reporting Requirement

The AG recommends the Companies adhere to the leak reporting requirements discussed above.

D) MAOP and Records Compliance Plan

The AG asks the Commission to direct North Shore to formalize and file a MAOP and Records Compliance Plan for complying with the MAOP Rule on reconfirmation and records verification before proceeding with further replacement work for MAOP reconfirmation or material verification.

According to the AG, the plan should identify specific ways in which North Shore will utilize opportunistic sampling, regular integrity assessments, and other means of reconfirming MAOP and verifying records across the two compliance periods of now-2028 and 2028-2035. The AG states that the plan will ensure that compliance is reached in the allowed increments while allowing for maximum cost efficiency by utilizing existing and lower-cost activities to reconfirm MAOP where it is missing.

The Plan should also demonstrate how North Shore has followed the PHMSA directive to take a least-cost opportunistic approach to verifying materials and reconfirming MAOP. To the extent that North Shore still believes that replacement is the only option or the most cost-effective option for certain segments, the AG recommends that it should include a thorough analysis for each such alternative method for compliance including cost, rate impact, and operational feasibility considerations.

In addition to the MAOP and Records Compliance Plan, the AG recommends that for each request for capital recovery for compliance work under the PHMSA rules, it be accompanied by a demonstration of consistency with the MAOP and Records Compliance Plan on a per-project basis and include an alternatives analysis when pipe replacement is proposed.

E) CPCN Filing Requirement

The AG recommends the Companies adhere to the CPCN filing requirements mentioned above and discussed in further detail in Section IV.B.5.b. below.
F) Cap on Cost Per Mile for Distribution of Mains

The AG recommends the Companies adhere to the cost recovery cap per mile to replace distribution main mentioned above and discussed in further detail in Section IV.B.5.b below.

(iii) City’s Position

The City supports the AG’s positions with respect to program management.

(iv) PIOs’ Position

PIO support the AG’s recommended reporting requirements and spending control measures.

PIO state that, in light of the potential impacts of electrification on Peoples Gas’ system in the future, the Commission should take action in this proceeding to discipline the Company’s capital spending and ensure that capital spending is translating to performance going forward. PIO thus request that the Commission adopt the AG’s proposed reporting requirements and spending control measures.

(v) Commission Analysis and Conclusion

The Commission adopts the AG’s recommendation to order the Companies to annually report leaks by Grade, cause, and facility type (i.e., material type, age, and type of infrastructure). North Shore and PGL shall also fully define its “Other” leak category as identified in AG witness Walker’s direct testimony so these leaks can be accurately categorized, assessed, and appropriately remedied. The Commission agrees with the AG that such reporting will improve transparency, measure the effects of, and gauge performance and leak results from the Companies’ investments.

North Shore shall formalize and file a MAOP and Records Compliance Plan (“Compliance Plan”) to demonstrate compliance with the MAOP Rule on reconfirmation and records verification before proceeding with further replacement work for MAOP reconfirmation or material verification. The Compliance Plan shall identify specific ways in which the Company will consider, prioritize, and utilize the six methods for reconfirmation across the two compliance periods of present-2028 and 2028-2035. The Compliance Plan will ensure the Company’s reconfirmation efforts maximize cost efficiency using existing and lower-cost activities to reconfirm MAOP where necessary.

The Compliance Plan shall demonstrate how the Company followed the PHMSA directive to take a least-cost, opportunistic approach to verifying materials and reconfirming MAOP. To the extent that North Shore still believes that replacement is the only option or the most cost-effective option for certain segments, it shall include a thorough analysis for each such alternative compliance method, including at a minimum, cost, rate impact, and operational feasibility considerations. Each request for capital recovery for compliance work under the PHMSA rules shall be accompanied by a demonstration of consistency with the Compliance Plan on a per-project basis and include an alternatives analysis when pipe replacement is proposed.

The Commission addressed the SMP in section IV.B.1.a.(v). The Commission declines to initiate all of the new reporting requirements or spending controls or other requirements in this rate case except as described above.
The Commission finds the AG’s specific proposal in this docket to impose additional CPCN requirements conflicts with 220 ILCS 5/8 406. The AG’s request is denied. The AG’s proposal to require a spending cap per mile is also rejected. Such a cap would limit the Commission’s discretion to evaluate the Companies’ costs based on the individual circumstances presented by each project or set of costs.

2. Construction Work in Progress (PGL only)
   a. Companies’ Position
      (i) CWIP for South Shop

Peoples Gas’ rate base includes CWIP for the new South Shop in the amounts of $8.0 million as of December 31, 2023, and $55.6 million as of December 31, 2024. PGL Ex. 2.2 REV at Sch. B-7. The AG proposes an adjustment to rate base that would remove the average of these amounts ($31.8 million) because the new South Shop will not go into service until 2025. AG Ex. 1.0 at 4; AG Ex. 3.0 at 49; AG Ex. 5.0 at 6; AG Ex. 5.01 PGL at Sch. A2.

Peoples Gas opposes this adjustment. The South Shop will be in service, and thus used and useful, by June 30, 2025. NS-PGL Ex. 19.0 at 25. Accordingly, it qualifies for inclusion as CWIP in rate base pursuant to Section 9-214(e) of the Act, which provides: “the Commission may include in the rate base of a public utility an amount for CWIP for a public utility’s investment which is scheduled to be placed in service within 12 months of the date of the rate determination.” 220 ILCS 5/9-214(e).

AG witness Selvaggio interprets this language narrowly to mean that unless the South Shop is placed in service by November 29, 2024 (a year after the deadline for a Final Order in this case), it does not qualify for inclusion in CWIP. AG Ex. 5.0 at 5–6. Her proposed interpretation of the statute does not make logical sense in the context of future test year rate cases. If adopted by the Commission, it would prohibit the inclusion of capital going into service during the test year itself, which in this case runs through December 31, 2024, if and to the extent the rate Order is issued before the test year begins. This recommendation would tie the public utility’s rate base not to the test year in question, but rather to when the utility files its future test year case and how quickly the Commission could issue its decision.

Instead, the Commission has historically construed Section 9-214(e), including in cases involving Peoples Gas, to include projects going into service within a reasonable time tied to the test year. In the Companies’ opinion, this interpretation makes logical sense because the rate base is determined by the average (i.e., midpoint) of spend forecasted to be going into service during the twelve-month test year, or the middle of the test year. For CWIP, twelve months out from the midpoint of a calendar year test year is June of the following year.

In PGL’s most recent 2015 rate case (Docket Nos. 14-0224/14-0225), PGL adjusted its filed rate base to remove six capital projects scheduled to go into service more than six months after the test year. AG Cross Ex. 4.0 at NS_PGL_036321 (Sch. B-2.2) (listing these six projects), NS_PGL_036292. N. Shore Gas Co. and Peoples Gas Light & Coke Co., Docket Nos. 14-0224/14-0225 (cons.), Order (Jan. 21, 2015). Remaining was one capital project (a Phase 2 Emergency Shutdown System (“ESD
System”) upgrade) scheduled to go into service within six months of the test year. Id. at NS_PGL_036328 (Sch. B-7.1) (listing this project), NS_PGL_036286. PGL’s 2015 Commission-authorized rate base included the CWIP associated with that project. Similar adjustments were made in the 2021 rate case. Id. at NS_PGL_036381 ("North Shore has identified four projects that will not be completed and placed in service before July 2022; therefore, those amounts are being removed from rate base.") , NS_PGL_036423 (Sch. B-2.1) (listing these four projects). Remaining was one capital project (the Waukegan Shop) scheduled to go into service within six months of the test year. Id. at NS_PGL_036431 (Sch. B-7.1) (listing this project), NS_PGL_036382. After determining that construction of the project would not be completed within that time frame, North Shore agreed to remove that project’s CWIP from rate base, too. Id. at NS_PGL_036453 AG, NS_PGL_036473 (agreeing to adjustment), NS_PGL_036492 (reflecting adjustment).

In reliance on this understanding of the Commission’s rate case treatment of CWIP, Peoples Gas took the same approach to South Shop CWIP in this case. Notably, Staff has not contested this approach or proposed a corresponding adjustment. Peoples Gas states that the Commission should reject the South Shop CWIP adjustment proposed by the AG.

(ii) CWIP for SMP Investments

People's Gas states that, based on a similar (but more complicated) premise, the AG proposes eliminating from Peoples Gas’ 2024 revenue requirement certain SMP pipeline replacements that AG witness Walker asserts will not go into service until 2025.

As initially proposed in testimony, this would result in a rate base disallowance of $116.9 million out of the $234.3 million in 2024 spend. AG Ex. 3.0 at 39–40; NS-PGL Cross Ex. 13.0 REV. At Peoples Gas' proposed rate of return on common equity, this would represent a $6.6 million reduction to 2024 rates. NS-PGL Ex. 13.0 at 20. To be clear, this initial proposal, for the most part, was not a CWIP issue, but a dispute over whether capital expense Peoples Gas included in rate base for 2024 will in fact be used and useful in 2024. Mr. Walker’s initial proposed adjustment to 2024 rate base was based on an overly narrow standard for when gas pipeline replacements become used and useful. Under his proposed standard from testimony, pipelines would not be considered “in service” until three key milestones are met: (1) new pipelines are gassed up; (2) services are switched over from the old pipeline to the replacement pipeline; and (3) the old pipeline is taken out of service. AG Ex. 7.0 at 5.

According to Peoples Gas, Mr. Walker provided no support in statute, rule, or prior Commission decision supporting his proposal. His third criterion is problematic and makes no sense in the context of the safety investments Peoples Gas is making through its distribution pipeline replacement program. The first two criteria are satisfied for $229.0 million of the $234.3 million in 2024 SMP investments at issue, and there is no reasonable basis to dispute that a replacement gas pipeline is in service once it is gassed up and services are switched over to that pipeline, as the asset is clearly being used and is useful. NS-PGL Ex. 25.0 at 6. Moreover, all three of Mr. Walker’s proposed criteria, including having the old pipeline removed from service, are satisfied for over $136.5 million of the new SMP investment included in the 2024 test year, as shown in NS-PGL Ex. 25.01. NS-PGL Ex. 25.0 at 6; NS-PGL Cross Ex. 13.0 REV. So even the AG cannot argue for an
exclusion from rate base as to these projects. Consistent with the Uniform System of Accounts, Peoples Gas places new main in service, and begins associated depreciation, as it is gassed. For accounting and rate purposes, placing new main in service is completely independent of retiring old main that has been taken out of service. The date of retirement of the old main is completely irrelevant when considering whether the new main is used and useful in the provision of utility service and thereby eligible for inclusion in rate base. Peoples Gas states that Mr. Walker has not identified any authority or accounting standard supporting his position that new pipe cannot be considered “in service” until the pipe it is replacing has been retired. Id. at 6–7.

The AG itself now appears to agree with Peoples Gas on this point, as the AG’s Initial Brief abandoned the much larger $116.9 million proposed disallowance of 2024 SMP investment, i.e., those costs for new pipelines that will be gassed and switched over in 2024. The AG now recommends disallowing only the CWIP in rate base, a $5.3 million rate base adjustment. PIOs’ position appears to be the same. Both the AG and PIO still frame this as a contested distribution capital project in rate base. Peoples Gas explains that this would be true as to the SMP pipelines going into service in 2024, which Mr. Walker previously had advocated disallowing based on other criteria. Now that the AG (echoed by PIO) has limited the proposed disallowance to pipe going into service in early 2025, that is exclusively a CWIP issue. That adjustment appears to be based solely on the AG’s preferred reading of the CWIP statute, and (like the South Shop CWIP adjustment) Staff does not support it.

Based on this change in position, the CWIP dispute in this case encompasses a very small subset of pipeline replacement costs relating to projects where the last segment will be gassed between January 1 and June 30, 2025. These projects are listed on NS-PGL Cross Ex. 13.0 REV with a “Final gassing finish year” of 2025. Because each of the projects will be gassed by June 2025, Peoples Gas included these projects in its 2024 rate base consistent with the Commission’s historical ratemaking treatment of capital investment, as discussed in Section IV.B.1. NS-PGL Ex. 25.0 at 7. Peoples Gas asserts that the Commission should approve these along with PGL’s other SMP investments for inclusion in test year rate base.

b. AG’s Position

(i) CWIP for South Shop

The AG asks the Commission to adopt the recommendation of AG witness Selvaggio and remove CWIP costs for PGL’s South Shop because it will not be in service during the 2024 Test Year. The AG notes that Section 9-214(e) of the Act allows a utility to include CWIP costs in rate base for an “investment which is scheduled to be placed in service within [twelve] months of the date of the rate determination.” 220 ILCS 5/9-214(e). As the deadline for Commission action on the Final Order in this docket is November 29, 2023, CWIP costs may be included in rate base for projects that are scheduled to be placed into service by November 29, 2024 (or twelve months after the Final Order). AG Ex. 5.00 at 5. However, Peoples Gas expects its South Shop to be placed into service on June 30, 2025, or nineteen months after the Commission’s rate determination in this docket. NS-PGL Ex. 19.0 at 25. The AG thus asks the Commission to reject PGL’s proposal to include CWIP for the South Shop in rate base.
Ms. Selvaggio also recommended that the property taxes for the South Shop be capitalized to the cost of the project until the project is placed into service, rather than be included in the test year cost of service. According to the Uniform System of Accounts for Gas Utilities Operating in Illinois, taxes on physical property (including land) may be included in construction costs until the facility becomes available for service. Id. at 6-7; see also 83 Ill. Adm. Code 505. In surrebuttal testimony, PGL witness Zgonc agreed with Ms. Selvaggio that the 2024 property taxes related to the construction of the South Shop should be capitalized rather than expensed (NS-PGL Ex. 24.0 REV02 at 13) and as a result, PGL added the 2024 property tax expense of $0.730 million to the capitalized cost of the South Shop on December 31, 2024. NS-PGL Ex 24.01P REV at Sch. 1.02 at7, Sch. 1.04P at1. The Company’s surrebuttal adjustment increased the average test year rate base by $0.365 million for the 2024 property taxes. NS-PGL Ex. 24.01P REV at Sch. 4. However, since Ms. Selvaggio requests that the South Shop be removed from CWIP in its entirety, the AG argues that the related property taxes should also be removed from the Company’s cost of service. See NS-PGL Cross Ex. 20.0.

In response, PGL claims that the AG’s interpretation of this section of the Act “does not make logical sense in the context of the future test year rate cases” because “it would prohibit the inclusion of capital going into service during the test year itself, which in these cases runs through December 31, 2024.” NS/PGL at 59.

The AG argues its interpretation of the statute is based on the plain language of the Act, which explicitly limits rate base recovery of CWIP costs to “within [twelve] months of the date of the rate determination.” 220 ILCS 5/9-214(e). The Illinois Supreme Court has made clear that “the primary objective in construing a statute is to ascertain and give effect to the intent of the legislature” and “[t]he plain language of the statute is the most reliable indication of legislative intent.” Sheffler v. Commonwealth Edison Co., 2011 IL 110166, ¶ 75. The AG notes that when interpreting a statute, neither the Commission nor the courts should “depart from the plain language of the statute by reading into it exceptions, limitations or conditions that conflict with the legislative intent.” See id. According to the AG, PGL wrongly asks the Commission to ignore the plain meaning of the Act to allow CWIP to be included in rate base for a project that will not be in service within twelve months of the Commission’s Final Order. PGL’s request thus violates the plain language of the Act.

PGL argues that the Commission has historically construed this Section of the Act “to include projects going into service within a reasonable time tied to the test year.” NS/PGL IB at 59. According to PGL, this should include projects going into service as late as “twelve months out from the midpoint of a calendar year test year,” meaning June of the following year—or 2025. Id. To support this claim, PGL states that the Commission approved CWIP for one capital project that was scheduled to go into service six months after the test year in PGL’s last rate case. Id. However, a review of that Order reveals no statement or discussion allowing CWIP into rate base so long as it is in service six months after the end of the future test year.

PGL also cites North Shore’s testimony in its 2020 rate case to show that North Shore planned to include in rate base a project set to be in service six months after the test year, but in that case, North Shore withdrew its proposal before the briefing stage of that proceeding. Id. In short, the AG contends that the Companies’ so-called supporting
cites are their own proposals. The Companies’ proposals were withdrawn (North Shore) or not acknowledged by the Commission. In other words, the AG iterates that the issue was not raised in either instance, meaning the Commission had no reason to address or interpret Section 9-214(e) of the Act in connection with the cost. The AG asserts that the Commission’s order on an uncontested element in one case and North Shore’s withdrawal of a similar request in another does not constitute historical construction of the relevant section of the Act.

The AG maintains that PGL’s claim that the Commission has historically construed this Section of the Act “to include projects going into service within a reasonable time tied to the test year” is patently false. In PGL’s 2012 rate case, the AG notes the Commission held that “[a]s long as there is a preponderance of evidence that the projects that are being funded by CWIP will be placed in service within [twelve] months from June of 2013, inclusion in rate base of CWIP-funded projects is proper.” *N. Shore Gas Co. and Peoples Gas Light & Coke Co.*, Docket Nos. 12-0511/0512 (cons.), Order at 65 (June 18, 2013). The Final Order in that case was issued on June 18, 2013, meaning that the Commission based CWIP costs on a date twelve months from its Final Order — not six months after the test year as PGL claims. The AG points out that the Commission reached a similar decision in Commonwealth Edison’s 2010 rate case. *Commonwealth Edison Co.*, Docket No. 10-0467, Order at 30 (May 24, 2011). The AG thus contends there is no support for PGL’s claim that the Commission has “historically construed” this language to mean “projects going into service within a reasonable time tied to the test year.” NS/PGL IB at 59. According to the AG, the plain language of the Act as well as the Commission’s orders on this issue demonstrate that CWIP may only be included in rate base for projects that will go into service within twelve months of the Commission’s Final Order.

For these reasons, the AG requests the Commission reject Peoples Gas’ proposal to include CWIP for the South Shop in rate base. The AG’s adjustment reduces the average balance of CWIP in rate base by $31.783 (the average of the $8.0 million CWIP on December 31, 2023, and $55.566 million on December 31, 2024) (AG IB Attach., PGL, Sch. A2) and $0.365 million in associated property taxes (AG IB Attach., PGL, Sch. A3) for a total disallowance of $32.148 million ($31.783 + $0.365).

(ii) **CWIP for SMP Investments**

The AG asks the Commission to disallow $5.3 million in distribution plant because PGL admits eight projects will not be gassed up and placed in service until 2025. Peoples Gas identified 134 projects in distribution plant for the 2024 test year. PGL Ex. 3.1, Sch. F-4 at 1, Note (1). AG witness Walker discovered that several projects had a “Construction Completion Date” of 2025. AG Ex. 3.00 at 40. The AG states that PGL admitted that eight projects totaling $5.3 million have a “Final Gassing Finish Year” of 2025, which means that the last segment of these projects will not be gassed until 2025, will not be placed into service, and thus will not be used and useful in the test year. PGL Cross Ex. 13.0 REV (AG DR 13.01 Attachment 01PGL REV); PGL Ex. 25.1. The AG thus request the Commission disallow $5.3 million in proposed spending associated with these eight projects.
c. **CUB/PCR’s Position**

CUB/PCR support the adjustment sponsored by AG witness Selvaggio to remove CWIP expenses for the test year associated with amounts that AG witnesses propose be removed from rate base. See AG Ex. 5.0 at 5-6. This adjustment reduces PGL’s revenue deficiency by $2.95 million. AG Ex. 5.01 PGL, Sch. 5.

d. **The City’s Position**

The City supports the AG’s position with respect to CWIP for the South Shop in this case.

e. **Commission Analysis and Conclusion**

The AG asks the Commission to adopt its recommendation and remove CWIP costs for Peoples Gas’ South Shop because it will not be in service during the 2024 Test Year. Section 9-214(e) of the Act allows a utility to include CWIP costs in rate base for an “investment which is scheduled to be placed in service within [twelve] months of the date of the rate determination.” 220 ILCS 5/9-214(e). The AG states that since the deadline for a rate determination order in this docket is November 29, 2023, CWIP costs may be included in rate base for projects that are scheduled to be placed into service by November 29, 2024 (or twelve months after the Final Order). However, Peoples Gas expects its South Shop to be placed into service on June 30, 2025, or nineteen months after the Commission’s rate determination in this docket. The AG thus asks the Commission to reject PGL’s proposal to include CWIP for the South Shop in rate base. The AG requests the following adjustments that reduces the average balance of CWIP in rate base by $31.783 (the average of the $8.0 million CWIP on December 31, 2023, and $55.566 million on December 31, 2024) and $0.365 million in associated property taxes (AG IB Attach., PGL, Sch. A3) for a total disallowance of $32.148 million ($31.783 + $0.365).

Peoples Gas opposes this adjustment for the South Shop. The Companies state that in prior cases the Commission has allowed projects to be included as long as they were put into service within a reasonable time tied to the test year. The Companies do not cite any cases that support their position.

The AG also requests that the Commission disallow $5.3 million in distribution plant because PGL admits eight projects will not be gassed up and placed in service until 2025. People Gas also opposes this adjustment because each of the projects will be gassed by June 2025, Peoples Gas included these projects in its 2024 rate base consistent with the Commission’s historical ratemaking treatment of capital investment.

The Commission interprets Section 9-214(e) of the Act to mean that an investment in a project that will be placed in service within 12 months of the rate determination can be included in the rate base of a public utility. 220 ILCS 5/9-214(e). The Commission finds that the South Shop does not meet this criteria and the proposed costs are not approved to be included in rate base. The AG’s adjustment reduces the average balance of CWIP in rate base by $31.783 (the average of the $8.0 million CWIP on December 31, 2023, and $55.566 million on December 31, 2024). The Commission is not including the $0.365 million in capitalized 2022 property taxes related to the construction of the South Shop. Further, given the Commission decision in Section IV.B.d.(v) relating to Peoples...
Gas’ Shops and Facilities, including the South Shop, 2024 property taxes related to the construction of the South Shop shall not be included in rate base. The Commission will also adopt the $5.3 million adjustment for the eight projects identified by the AG and which Peoples Gas admits will not be placed in service until 2025.

3. Net Retirement Benefits
   a. Pension Balances
      (i) Companies’ Position

   Another significant contested item for both Companies is the rate base treatment of net retirement benefits, consisting of pension balances and other pension and employment benefits (“OPEB”) balances. The Companies argue that both pension and OPEB balances should be included in rate base, regardless of whether those balances are positive or negative, because the balances benefit customers and the balances were funded by shareholders. The Companies believe the time has come for the Commission to revisit its historical approach to rate base treatment of pension and OPEB balances.

   With respect to pension balances, Schedule B-1.2 (NS Ex. 2.2 REV; PGL Ex. 2.2 REV) includes two categories of accounts relating to pension for both Companies. For North Shore, those accounts are (1) Net Pension Funded Status (line 3), which has an average credit balance of $16.1 million, and (2) Net Pension/Welfare Reg Asset/(Liability) (line 6), which has an average debit balance of $2.1 million. NS Ex. 2.0 REV at 40. For Peoples Gas, those accounts are (1) Net Pension Funded Status (line 5), which has an average balance of $17.7 million, and (2) Net Pension Reg Asset/(Liability) (line 11), which has an average debit balance of $150.6 million. PGL Ex. 2.0 REV at 43.

   For both Companies, the first account is predominantly the actuarially calculated liability of the pension obligation net of fair value of the assets in the plan. NS Ex. 2.0 REV at 40, PGL Ex. 2.0 REV at 43. For North Shore, the second account relates to the overall net gains and losses of the plan. NS Ex. 2.0 REV at 40. For Peoples Gas, the second account is predominantly an asset created as a result of WEC acquiring Integrys. The Companies explain that during an acquisition, Generally Accepted Accounting Principles (“GAAP”) accounting requires a full re-valuation of the pension plan. Here, that re-valuation resulted in expenses that Peoples Gas was allowed to defer as part of the merger docket (to be amortized over the average remaining life of the plan at that time). The other Deferred Regulatory Assets and Liabilities – Pension relates to the overall net gains and losses of the plan. PGL Ex. 2.0 REV at 43–44. The Companies deferred these amounts as prescribed by FERC Order 883 AI107-1-000. These accounts will naturally unwind over the life of the plan. NS Ex. 2.0 REV at 40, PGL Ex. 2.0 REV at 44.

   According to the Companies, these items should be included in rate base. For each of these items, the Companies must fund the associated balances with their capital structure. To the extent the pension balances earn a return outside of the ratemaking process, that return is utilized to lower the overall pension expenses included in the proposed 2024 revenue requirement, which lowers costs for customers. These balances also reflect the fact that between 2015 and 2021, North Shore contributed over $20.0 million and Peoples Gas contributed over $420.0 million of shareholder dollars into their
Historically, the Commission has excluded from rate base any net debit pension balances (less their related deferred taxes). The Companies explain that if the net pension balance is a credit, that net credit typically has been included in rate base in the past. While Staff and CUB/PCR/City make much of this traditional approach in their testimony, the Commission should take a fresh look at this issue based on the evidence presented in this proceeding, and the Companies should be allowed to include all of these balances in rate base regardless of whether their balance is a net debit or net credit. NS Ex. 2.0 REV at 40, PGL Ex. 2.0 REV at 44. The Companies note that the Commission is not bound by res judicata and can adjudicate freely with each situation as it comes before it, regardless of how it may have dealt with a similar or even the same situation in a previous proceeding. NS-PGL RB at 26 (citing Miss. River Fuel Corp. v. Ill. Commerce Comm’n, 1 Ill. 2d 509, 513 (1953)). That leaves more than ample discretion for the Commission to consider whether, in this case, the record justifies rate base treatment of these balances based on customer benefit, funding by shareholders, or both.

Staff’s and CUB/PCR/City’s primary position is that Commission precedent requires excluding pension balances from rate base unless the Companies can demonstrate that the balances were funded with shareholder dollars. Staff witness Alan claims Peoples Gas has failed to submit evidence proving shareholder funding, while CUB/PCR/City witness Gorman purports to offer evidence to prove that Peoples Gas has not used investor capital to fund its pension asset. Staff Ex. 2.0 at 11-12; CUB/PCR/City Ex. 1.0 at 13-14. NS and PGL contend that these arguments miss the mark on multiple levels.

First, the “shareholder funding” test fails to account for the Commission’s traditional approach to negative pension balances, which is to include those balances in rate base — presumably because doing so reduces overall rate base and thus lowers the revenue requirement. This approach includes pension balances in rate base when doing so benefits customers — the same test the Companies propose here. Notably, in this case, Staff says nothing about North Shore’s negative pension balance, but Staff only raises the “shareholder funding” test when a pension balance is positive, such that including it in rate base would increase the revenue requirement. The Companies assert that is plainly inconsistent.

Regardless, if the test for rate base treatment of pension balances is proving shareholder contributions, the Companies clearly meet it. The Companies’ last approved rates did not include any amounts to fund their pension balances, yet the Companies made significant contributions to the pensions since 2015. Those contributions were necessarily funded with investor capital — in the case of Peoples Gas, over $420.0 million in shareholder capital over four years alone. NS-PGL Ex. 13.0 at 7.

The Companies state that Mr. Alan appears to believe that unless the Companies can produce evidence that they raised capital specifically for the purpose of funding future pension contributions and can track those dollars from investors to the pension fund, then the Commission must conclude that the funding came from ratepayers and disallow recovery. However, the Companies argue, that assumption is not reasonable. On the
contrary, as a practical matter, once a utility’s rates are set, the utility must use the revenue it actually receives to operate the business and, with any money left over, provide a return to its investors through dividends. In this proceeding, we know that funding for pension contributions was not included in the Companies’ last approved rates. So once the Companies had funded their operating expenses, they had a choice whether to return the net revenue to investors or reinvest some portion of it in the business. The Companies elected to strengthen their pension plan through incremental pension contributions with dollars that could have been returned to investors. This demonstrates that investors took a lower return on capital to fund pension contributions outside of approved recovery in rates. This is what is meant by funding the pension contributions from the Companies’ “capital structure.” NS-PGL Ex. 13.0 at 7–8.

Staff witness Ebrey recharacterizes this as a choice by Peoples Gas to use “revenues provided through rates to fund the pension by its own admission.” Staff Ex. 10.0 at 5–6. In the Companies’ view, this focus on rate revenue misses the point. It assumes there is no such thing as a “shareholder dollar.” In other words, because a utility’s operating revenues are received from customers through rates in the first instance, all of the utility’s operating revenues can only ever be “customer dollars,” regardless of how the utility deploys those revenues thereafter. This fundamentally misunderstands how a utility funds its operations, capital outlays, and shareholder returns out of its capital structure. Again, the dollars the utility collects through rates must both recover the utility’s operating and capital expenses and provide shareholders a reasonable return on their investment. The “return” is what remains after the utility’s operating expenses are paid and capital investments made out of the revenues the utility received. Critically, the hundreds of millions of dollars that the Companies have contributed to their pension funds since 2015 were not included in their revenue requirement when rates were set—meaning that if the Companies elected to make those contributions anyway, they would necessarily come out of the portion of the rate set aside for shareholder returns. NS-PGL Ex. 24.0 REV02 at 8.

Ms. Ebrey’s view of pension funding also proves too much according to the Companies. It could be applied to any traditional capital investment that the Companies undertake to benefit customers. The Companies could always opt to devote less rate revenue to funding capital investments, instead retaining more earnings and passing them along to shareholders. When instead the Companies “choose” to invest revenues in new utility infrastructure for the benefit of customers (instead of funding the investment with debt), the Commission does not disallow those investments because the Companies “chose” to use “ratepayer dollars” to fund them. Rather, the Commission asks whether the investment was prudent, reasonable, and used and useful in serving customers. If Ms. Ebrey’s position were correct, it would mean that no use of rate revenues to reinvest in the Companies would ever qualify for recovery in future rates. The more reasonable view is that when the Companies significantly reduce investor return of capital to invest in their workers instead, rate recovery should follow. Id. at 8–9.

Staff and CUB/PCR/City raise two more arguments specific to the shareholder funding question. One (from Staff) is that Peoples Gas only contributed $240.0 million, not $421.3 million, to its pension fund. Staff Ex. 10.0 at 6. The Companies explain that this point relates to the role of the Employee Retirement Income Security Act, (“ERISA
4044”) reallocation of assets due to a plan split in 2017. Ms. Ebrey is correct that $181.3 million of PGL’s total contribution was the result of this reallocation. However, she is incorrect that this was not a “real” contribution. As reflected in NS-PGL Ex. 24.03, the dollars reallocated to PGL’s pension fund were paid for by Peoples Gas with real money and increased actual pension funding by a corresponding amount. The Companies state that the fact that those funds initially came from the former Integrys Energy Group Retirement Plan (“IEGRP”) does not change the fact that those dollars were funded by Peoples Gas outside the revenue requirement when contributed. Even setting aside this $181.3 million, Peoples Gas still contributed another $240.0 million to the pension fund. ERISA reallocation does not account for that significant contribution, and Staff identifies no other basis to exclude it from rate base. NS-PGL Ex. 24.0 REV02 at 9–10.

The other argument (from CUB/PCR/City) is that Peoples Gas has already recovered its pension contributions from customers because its approved rates include revenue requirement for pension expense. CUB/PCR/City Ex. 1.0 at 13–14. The Companies argue that the Commission should reject this argument for several reasons.

First, Mr. Gorman claims that Peoples Gas has been recovering $32.05 million per year in pension expense since its last rate case. Assuming that is true, that recovery was granted to offset the annual service cost of the plan net of its expected return on assets (“EROA”), not to offset shareholder contributions to the pension fund. As Staff witness Alan points out, pension expense and pension contributions are not the same thing. Staff Ex. 2.0 at 11; NS-PGL Ex. 13.0 REV at 9.

Second, even if Mr. Gorman’s math were correct and his $352.0 million were applied to offset pension contributions (instead of annual pension expense, as it does now), that still would not account for $69.3 million in shareholder contributions — and it would leave a corresponding amount of pension expense unfunded. NS-PGL Ex. 13.0 REV at 9.

Third, over and above those problems, Mr. Gorman’s $352.0 million figure is not even correct. There are nine years from 2015 through 2023. At $32.05 million per year, the amount “recovered” would be $288.45 million, or 68.3% of the $422.4 million funded. That leaves $133.95 million not yet recovered from customers. If Peoples Gas were to recover $17.0 million per year in rates beginning in 2024, it will take almost eight years to recover the remaining balance. As such, even under this mistaken theory, shareholders are still funding a nine-figure balance in pension contributions. Id.

NS and PGL state that faced with these errors, Mr. Gorman pivoted in rebuttal, now arguing that because pension expense is a non-cash expense, including that expense in the revenue requirement allows the Companies to use the cash from corresponding rate revenues to offset other cash expenses, in this case their pension contributions. CUB/PCR/City Ex. 3.0 at 11–14. However, the Companies argue this position is without merit, as substituting depreciation (another non-cash expense) for pension expense makes clear. Further, the amount included in rates for pension expense comes nowhere close to the amount of the pension contributions at issue. Again, it would take eight more years for shareholders to recover the balance, with no return in the interim. The Companies state this directly contradicts Mr. Gorman’s statement that “Peoples [Gas’] cash contributions to its pension trust will be fully recovered by Peoples
[Gas] during the period rates determined in this proceeding will likely be in effect" (CUB/PCR/City Ex. 3.0 at 14), and Mr. Gorman never addresses Mr. Zgonc’s calculation in his testimony. NS-PGL Ex. 24.0 REV02 at 11–12.

The same goes for Mr. Gorman’s suggestion that pension contributions might have been recovered through pension expense in rates in even earlier periods. Again, the Companies explain, regardless of the period at issue or how long it continues, rate recovery for pension expense does not constitute recovery for pension contributions. Instead, as long as the revenue requirement included nothing for pension contributions, customers contributed nothing to the pension. The same will be true in the future unless and until the Commission approves inclusion of pension contributions in rate base; otherwise, customers will not “continue to make cash contributions to the pension trust in this proceeding” any more than they have in the past. Beyond this, Mr. Gorman makes no attempt to offer the Commission any calculation or documentation supporting any of these reassurances. Id. at 12.

The Companies state that pension balances benefit customer and this matters because if the Commission is considering whether customers should support pension balances in rate base going forward, then how the pension balance was historically funded is only one part of the analysis. First, the pension fund is a long-term incentive held in trust for the benefit of workers who are themselves likely customers of the Companies. Second, the pension fund enables the Companies to retain their key resources—their employees—for many of the same reasons as the other long-term incentives Mr. Zgonc described in his direct testimony (PGL Ex. 2.0 REV at 60–75), and as Mr. Olsen further described in his rebuttal testimony (NS-PGL Ex. 21.0 at 8–10). Customers, in turn, benefit when the Companies retain quality employees based on the promise of financial stability that a pension provides. Third, the EROA generated by the pension fund lowers costs for customers by directly reducing both rate base and the cost of servicing the pension, i.e., pension expense. NS-PGL Ex. 13.0 at 12.

This third point supporting rate recovery is particularly important in the Companies’ view. Again, there is a distinction between pension contributions, which are made by investors and are not included in rates, and pension expense, which is the expense of maintaining the pension and is included in rates. While recovery for the latter does not pay for the former, there is an important relationship between the two: as contributions to the pension fund increase, so does the EROA (which, again, is the fund’s expected return). The Companies explain that EROA, in turn, has two benefits for customers—both of which would not exist without the pension balances, and both of which lower customer bills. The Companies’ calculation of pension expense includes an offset for the EROA, which reduces net pension expense and thus reduces the test year revenue requirement. Also, the EROA reduces overall rate base, which reduces rates well beyond the test year. Id. at 12–13.

Under the arbitrary and capricious standard, the pension and OPEB balances are not separable from the EROA benefits they generate. The Companies submit that a Commission decision to remove retirement benefit balances from rate base but still retain EROA benefits for customers would be totally inconsistent treatment from both an accounting and a ratemaking perspective. If the Commission concludes that the expense
and rate base reductions enabled by these balances are a benefit to customers, then the balances themselves should remain in rate base for that reason. Conversely, if the Commission concludes that the pension and OPEB balances should be excluded from rate base, then any returns they generate should be reinvested into those balances, not used to reduce rate base and rates. *Id.* at 16–17.

In addition, if the Commission declines rate base treatment for the Companies’ pension balances, other adjustments would be necessary. The Companies would still need to be compensated for the cost of maintaining the pension asset on their balance sheets. This is a significant asset, and the Companies follow GAAP in accounting for it. The Companies state that they cannot avoid financing their balance sheet, including this item. In this circumstance, the cost of doing so for the pension balance should be funded at the weighted average cost of debt, as determined by the Commission in this proceeding. Again, the same should be true for the OPEB balances. *Id.* at 17.

The Companies point out that in contrast to the debate over shareholder funding, no party responded to any of the Companies’ testimony regarding the significant and concrete customer benefits provided by the pension balances, and no party contested the Companies’ position that if the Commission concludes these balances are not benefiting customers, then consistency would also require an adjustment to restore significant expenses currently being offset by the internal returns on those balances. NS-PGL Ex. 24.0 REV02 at 7.

In light of this comprehensive and unrebutted testimony, the Commission should revisit its traditional position in this case and allow rate base treatment of North Shore’s and Peoples Gas’ pension balances.

(ii) **Staff’s Position**

Staff asserts that disallowances from rate base for Peoples Gas’ (a) pension asset and (b) related ADIT are required since Peoples Gas has failed yet again to show the pension asset was created by shareholders. The record in this case, as it has in the past, shows the pension asset was funded by ratepayer funds. Staff Ex. 2.0 at 11; Staff Ex. 10.0 at 4. Staff’s position is in accordance with multiple Commission orders, for both Peoples Gas and other Illinois utilities in which the Commission has repeatedly held that shareholders are not entitled to a return on ratepayer-supplied funds. The Companies want the Commission to revisit and disregard that standard in all those orders for a “new standard.” The “new” standard is “customer benefits.” NS-PGL Ex. 13.0 at 18. Staff urges the Commission not to act inconsistently with its prior orders as Peoples Gas suggests without providing a reasoned basis for doing so. The evidence in this record provides no reasoned basis for the Commission to now start allowing the pension asset in Peoples Gas’ rate base.

Peoples Gas rejects the Commission’s prior holdings that the pension asset was created with ratepayer funds. The specifics of Peoples Gas’ position in this case have been presented and rejected several times in the past. Peoples Gas states that it must fund its pension balances with its “capital structure” and further opines that it has “contributed over $420 million of shareholder dollars into the pension plan.” PGL Ex. 2.0 REV at 45-46. Staff asserts that the Companies provided no evidence that the contributions were made from any source other than normal operating revenues. In
response to Staff DR MA 3.14 (Staff Ex. 2.0, Attach. B) requesting support for its position that the contribution was funded solely by shareholders, the Company stated:

Peoples Gas’ base rates did not include pension contributions; therefore, any contributions to the pension plan were made from shareholder dollars per the Commission’s Final Order in Docket [Nos.] 14-0224/14-0225 (cons.).

Staff Ex. 2.0 at Attach. B. That response only refers to rates approved in Docket Nos. 14-0224/0225 (cons.). It does not address whether rates approved in prior orders and subsequent orders include a recovery for pension expense. The response also confuses pension contributions with pension expense. Pension contributions and pension expense are not the same. In addition, and most importantly, pension expense can be negative. Since pension expense can be negative, the fact that pension contributions may be greater than pensions expense does not mean that contributions have been greater than the pension expense recovered through rates. Staff Ex. 2.0 at 11. Staff states that nothing in the referenced Commission Order supports the Companies’ conclusion that contributions to the pension plan were made from shareholder dollars. To the contrary, the Commission Order in Docket Nos. 14-0224/14-0225 (cons.) agreed with Staff’s position that the pension plan was funded by ratepayers. Docket Nos. 14-0224/14-0225 (cons.), Order at 49 (Jan. 21, 2015). In addition, the Companies admit that “[s]ince 2015, neither Peoples Gas nor North Shore raised funds specifically to fund pension plans.” Staff Ex. 2.0 at Attach. C.

According to Staff, the Companies want the Commission to look past its prior orders on this pension asset issue. The Companies want the Commission to ignore the order in Docket Nos. 09-0166/09-0167 (cons.), where the Commission denied inclusion of Peoples Gas’ pension asset in rate base since there was no evidence in the record it was created with shareholder funds. N. Shore Gas Co. and Peoples Gas Light & Coke Co., Docket Nos. 09-0166/09-0167 (cons.), Order at 36 (Jan. 21, 2010); People ex rel. Lisa Madigan v. Ill. Commerce Comm’n, Nos. 1-10-0654, 1-10-0655, 1-10-0936, 1-10-1790, and 1-10-1846 and 1-10-1852 (cons.), Ill. App. (1st) at 42-43, ¶ 69-71 (Sept. 30, 2011). Nowhere in that order did the Commission suggest a new standard of “customer benefits.”

Staff notes that the Commission again denied inclusion of the pension asset in the subsequent three North Shore Gas/Peoples Gas rate cases. See generally N. Shore Gas Co. and Peoples Gas Light & Coke Co., Docket Nos. 11-0280/0281 (cons.), Order at 33 (Jan. 10, 2012); N. Shore Gas Co. and Peoples Gas Light & Coke Co., Docket Nos. 12-0511/0512 (cons.), Order at 90 (June 18, 2013); Docket Nos. 14-0224/0225 (cons.), Order at 49. Nowhere in these orders did the Commission suggest a new standard of customer benefits.

Staff explains that the pension asset issue is not unique to Peoples Gas rate cases. It has been addressed in many other utility rate case orders. In five separate gas rate cases Nicor Gas sought to increase utility rate base for the amount of a prepaid pension asset. In all five cases, the Commission found that the pension asset was created by ratepayer-supplied funds, not by shareholder-supplied funds. See N. Ill. Gas Co. d/b/a Nicor Gas Co., Docket No. 21-0098, Order at 13-14 (Nov. 18, 2021); N. Ill. Gas Co. d/b/a
Nicor Gas Co., Docket No. 17-0124, Order at 28 (Jan. 31, 2018); N. Ill. Gas Co. d/b/a Nicor Gas Co., Docket No. 08-0363, Order at 18. (Mar. 25, 2009); N. Ill. Gas Co. d/b/a Nicor Gas Co., Docket No. 04-0779, Order at 22-23 (Sept. 20, 2005); N. Ill. Gas Co. d/b/a Nicor Gas Co., Docket No. 95-0219, Order at 9 (Apr. 3, 1996). In each case, the Commission concluded that shareholders should not earn a return on ratepayer funded assets. Accordingly, the Commission further concluded that the pension asset should be eliminated from rate base. Staff states that in none of those orders did the Commission suggest that it would consider a new test of “customer benefits.”

Staff notes that the Commission has also twice declined to include a pension asset in rate base for Illinois-American Water Company (“IAWC”). In Docket No. 11-0767, the Commission found that IAWC’s proposal to include a pension asset in rate base was not substantively different than those the Commission has considered, and rejected, in past rate case decisions. Ill.-Am. Water Co., Docket No. 11-0767, Order at 8. (Sept. 19, 2012). In Docket No. 16-0093, IAWC attempted to receive a debt return on its pension asset. The Commission denied the adjustment, citing IAWC’s past case history and the lack of new facts provided in that docket. Ill.-Am. Water Co., Docket No. 16-0093, Order at 12-13 (Dec. 13, 2016). Similarly, in Docket No. 14-0066, the Commission ruled against MidAmerican Energy Company when it proposed to include a pension asset in rate base, because the company failed to show that the pension asset was funded by anything other than ratepayer funds. MidAmerican Energy Co., Docket No. 14-0066, Order at 12. (Nov. 6, 2014).

In Docket No. 20-0308, Staff observes that the Commission ruled against Ameren Illinois Company d/b/a Ameren Illinois (“Ameren”) when it proposed to include an OPEB contra-liability (or OPEB asset) in rate base, because Ameren admitted these were not shareholder funds. The Commission ruled that Ameren’s proposal was “tantamount to a pension asset” and rejected the costs for recovery. Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 20-0308, Order at 13. (Jan. 13, 2021).

To support its customer benefit argument, the Company asserts that it contributed $421 million in cash to the pension plan since 2015. Staff Ex. 10.0 at 6. However, Staff witness Ebrey determined the Company actually only contributed $240 million, not $421 million. Id. Staff explains that the difference of $181 million resulted from an ERISA 4044 reallocation of assets due to a split of the pension plan in 2017. Staff Ex. 10.0 Attach. A provides support for Staff witness Ebrey’s conclusion. Id. Ms. Ebrey testified that based on her review of the Companies’ responses to discovery in this case, WEC split the IEGR into six plans as of January 1, 2017, to align with its regulatory entities. As a requirement of that split, the assets of the IEGR had to be reallocated to the various individual pension plans based on certain criteria. Staff Ex. 10.0 at Attach. A. As a result of that reallocation, an additional $181,307,061 was allocated to Peoples Gas and an additional $572,242 was allocated to North Shore. Those amounts are reflected in the actuarial study provided by Willis Towers Watson for 2017 as “Transfers” which increase the Fair Value of the Assets of Peoples Gas and North Shore as of the end of 2017. Staff Ex. 2.0 at Attach. B.

Staff witness Ebrey further testified that Peoples Gas and North Shore include those asset transfers in their amounts of “pension contributions” since June 2015. Staff Ex. 10.0, Attach. C. However, those payments were paid via wire transfer to Integrys
Energy Group, not to the pension trust. Staff notes this is further evidenced by the 2015–2024 actuarial reports which reflect the other pension contributions made by the Companies during that same period. Staff Ex. 10.0, Attach. B at at5, Change in Plan Assets, In. 3, Employer Contributions. Only the four payments totaling $240 million for Peoples Gas appear on those annual reports; the $181.3 million does not appear as a pension contribution. Staff Ex. 10.0 at 7.

Significantly Staff witness Ebrey testified that the $181 million resulting from the asset reallocation impacted the overall funded status of the pension plan. Peoples Gas provided to the parties a schedule of the asset transfers as of January 1, 2017 for the plan split. Staff Ex. 10.0 at Attach. D. The split which resulted in the $181.3 million that was ultimately transferred from Peoples Gas to WEC (and included by the Company in the $421 million total “contribution”) was the difference between the net balance sheet liability of ($334,801,832) before the split and the net balance sheet liability of ($138,073,919) after the split. According to that schedule, the pension plan for Peoples Gas reflected a pension liability both before the split and after the split. Staff states the funded status of the pension plan through the test year remains a pension liability. Staff Ex. 10.0 at Attach H.

Finally, as to the appropriateness of the Company’s proposed “new standard” of “benefit to customers,” Staff asserts that should not be the sole test for whether cost recovery is appropriate. NS-PGL Ex. 13.0 at 6. 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. Ill. Commerce Comm’n, 19 Ill. 2d 76, 85–6, 91 (1960); DuPage Util. Co. v. Ill. Commerce Comm’n, 47 Ill. 2d 550, 554, 558 (1971); Cent. Ill. Light Co. v. Ill. Commerce Comm’n, 252 Ill. App. 3d 677, 583 (3rd Dist., 1993); see also Bus. & Prof’l People for the Pub. Interest v. Ill. Commerce Comm’n (“BPI II”), 146 Ill. 2d 175, 258 (1991). Staff argues the Commission has consistently rejected the attempts of other utilities to receive a return on ratepayer-supplied funds and should do so again here. See, Citizens Util. Bd. v. Ill. Commerce Comm’n, 166 Ill. 2d 111, 132 (1995) (Commission is unauthorized to depart drastically from practices established in earlier orders); Miss. River Fuel Corp. v. Ill. 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).

(iii) AG’s Position

The AG asks the Commission to reject Peoples Gas’ proposal to recover the costs of its pension asset from ratepayers because this asset did not result from shareholder funds, and to adopt the recommendations of Staff witness Ebrey and the CUB/PCR/City witness Gorman to remove Peoples Gas’ claimed pension asset from rate base. Staff Ex. 10.0 at 8.

PGL argues that the Commission should permit it to recover its pension asset through rate base “because the balances benefit customers, and because the balances were funded with shareholder dollars.” NS/PGL IB at 63–76. But as the AG, Staff, and CUB/PCR/City point out, the Commission should reject PGL’s proposal because the Commission has consistently rejected similar utility proposals and PGL’s request is not distinct from these other proceedings. The AG indicates that the pension asset PGL
seeks to include in rate base is not distinct from these other proceedings, and that the Commission should thus reach the same conclusion here as it has in prior cases and reject PGL’s attempt to unfairly charge consumers a return on funds that were not supplied by shareholders.

The AG notes that Staff witness Ebrey’s adjustment is presented on Staff Sch. 10.01P. It reduces rate base by $120.311 million (a reduction of Retirement Benefits, Net by $168.279 million offset by a decrease in ADIT of $47.968 million).

(iv) CUB/PCR/City’s Position

For PGL, CUB/PCR/City propose adjustments to reflect Mr. Gorman’s recommended exclusion of the Companies’ net pension assets from rate base. Mr. Gorman’s proposal reflects the Commission’s exclusion of net pension assets from rate base in rate cases stretching back over a decade. This adjustment reduces PGL’s revenue deficiency by $11.088 million and increases North Shore’s revenue deficiency by $933,000, to reflect North Shore’s negative net pension asset balance. CUB/PCR/City Ex. 1.0 at 10-16.

Commission precedent establishes that a utility may include a prepaid pension asset in rate base only if the utility proves that its shareholders funded the pension asset. E.g., Docket No. 17-0124, Order at 29. CUB/PCR/City contend that Companies witness Zgonc admitted in testimony that the Commission historically has not allowed utilities to include prepaid pension assets in rate base. PGL Ex. 2.0 at 45. CUB/PCR/City point out that, to Mr. Zgonc’s point, Peoples Gas, North Shore, and other Illinois utilities repeatedly have litigated this issue before the Commission and consistently have lost.

Nevertheless, CUB/PCR/City note Mr. Zgonc argues that this time the Companies should be allowed to include their prepaid pension assets in rate base, though he does not claim any change in circumstances or applicable law. See PGL Ex. 2.0 at 45. Mr. Zgonc asserted that investors funded the prepaid pension asset, but CUB/PCR/City contend that no evidence provided in Mr. Zgonc’s three rounds of testimony, or anywhere else in the record, proves this assertion. CUB/PCR/City Ex. 1.0 at 12.

Mr. Gorman explained that the Companies’ prepaid pension asset can be initially funded by NS-PGL, but then the Companies can fully recover this pension trust funding cost by collections of pension expense from customers in the Companies’ cost of service; or the prepaid pension asset can be created by trust fund returns that exceed pension costs. Id. at 12-13. In either case, the pension asset is not funded by investor capital. Id. Only if the utility makes cash contributions to the pension trust and those contributions are not recovered from customers would the prepaid pension asset be funded by shareholders. CUB/PCR/City argue there is no evidence that this situation exists in this case.

CUB/PCR/City asked the Companies to identify the amount of actual pension contributions they made to the pension trust since their respective last rate cases. Id. at 14. In response, PGL stated that it made pension funding contributions in 2017-2021 totaling approximately $421.3 million. Id.; CUB/PCR/City Ex. 1.1. PGL stated that it has included in its last rate case an annual pension expense of $32.05 million per year. Id. Taken together, if this pension fund was in effect from 2015 through the test year in this
proceeding, Mr. Gorman calculated that PGL will have recovered roughly $352 million of pension expense from 2015 through 2024. CUB/PCR/City Ex. 1.0 at 14. This amount represents approximately 84% of the $421.3 million cash contribution PGL has made since 2015 and since the period the net pension asset was created in WEC’s acquisition of PGL’s then-parent corporation Integrys. Id. at 11, 14.

CUB/PCR/City explain that Peoples Gas requests $17 million, including capitalized costs, of pension expense in this year and is not projecting to make any cash contributions to its pension trust through 2024. Id. at 14. If PGL continues to recover approximately $17 million per year of pension expense, CUB/PCR/City calculate PGL will fully recover its cash contributions and pension expense during the period rates determined in this proceeding will be in effect. Id. That is to say, PGL has fully recovered, or soon will fully recover, all its cash contributions to its pension trust via collections from customers, per CUB/PCR/City’s calculations. Id. at 14-15. Thus, CUB/PCR/City contend PGL is not entitled to a return on those cash contributions. Id. at 15. CUB/PCR/City point out that the Commission made such a finding in PGL’s previous three rate cases. Docket Nos. 14-0224/14-0225 (cons.), Order at 49; Docket Nos. 09-0166/09-0167 (cons.), Order at 35-37; Docket Nos. 07-0241/07-0242 (cons.), Order at 36.

In response to the Companies’ claims that this approach conflates pension expense and pension cash contributions, CUB/PCR/City note that because the Companies recover regulatory pension expense in their ratemaking cost of service, they can both (1) recover its financial GAAP pension expense while rates are in effect and (2) increase its operating cash flows, which compensate the Companies for their cash contributions to the pension fund. CUB/PCR/City Ex. 3.0 at 11. CUB/PCR/City explain that thus recovering pension expense from customers both compensates the Companies for recorded pension expense and enhances their internal cash flow to compensate the Companies for cash contributions to the pension trust. Id. at 12. CUB/PCR/City also point out that the Companies base their claim that they have not fully recovered the referenced costs through rates on an incomplete record going back to only 2015.

In response to the Companies’ argument that the Commission should allow them to include pension balances in rate case because the balances benefit customers, CUB/PCR/City offer two responses. First, CUB/PCR/City respond that all of the benefits the Companies claim here are indirect and irrelevant to any customers. Second, CUB/PCR/City contend the Companies’ claims of ancillary customer benefit are beside the point. The obvious primary beneficiaries of the Companies’ pension assets are the Companies’ employees, who do or will receive pension payments, and the Companies, who use these funds to cover their pension liabilities. CUB/PCR/City argue the notion that customers should pay for the pension balance via rate base because they may indirectly benefit from the asset’s stability serves only to distract from the fatal flaw in the Companies’ reasoning. CUB/PCR/City conclude after all these years, the Companies still have failed to demonstrate that shareholders funded the pension balances and therefore should earn a return on it. CUB/PCR/City contend the record shows that ratepayers contributed to the value of the asset, and it does not establish the same for shareholders. CUB/PCR/City maintain asking ratepayers to pay a return on funds they provided in the first place, based on the assertion they may receive some indirect benefits that clearly
cannot rival the direct benefits that employees and shareholders derive, is unjust, unreasonable, and plainly unfair.

CUB/PCR/City conclude the evidence in this case does not support PGL’s proposal to earn a return on the prepaid pension asset. Therefore, CUB/PCR/City request that the Commission remove the net pension asset from PGL’s rate base and, so as to treat both Companies consistently, North Shore’s net pension liability should also be removed from rate base. This adjustment reduces PGL’s revenue deficiency by $11,088 million and increases North Shore’s revenue deficiency by $933,000. CUB/PCR/City Ex. 1.0 at 10-16.

(v) Commission Analysis and Conclusion

The Companies seek to include a pension asset in PGL’s rate base that they argue was supplied by shareholder funds. This argument was previously presented by the Companies in their last four rate cases. The Commission disallowed the inclusion of the pension asset in PGL’s rate base in all four cases. There has been no change in circumstances to support a deviation from the Commission’s prior analysis. While the Companies urge the Commission to revisit its traditional position relating to pension asset in rate base, any deviation from the Commission’s past rulings must be explained and supported. The Commission is not persuaded that its past treatment of pension assets suffered from flawed reasoning. Moreover, Commission decisions are entitled to less deference where they depart from past practices. City of Naperville, Docket No. 03-0799, Order at 38 (Sept. 9, 2004); Citizens Util. Bd. v. III. Commerce Comm’n, 683 N.E. 2d 938 (1st Dist. 1997). As in the four prior cases, the Companies have failed to provide sufficient evidence that the pension asset was created with shareholder funds. Consequently, the Commission adopts the recommendations of the AG, Staff, and CUB/PCR/City to remove the claimed pension asset from rate base.

A pension liability is the result of an underfunded pension plan. Removing North Shore’s pension liability from rate base would cause an increase in rate base allowing North Shore to effectively earn a return on the unfunded portion of its pension plan. It would not be appropriate ratemaking to incentivize a utility to underfund its pension obligations. The CUB/PCR/City position for North Shore is not adopted.

b. OPEB Balances

(i) Companies’ Position

The Companies note that only Staff opposes rate base treatment of the OPEB balances, contrary to the Commission’s historical treatment of such balances, and then only because these balances happen to be positive in the 2024 test year. Staff Ex. 2.0 at 17–18.

There is no principled basis for that distinction in the Companies’ view. The OPEB balances are funded the same way and do the same thing from rate case to rate case regardless of whether those balances are assets or liabilities. If the Commission has previously concluded that these balances qualify for inclusion in rate base in light of how they are funded and the purpose they serve, that conclusion should not change based on fluctuations in value. The Companies argue that the fact is that the OPEB balance is on the Companies’ balance sheet either way, and its rate base treatment should be
consistent to reflect that point. Notably, no other party is taking fully consistent positions on these balances—whether pension or OPEB, assets or liabilities. NS-PGL Ex. 13.0 at 19.

In rebuttal, Staff witness Ebrey maintained that excluding these particular OPEB balances from rate base is a matter of “consistency.” Staff Ex. 10.0 at 8–9. The Companies argue that this is wrong for at least two reasons. First, if Ms. Ebrey is correct that all that matters is who funded these balances, then by her own logic, OPEB balances (like pension balances) should be categorically excluded, because (again, by her logic) those balances were funded with “ratepayer dollars.” However, Ms. Ebrey does not adhere to that position for OPEB; instead, she defends a different approach whereby positive balances (“contra-liabilities”) are excluded, whereas negative balances (“liabilities”) are not. To the extent Ms. Ebrey maintains that distinction is consistent with Commission precedent, this only confirms that something other than “who paid” is driving the analysis after all. NS-PGL Ex. 24.0 REV02 at 10.

Second, the Commission has not “ruled consistently and independently” that rate base treatment for OPEB balances depends on whether the balance is positive or negative. In the Companies’ consolidated test year 2010 rate cases, the Commission found that it was “appropriate to treat Peoples Gas’ pension asset and North Shore’s pension liability consistently” (in that case, excluding both from rate base). Docket Nos. 09-0166/0167 (cons.), Order at 36. In Ameren’s 2014 formula rate proceeding, Docket No. 13-0301, the Commission rejected Staff’s proposed adjustment to remove Ameren’s OPEB “contra-liability” from rate base. Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 13-0301, Order at 35, (Dec. 9, 2013). That the Commission went the other way in Ameren’s test year 2021 rate case, as Ms. Ebrey points out, is evidence of inconsistency, not consistency. Staff Ex. 10.0 at 9.

The Companies are not “ignoring” the Order in Docket No. 11-0282, as Staff indicates; rather they argue that the Commission is not bound by that Order (see Miss. River Fuel Corp.) and point out that the Commission has come out differently in other cases. The key point is that whether the test is customer benefits, shareholder funding, or both, there is no principled reason to depart from that treatment depending on the sign of the balance.

Lastly, CUB, after focusing solely on pension balances in testimony, now argues for removing the positive OPEB balances from rate base, as well. The Companies speculate that perhaps this is in response to the Companies’ assertion that CUB was being inconsistent on this point. However, at the same time, CUB advocates for eliminating North Shore’s net pension liability from rate base, even though that balance is negative and Staff does not recommend that disallowance. It is a strange sort of “consistency” that would favor eliminating a net pension liability that lowers rate base (and thus rates) — especially coming from the designated consumer advocate in this case. The Companies contend that the Commission should reject these arguments and include the Companies’ OPEB balances, like their pension balances, in rate base.

In this proceeding, only the Companies have presented a rate base treatment that is consistent for both pension and OPEB balances, according to the Companies, regardless of whether those balances are positive or negative. Staff and CUB/PCR/City
Instead advocate for balance-specific, outcome-driven exceptions that prioritize rate reductions over any genuine attempt at fair and consistent treatment. NS-PGL Ex. 24.0 REV02 at 10–11. The Companies argue the Commission should avoid the traps of arbitrariness and capriciousness set by their arguments, and should approve inclusion of the Companies’ OPEB balances, like their pension balances, in rate base.

(ii) Staff’s Position

Staff states that the OPEB assets and related ADIT for both North Shore and Peoples Gas should not be included in rate base. Staff Ex. 2.0 at 17, Sch. 2.03 N and 2.03 P; Staff Ex. 10.0 at 8, Sch. 10.2 N and 10.02 P. The Companies failed to show that the assets were created with anything other than ratepayer funds. Staff Ex. 10.0 at 8. The Companies’ sole basis for their inclusion is that in the past OPEB liabilities have reduced/offset rate base therefore an OPEB asset should be included. PGL Ex. 2.0 REV at 45; NS Ex. 2.0 REV at 41. The Companies conflate decisions concerning removal of OPEB liabilities with decisions about including contra-liabilities in rate base. The Commission, based on the evidence in each proceeding, has ruled consistently and independently on the exclusion of contra-liabilities and the inclusion of liability balances. Staff states that the Commission has consistently ruled that OPEB liabilities should be included as rate base deductions as the liabilities represent a cost-free source of capital. For example, the Commission ruled against Ameren in Docket No. 11-0282, where Staff and other parties argued that the OPEB liability was a source of cost-free capital to the Company provided by ratepayers, stating:

In conclusion, the Commission agrees with the arguments of Staff and GCI. Consistent with past practice, AIC’s accrued OPEB liability shall be deducted from rate base. AIC’s analysis and the improper precedent it would establish are rejected.

_Ameren Ill. Co. d/b/a Ameren Ill., Docket No. 11-0282, Order at 19 (Jan. 10, 2012) (emphasis added)._  

The Companies ignore the case cited in Staff’s direct testimony which quotes the Final Order in an Ameren proceeding wherein the Commission agreed with both Staff and the AG that the OPEB “contra-liability” adjustment is tantamount to a pension asset and therefore should be removed from rate base. Staff Ex. 2.0 at 18 (citing Docket No. 20-0308, Order at 13). Staff’s position on the issue in the current case is consistent with the Commission’s prior treatment of an OPEB asset (contra-liability). In Staff’s opinion, no evidence has been presented in this case to cause the Commission to depart from that prior case conclusion.

Staff notes that the Commission considered and rejected this same argument by North Shore and Peoples Gas in Docket Nos. 07-0241/07-0242 (cons.). In Docket Nos. 07-0241/07-0242 (cons.), 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 it did not include in rate base. Peoples Gas similarly 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. Docket Nos. 07-0241/07-0242 (cons.), Order at 36. The Commission ruled in the same manner in the North Shore and Peoples Gas rate cases, Docket Nos. 11-0280/11-0281 (cons.), Docket Nos. 12-0511/12-0512 (cons.) and Docket Nos. 14-0224/14-0225 (cons.).

(iii) AG’s Position

The AG urges the Commission to remove Peoples Gas’ and North Shore’s claimed OPEB assets from rate base for similar reasons the AG provides for the pension balances. Like pension assets, the Companies claim that the Commission should permit recovery of the OPEB assets because the balances benefit customers and were funded by shareholders. The AG, Staff, and CUB/PCR/City argue that the Commission should reject the Companies proposals for similar reasons as the pension asset.

(iv) CUB/PCR/City’s Position

For PGL, CUB/PCR/City support Staff witness Mugera’s recommended $3.271 million revenue adjustment to reflect correct ratemaking treatment of OPEB contra-liabilities. Staff Ex. 2.0 at 17-19; Staff Ex. 1.0 at Sch. 1.05 P.

For North Shore, CUB/PBR/City supports Staff witness Mugera’s recommended $404,000 revenue adjustment to reflect correct ratemaking treatment of OPEB contra-liabilities. Staff Ex. 2.0 at 17-19; Staff Ex. 1.0 at Sch. 1.05 N.

(v) Commission Analysis and Conclusion

For the reasons identified for disallowing the inclusion of a pension asset in rate base, the Commission adopts the recommendations of the AG, Staff, and CUB/PCR/City to remove the Companies’ OPEB assets from rate base.

4. Cash Working Capital (Contested Elements)

a. Companies’ Position

The Companies state that cash working capital (“CWC”) is the amount of money that shareholders have provided to the utility to pay its current obligations. Investors are entitled to a return on that amount. Peoples Gas and North Shore conducted lead-lag studies to determine the level of CWC required to finance day-to-day operations. The “lag” portion of lead-lag studies determines the number of days between when service is rendered to customers and when the payment for those services is ultimately available to the Companies, known as the revenue lag period. PGL Ex. 10.0 REV at 4. The Companies explain that there are four components of revenue lag, which add up to the overall number of lag days: (1) service lag; (2) billing lag; (3) collections lag; and (4) bank float on collections from customers. Id. Only collections lag is disputed in this case. The longer the revenue lag period, the more CWC is required. The lead portion of lead-lag studies determines the amount of time between when goods are services are provided to the Companies and when suppliers are paid for goods and services. AG Ex. 1.00 at 7. The longer the lead period, the less CWC is required.

The Companies state that the lead-lag studies were based on their cash transactions and invoice data for the twelve months ended December 31, 2021, which was the last actual calendar year period available when the Companies filed their applications. Companies witness Addison calculated Peoples Gas’ overall lag to be 85.69
days and North Shore’s overall lag to be 50.37 days. NS-PGL Ex. 24.01P REV at Sch. 1.08 P; NS-PGL Ex. 24.01N at Sch. 1.08. The lead-lag studies concluded that the appropriate level of CWC required by Peoples Gas is $131.7 million, and by North Shore is $4.3 million, and those amounts are proposed for inclusion in rate base. PGL Ex. 10.0 REV at 3; NS Ex. 10.0 REV at 3; NS-PGL Ex. 24.01P REV at Sch. 1.08; NS-PGL Ex. 24.01N at Sch. 1.08. The Companies provided a comparison of the CWC requested in this case to the amounts allowed in their prior rate cases. PGL Ex. 10.0 REV at 3, NS Ex. 10.0 REV at 3.

Staff and intervenor witnesses proposed adjustments to the Companies’ CWC, including changes to collections lag; intercompany billing lead days, both generally and as applied to pension expense; non-pass-through taxes billing lead days; and O&M billing lead days. The Companies address each of these proposed adjustments below.

(i) **Collections Lag**

The amount of CWC required by Peoples Gas in test year 2024 is significantly more than was approved in the Companies’ 2015 rate case. PGL Ex. 10.0 REV at 3. The Companies state that the principal driver of the increased CWC requirement at Peoples Gas was an increase in the collections lag component of revenue lag. *Id.* at 4. One of the reasons the collections lag increased was because of the utility industry’s response to COVID-19, which included the Commission’s 2020 and 2021 emergency orders in Docket No. 20-0309 that stopped, for a time, disconnections and late payment charges, reduced reconnection payment thresholds and charges, reduced down payments for deferred payment arrangements, and allowed longer deferred payment arrangements. *Id.*

Staff witness Alan took issue with Peoples Gas’ calculation of collections lag. Mr. Alan testified that collections lag during the 2021 study period was artificially high due to various moratoria on collections activities resulting from Docket No. 20-0309, and therefore is not representative of what should be expected in the 2024 test year. Staff Ex. 2.0 at 6-7. To address this perceived deficiency in the study, Mr. Alan proposed using the average of three years’ collections lag: (1) the lag approved in the Companies’ 2015 rate case, which was based on a lead-lag study conducted in 2012; (2) the 2021 lag the Companies relied on to support their proposed CWC in this case; and (3) the collections lag calculated in an updated 2022 study produced during discovery. *Id.* at 8. This resulted in a collections lag of 52.68 days, which lowered the Companies’ overall lag from 85.69 days to 69.75 days. *Id.*

CUB/PCR/City witness Gorman also proposed an adjustment to collections lag, but unlike Mr. Alan, he advocated basing the calculation solely on the Companies’ test year 2015 lead-lag study, which was based on data collected over ten years ago, reasoning that collections in 2021 were skewed by the Commission’s actions in response to COVID-19. CUB/PCR/City Ex. 1.0 at 5-7. Mr. Gorman argued that “the lead-lag study from Peoples [Gas’] last base rate case, based on 2012 collection data, though dated, represents a more reasonable normalized bill collection period than that developed from the 2021 data.” *Id.* at 7. Mr. Gorman’s adjustment, if accepted, would reduce the overall revenue lag to 46.48 days. *Id.* at 8.
The Companies state that Mr. Alan’s and Mr. Gorman’s reliance on the 2012 lead-lag study improperly prioritizes a dated and stale study over much more recent data and therefore their proposed adjustments to collections lag should be denied. Specifically, the 2012 study was completed in a much different business and economic climate, when inflation was 1.7%, versus 7.0% during the 2021 study period. NS-PGL Ex. 18.0 at 5-6. The 2021 collection lag is in line with historic collections lags in 2018 and 2019, before COVID became a factor, refuting any contention that the 2012 lead-lag study better reflects pre-COVID conditions. *Id.*; NS-PGL Ex. 18.1. Notably, Staff did not agree with Mr. Gorman’s proposal to use the 2012 lead-lag study to forecast the test year revenue lag, reasoning that the proposal “overlooks changes and updates that have occurred since the last rate case.” Staff Ex. 9.0 at 13. Using the 2012 collections lag to calculate lag for the 2024 test year is, as Mr. Addison put it, “a choice designed to reduce Peoples Gas’[ ] revenue deficiency.” NS-PGL Ex. 18.0 at 6.

As for Staff witness Alan’s proposal to add the 2022 lead-lag study to the mix, Mr. Addison explained that 2022 was an outlier, with relatively short collections lag because of the unprecedented levels of Low-Income Home Energy Assistance Program (“LIHEAP”) and Utility Disconnection Avoidance Program (“UDAP”) grants available in that year. *Id.* at 4. LIHEAP and UDAP funds available to Peoples Gas’ customers increased from an average of $33.7 million in 2018-2020 to $78.4 million in 2022. *Id.* These funds allowed customers to pay their bills much more quickly in 2022 than in past years, reducing collections lag by almost ten days when compared to the prior four years. To the Companies’ knowledge, UDAP funds will not be available at all in the test year, and LIHEAP funds are expected to decline by over 40% in 2024 compared to 2022 levels. *Id.* While Mr. Alan noted that the disconnection moratorium ran through March 31, 2022, which all else being equal would tend to skew collections lag higher (Staff Ex. 2.0 at 7-8), the overall dramatically lower collections lag in 2022 cannot be denied. In the Companies’ view, both Mr. Alan’s and Mr. Gorman’s proposed collections lag methodologies are aimed at cherry-picking data to drive the collections lag lower, thus reducing CWC, and should be rejected.

In its Initial Brief, Staff claimed that the fact that collections lag in 2021 was similar to the lag in 2018 and 2019 contradicts Peoples Gas’ position that changes in collections and payment practices due to the COVID-19 pandemic and the Commission’s disconnections moratorium in Docket No. 20-0309 impacted collections lag in 2021. There are many variables that affect collections lag, but Staff is correct that the lags in 2018, 2019, and 2021 were similar (69.87, 70.79, and 68.52 days, respectively). However, the Companies state, if anything this fact cuts against Staff’s position that it would be appropriate to rely on collections lag data that is over a decade old to calculate 2024 lag. To the contrary, collections lag has been relatively stable in recent years, and therefore provides the best estimate of lag days that can be anticipated in the test year. Therefore, the record supports Peoples Gas’ calculation of collections lag, and does not support the forecasts advocated by Staff, the AG, or CUB/PCR/City.

Anticipating that the Commission may nevertheless be convinced that a multi-year average is a better means of calculating collections lag than using the 2021 lead-lag study, the Companies proposed a compromise position of using the three most recent years’ data. That would result in a collections lag for PGL of 62.22 days, and an overall
revenue lag of 83.39 days. NS-PGL Ex. 18.0 at 6-7. This methodology, relying on recent data, is more reliable than either Mr. Gorman’s reliance on twelve-year-old data, or Mr. Alan’s method of combining that same old data with two more recent years. To be clear, however, the Companies do not agree with Staff’s three-year average method, as Staff inaccurately states in its Initial Brief. In fact, Peoples Gas continues to advocate calculating collections lag using 2021 data only. However, to the extent the Commission is convinced that using an average to calculate collections lag is preferable to using one year, the Companies set forth an accurate, reliable calculation for the Commission’s consideration. This should not be read as agreement that the “average” approach is appropriate, but rather as a recognition that the Commission may find Staff’s position convincing and a desire to provide a more up-to-date average if that is the case.

Mr. Gorman did not respond to Peoples Gas’ compromise position directly (and likewise did not further defend his proposal to use the 2012 lead-lag study to set collections lag in 2024), but rather pivoted to criticizing Peoples Gas for not collecting from its customers quickly enough, arguing that this had led to greater collections lag. CUB/PCR/City Ex. 4.0 at 5-9. In particular, Mr. Gorman relied on the Commission’s decision in the Companies’ 2017 Rider UEA proceeding, Docket Nos. 20-0665/0666 (cons.), testifying:

the Commission accepted the [AG’s] arguments that the Companies did not act prudently during 4 to 12 months in 2017. During this period, the Commission found that the Companies did not meet their obligation to act reasonably. Indeed, the Commission found that the Companies did not act prudently and reasonably through suspension of disconnections in 2017 over a four-month period in 2017, and possibly much longer as disconnections were suspended for over a year while a customer information system upgrade was being implemented.

Id. at 8. However, Peoples Gas’ allegedly imprudent actions in 2017 have no bearing on the reliability of 2021 data, as (again) disconnections in 2021 were very close to their historical average in prior years. NS-PGL Ex. 29.0 REV at 6. In other words, Mr. Gorman has failed to show that any alleged imprudence in 2017 carried forward into 2021, as he would have to do to convince the Commission to accept a lead-lag study that is over a decade old as the basis for forecast collections lag in the test year.

Staff witness Mugera adopted Mr. Alan’s direct testimony on CWC but introduced new criticisms of the company’s methodology for calculating collections lag. Specifically, Mr. Mugera took issue with the PGL’s change from using cash collections data in the last rate case to using accounts receivable aging data in the 2021 lead-lag study, speculating that “this change in the information used in the calculation collections [sic] lag used in the revenue lag may be the cause for the increased collections lag days . . .” Staff Ex. 9.0 at 9-10. Second, he criticized the lack of collections data from 2013 to 2017 due to implementation of a new customer information system, arguing that “there is a gap of five years of missing information which is necessary to understand what happened since the last rate case.” Id. at 14-15. Finally, Mr. Mugera argued, without citing to any evidence,
that Peoples Gas had not normalized its collections data since implementing the new customer information system. *Id.* at 16.

The Companies assert that Mr. Mugera’s arguments are not persuasive. Since Peoples Gas’ last rate case, all of Illinois’ investor-owned gas utilities used accounts receivable aging data to calculate collections lag, and the Commission has approved this method in Nicor Gas’ last three rate cases (Docket Nos. 21-0098, 18-1175, and 17-0124), Ameren’s last three rate cases (Docket Nos. 20-0308, 18-0463, and 15-0142), and North Shore’s 2021 rate case (Docket No. 20-0810), where it was adopted without objection from Staff. NS-PGL Ex. 29.0 at 3-4. Indeed, the very same methodology was proposed for North Shore in this proceeding, and Staff has not opposed it. *Id.* at 5. As Mr. Addison testified, Peoples Gas examined these prior cases and adopted the accounts receivable aging data method based on its understanding that it was the widely accepted prevailing methodology in the industry. *Id.*, 4. Mr. Mugera has provided no justification for Peoples Gas to be treated differently from its peer utilities in this regard. As for the question of the “missing” data from 2013-2017, Mr. Mugera has offered nothing more than speculation that the data might help understand the increase in collections lag since the 2015 rate case. As Mr. Addison pointed out, Peoples Gas does not have any obligation to preserve that data, and Mr. Mugera has not identified any such obligation. *Id.* at 3. Finally, contrary to Mr. Mugera’s unsupported assertion, Peoples Gas had, in fact, normalized collections data since implementing its new customer information system in 2017. *Id.* at 5. Thus, none of Mr. Mugera’s positions support his recommendation on collections lag.

(ii) **Intercompany Billing Lead Days**

The Companies explain that the other side of the lead-lag coin is the calculation of lead days, which represent the time between when goods and services are provided to the Companies and when suppliers are paid for goods and services (i.e., how fast the Companies pay their bills). AG Ex. 1.00 at 7. A greater number of lead days reduces required CWC, all else being equal. AG witness Selvaggio focused on three aspects of the lead days calculation, beginning with intercompany billing lead days, which measure how long it takes the Companies to pay their service company, WEC Business Services (“WBS”), for goods and services. Ms. Selvaggio argued that any payment made before the very last day it is due represents cross-subsidization by the Companies of a non-utility affiliate. Staff witness Mugera agreed with Ms. Selvaggio’s criticisms on these three aspects of lead days. Staff Ex. 9.0 at 18–20.

The Companies further explain that payment terms for intercompany charges are dictated by the WEC Affiliated Interest Agreement (“AIA”). The AIA provides that “Each Receiving Party will pay outstanding balances by the end of the month following the availability of detailed information about the charges.” *Id.* at 7. Ms. Selvaggio concedes that this means that “payment dates are within the Companies’ discretion as long as the payment is made by the end of the month.” *Id.* at 8. Mr. Addison explained that intercompany transactions occur on a daily basis and are settled within 30 days. Therefore, the Companies use a midpoint approach to capture the average timing of transactions throughout the current month and deem the settlement date to be the 15th of the following month for purposes of the lead-lag study, thereby accounting for transactions that occur both earlier and later in the month. NS-PGL Ex. 18.0 at 9. Ms. Selvaggio takes the position, however, that any transaction settling on any date before...
the 30th day represents cross-subsidization. AG Ex. 1.0 at 8. Ms. Selvaggio proposes setting North Shore’s lead days at 45.40 lead days as opposed to the Companies’ calculation of 30.77 lead days, and Peoples Gas’ lead days at 45.54 lead days, compared to the Companies’ calculation of 30.56 lead days. Id. at 9.

Ms. Selvaggio relies heavily on the Commission’s decision approving WEC’s acquisition of the Companies’ parent company and the WEC AIA. In that decision the Commission found, consistent with 220 ILCS 5/7-204(b)(2), that “the proposed reorganization will not result in the unjustified subsidization of non-utility activities by the utility or its customers.” Wis. Energy Corp., Integrys Energy Grp., Inc., Peoples Energy, LLC, Peoples Gas Light & Coke Co., N. Shore Gas Co., ATC Mgmt. Inc., and Am. Transmission Co., LLC, Docket No. 14-0496, Order at 40 (June 24, 2015); AG Ex. 1.0 at 8; AG Ex. 5.0 at 18. That decision approved the WEC AIA as written, including its requirement that intercompany services be paid for within 30 days, not on the 30th day. The Companies state that they have discretion to manage payments within the confines of the Commission-approved AIA, and the Commission should not substitute its judgment for the Companies with respect to payments of intercompany expenses. Payments made in a timely manner and in accordance with corporate policy do not represent cross-subsidization.

Ms. Selvaggio argues that the Companies should not be allowed to have higher-than-required CWC as a result of paying affiliates faster than third parties (i.e., intercompany billing lead is less than Other O&M billing lead). AG Ex. 1.0 at 8; AG Ex. 5.0 at 19. In his rebuttal testimony, Mr. Addison identified an error in how Peoples Gas had calculated Other O&M billing lead, which, if corrected, would have been to the Companies’ favor; however, in order to simplify the issues in the case, the Companies did not pursue this correction. NS-PGL Ex. 18.0 at 11–12. The correct billing lead for Other O&M billing lead should have been 26.91 days for Peoples Gas and 33.11 days for North Shore — less than the intercompany billing lead, meaning that Ms. Selvaggio’s criticism of the relative speed of payments to affiliates and non-affiliates is unfounded. NS-PGL Ex. 29.0 REV at 8; NS-PGL Ex. 29.2. The Companies assert that the Commission should adopt the Companies’ calculation of intercompany billing lead days, as set forth in NS-PGL Ex. 24.01P REV at Sch. 1.08, and NS-PGL Ex. 24.01N at Sch. 1.08.

Staff witness Alan proposed to use 30.56 days as the intercompany billing lead for pension expense rather than the zero-expense lead that the Companies proposed, reasoning that this methodology has been adopted in prior Commission cases. Staff Ex. 2.0 at 4–5. This proposed adjustment is derivative of the larger dispute over treatment of pension expenses, which is addressed in Section IV.B.3. The Companies state that if the Commission adopts the Companies’ position on pension expense, then Mr. Alan’s adjustment should be rejected; if it does not, then the Companies do not dispute Mr. Alan’s proposed adjustment. NS-PGL Ex. 18.0 at 10.

(iii) Non-Pass-Through Taxes Billing Lead Days

The Companies state that they sometimes pay federal and state unemployment taxes, sales and use taxes, and property/real estate taxes before the very last day that they are due to (1) manage cash flow efficiently and (2) avoid potential late payment
penalties and interest due to missing a payment. NS-PGL Ex. 18.0 at 8. The Companies’ billing lead days for non-pass-through taxes are based on actual payment dates. Ms. Selvaggio takes the position that the billing lead days for non-pass-through taxes should be calculated based on their due date, regardless of when they are actually paid. AG Ex. 1.0 at 10. However, the Companies argue that Ms. Selvaggio ignores the Companies’ justification for paying early. The Companies have significant tax burdens, and the penalties for missing payment deadlines are likewise significant and would flow through to customers. Further, paying tax bills slightly before they are due mitigates unnecessary disputes as to receipt of tax payments. The Companies should not be penalized for prudently managing tax payments to avoid such penalties and interest. Therefore, NS and PGL assert that the Commission should adopt the Companies’ calculation of non-pass-through taxes billing lead days, as set forth in NS-PGL Ex. 24.01P REV at Sch. 1.08, and NS-PGL Ex. 24.01N at Sch. 1.08.

(iv) Other O&M Billing Lead Days

In her direct testimony, Ms. Selvaggio identified concerns with potential duplicate transactions skewing the calculation of Peoples Gas’ O&M billing lead days. AG Ex. 1.0 at 12. She recommended that Peoples Gas update O&M billing lead days in its rebuttal testimony. Id.

In response to Ms. Selvaggio’s concern, Peoples Gas identified some duplicate transactions. When they were removed, the result was an increase in the Other O&M billing lead days from 36.82 days as indicated in Mr. Addison’s direct testimony, to 38.40 days. NS-PGL Ex. 18.0 at 11; NS-PGL Ex. 18.2. The Companies state that Ms. Selvaggio remained unsatisfied with that calculation despite admitting that Mr. Addison had eliminated the duplicate transaction that she had identified and recommended that North Shore’s Other O&M billing lead days (43.17 days) be used for Peoples Gas. AG Ex. 5.0 at 22. Ms. Selvaggio has provided no evidence that duplicate transactions continue to skew the Other O&M billing lead days calculation, and her arbitrary proposal should be rejected. The Companies request that the Commission adopt Peoples Gas’ corrected calculation of 38.40 Other O&M billing lead days.

b. Staff’s Position

(i) Collections Lag

For Peoples Gas, the Commission should approve Staff’s proposal of 47.765 collections lag days and 64.935 revenue lag days. Staff Ex. 9.0 at 17. In direct testimony, Staff proposed adjustments to CWC for the Companies based on its calculation of CWC using the Gross Lag Approach, which is the same methodology used by the Companies. Staff Ex. 2.0 at 4. Staff’s adjustment reflects changes to the expense and revenue inputs into the CWC calculation as well as changes to the proposed lead days for pension expense for both Companies and the proposed collection lag proposed by Peoples Gas. Id.

Staff recommends that the intercompany billing lead of (30.56) be used for pension expense rather than the zero-expense lead proposed by the Companies because the Companies have an irregular timing of contributions to its pension plan. Id. The Commission has previously adopted Staff’s recommendation here that the pension
expense lead be based on the intercompany billing lead, rather than the zero-expense lead proposed by the Companies. *Id., citing* Docket Nos. 12-0511/0512 (cons.). Further the Commission’s Order in Docket Nos. 14-0224/14-0225 (cons.) approved the expense lead for pensions at the intercompany billing lead. In that proceeding, Peoples Gas and North Shore proposed that the pension expense lead be the intercompany billing lead and the issue was not further addressed by any party or the Commission. Docket Nos. 14-0224/14-0225 (cons.), Order at Attachs. A and B, at 9, col. (D), ins. 7, 9.

In this proceeding, Peoples Gas is proposing a 68.52 collection lag. Staff Ex. 2.0 at 5. In Docket Nos. 14-0224/14-0225 (cons.), the Company proposed, and the Commission approved, a total revenue lag of 46.16 days which included 29.31 days in collection lag resulting in a 39 day or 133% increase between proceedings. Docket Nos. 14-0224/14-0225 (cons.), Order at Appx. B at 9; PGL WP8.

Peoples Gas states that the 39-day increase is due to the change in methodologies due to information system changes as well outstanding various external factors. Staff Ex. 2.0 at 6 (*citing* PGL Ex. 10.0 REV at 4). While Staff does not dispute the increase in collection lag during the duration of the requirements set forth in Docket No. 20-0309, it is Staff’s opinion that the data used when calculating the collection lag in this proceeding is not representative of what should be forecasted for the 2024 test year. Staff Ex. 2.0 at 6. As stated in PGL Ex. 10.0 REV at 9, accounts receivable aging data for calendar year 2021 was used by Peoples Gas to calculate the collection lag in this proceeding. *Id.* at 6-7.

In response to a Staff data request, Peoples Gas conducted a collection lag based on 2022 actual data. In that study, the collection lag dropped from 68.52 days in the test year to 60.21 days based on the Company’s most recent calendar year data. *Id.* at 7. The Company does not believe that the collection lag study based on 2022 actual data is appropriate to use for the 2024 test year. While the Company claims the UDAP grants that were applied to ratepayer accounts skew the results of their 2022 collection lag study, Staff notes that the Company did not consider the fact that the requirements set forth in Docket No. 20-0309 were extended by the Commission until March 31, 2022, which may skew three months of collection lag to its favor. *Id.* at 7-8.

Due to the difficulty in using collection lag data from 2021 and 2022, Staff proposed a three-year average be used based on the amounts calculated within the study performed in Docket Nos. 14-0224/14-0225 (cons.), the study proposed by the Company in this proceeding, and the updated study requested. *Id.* at 8. Staff’s analysis shows that the Company’s proposal is far out of line with the most recent rate cases. *Id.* at 9. Also, while Staff’s proposed lag is greater than the average of Peoples Gas’ five previous rate cases, it does reflect an increase consistent with the Company’s studies, but a more reasonable increase in the lag. *Id.*

In rebuttal testimony, Staff noted that neither the Companies nor other parties objected to the mechanics of the computation; however, there is disagreement over the inputs for lead/lag days for: (a) collections and revenue, (b) intercompany billings, and (c) non-pass through taxes. Staff Ex. 9.0 at 6. In rebuttal testimony, Staff recommended 47.77 lag days for collections, which results in 64.94 revenue lag days. *Id.*
In addition to the external factors cited by the Companies, Peoples Gas discussed other actions that affected the collections and revenue lag since the last rate case, including implementing a new Customer Information System ("CIS") platform. The Company mentioned that as result of that change, cash collection data is no longer available. As such, accounts receivable aging data for 2021 ("new method") was used to calculate the collections lag in this proceeding. Staff Ex. 9.0 at 9.

The cash collections data is what was used as the basis of the collections lag in the last rate case and before the implementation of the new CIS platform in 2017. In the last rate case, the cash collections-based collections lag was 29.31 and the accounts-receivable aging-based collections lag was 69.87 immediately following the implementation of the CIS platform in 2018. Staff states that this change in the information used in the calculation collections lag used in the revenue lag may be the cause for the increased collections lag days, but the Company does not know the actual increase or decrease that may have occurred if it was based on the cash collections data. Accounts receivable aging data and cash collections data are not the same data, and therefore, the results they produce are not exactly the same if the variances are not properly accounted for. The change in the calculation of the collections lag based on cash collections to accounts receivable ageing data is similar to an accounting method change and they do not yield the same results. Staff Ex. 9.0 at 9-10.

Staff argues that Peoples Gas has not justified the proposed change. Id. Peoples Gas did not provide an analysis of any potential anomalies or disparities in the collections lag based on the cash collection and accounts receivable aging data or address the potential effect of the use of different data sources compared to the last rate case and how it accounted for them. Id. Peoples Gas did not explain why cash collection data is no longer available since the last rate case to justify the change data used for CWC collections lag calculation. Id.

The Company agreed with Staff’s averaging proposal as presented in Staff Exhibit 2.0, Schedule 2.01 P, but disagreed with the use of the 2012 data and stated, “Peoples Gas maintains that 2021 accurately predicts the collection lag for the 2024 test year, and that the inclusion of 2012 in both Mr. Alan’s and Mr. Gorman’s proposals is inherently flawed and was chosen as an arbitrary means to artificially decrease our collection lag.” Staff Ex. 9.0 at 14. In its response to Staffs’ proposal, the Company provided alternative information. Id. The historical collections information based on the new method provided by the Company starts in 2018 because data before 2017 does not exist anymore. Id. There is a gap of five years of missing information which is necessary to understand what happened since the last rate case. Id. As such, the historical information provided is not sufficient to demonstrate that the use of the 2021 information is reasonable, nor does it provide a reasonable explanation for the jump from 29.31 days of collection to 69.52 in 2021 compared to as filed 2013, let alone 68.52 collection days of 2018. Id. at 14-15. The Company’s argument in its Initial Brief that Staff is merely speculating that the missing data might help understand the increase in collections lag since the 2015 rate case should be given no weight. This argument only further proves Staff’s point that the information is necessary to determine what in fact happened since the last rate case.

It is Staff’s opinion that the additional information provided by the Company also contradicts the reasons provided for the increase in the collections and revenues lags
based on the changes in collections and payments habits due to the COVID-19 pandemic and the Commission's disconnection moratorium from Docket No. 20-0309. Staff Ex. 9.0 at 15. Based on the historical information provided by the Company, the increases started in 2018 before the COVID-19 pandemic and Commission disconnection moratorium. Id. Therefore, the Commission should reject the Company's proposal and adopt Staff's proposal. It is Staff's opinion that all the reasons the Company provided have not justified the reasonableness of the requested increase in the collections and revenue lags, thereby making information from the last rate case more reliable. Furthermore, the utility's inability to provide collection information from 2013-2017, before the new CIS and COVID19-response impacted collections activity, should not be permitted to have negative impacts on ratepayers by allowing the utility to base its collection lag amounts on inappropriately skewed and unrepresentative 2018-2021 collection lag amounts. Id. at 16.

Staff states that the Commission should also reject CUB/PCR/City witness Gorman's proposal. Mr. Gorman stated that using 2021 data results in an excessive collection lag estimate for 2024 because it was the year following the Commission's emergency order in Docket No. 20-0309 that directed the Company not to disconnect customers’ services due to the COVID-19 pandemic. CUB/PCR/City Ex. 1.0 at 7. Mr. Gorman concludes, “[t]his prohibition on disconnection and charging late fees results in 2021 revenue collection to be abnormal and not appropriate for measuring a utility’s CWC requirement.” Id. at 6. Mr. Gorman also observes that Peoples Gas did not provide evidence supporting the reasonableness of the use of the 2021 revenue collections to support its use in the calculation of the CWC for the 2024 test year and recommended that, “The lead-lag study from Peoples’ last rate case, based on 2012 collection data, although dated, represents a more reasonable normalized bill collection period than that developed from 2021 data.” Id. at 7.

Staff agrees in part with Mr. Gorman’s proposal. Staff Ex. 9.0 at 12. It is Staff's opinion the Company has not provided sufficient justification for the reasonableness of its revenue lag and collections proposal in its rebuttal testimony, and as filed based on 2021 data. Id. Staff agrees with Mr. Gorman's statement that the 2021 data and associated responses were too significantly affected by the COVID-19 pandemic to be a good representative of the 2024 test year. Id. at 12-13. However, Staff disagrees with Mr. Gorman’s proposal because it overlooks changes and updates that may have occurred since the last rate case. Id. at 13. Therefore, the Commission should adopt Staff's recommendations.

The Company disagreed with Mr. Gorman's proposal to use the collections information from Peoples Gas’ last rate case that was based on 2012 information. Id. The Company stated that the information from 2012 was too outdated and overlooked the effects of the COVID-19 pandemic. Id. However, in response to Mr. Gorman, Peoples Gas also said, “Peoples Gas’s 2021 collection lag was in line with historical amounts from 2018-2019 before we saw any effects from the COVID-19 pandemic.” Staff Ex. 9.0 at 13, citing NS-PGL Ex., 18.0 at 5-6. In Staff's opinion, this conflicts with the Company’s own assertion that part of the cause of the increase in the 2021 revenue and collections lag was based on the COVID-19 pandemic and associated responses. Staff Ex. 9.0 at 13. This is because the Company subsequently stated the collections immediately before the COVID-19 pandemic (2018-2019) were the same or close to that experienced in 2021 in
order to justify the use of the 2021 information in the calculation of the CWC. *Id.* The Company’s response to Mr. Gorman’s proposal is unpersuasive as the Company failed to demonstrate the justification for the increase in revenue and collection lags. *Id.* at 13-14.

Staff further states the Commission should disregard the Company’s argument that Staff’s proposed collection lag methodologies are “aimed at cherry-picking data to drive the collections lag lower, thus reducing cash working capital.” NS-PGL IB at 82. That is false. Staff asserts its proposal is based on the average of the last rate case information (2012) and also uses information from the Company’s rebuttal. *Id.* The 2012 information from the last rate case was more stable and normalized, and the current information from the Company’s rebuttal testimony includes the effects of the changes due to the passage of time, inflation, and other social and economic aspects. *Id.*

(ii) **Intercompany Billing Lead Days**

Staff agrees with Ms. Selvaggio’s proposal that the intercompany bills calculation be based on the end of the month payments to prevent rates from being inflated due to early payment since the WEC AIA states, “Each Receiving Party will pay outstanding balances by the end of the month.” The Commission should approve this proposal. Staff Ex. 9.0 at 18.

(iii) **Non-Pass-Through Taxes Billing Lead Days**

Staff agrees with Ms. Selvaggio’s proposal to recalculate the lead-days based on the due date for payments, rather than earlier payment dates used by the Companies, to prevent rates from being inflated due to early payment of taxes. The Companies do not have to pay their taxes earlier than they are due to be paid to avoid late fees and interest and early payment unnecessarily increases costs to ratepayers. Staff states the Commission should approve this proposal. *Id.* at 19.

(iv) **Other O&M Billing Lead Days**

AG witness Selvaggio provided a recommendation for an updated PGL calculation of its O&M lead days in rebuttal testimony. Ms. Selvaggio testified that an updated O&M lead calculation was required because many of the transactions she had analyzed were duplicates and thus, there was the possibility of errors in the payment processing lead times. She therefore recommended Peoples Gas include an updated O&M lead calculation in its rebuttal lead/lag proposal. Peoples Gas provided the update as NS-PGL Ex. 18.2. The updated calculation increases the O&M lead from 36.82 days to 38.40 days, which is reflected on Schedule 9.08 P. Staff agrees with Peoples Gas’ calculation. Staff considers this issue uncontested, and urges the Commission to approve the updated calculation. Staff Ex. 9.0 at 19-20.

c. **AG’s Position**

When assessing the Companies’ CWC calculations, AG witness Selvaggio found four areas that required adjustments: (1) intercompany-lead days; (2) non-pass-through taxes lead-days; (3) other O&M lead days (PGL only); and (4) changes in revenues and expenses and ROE to reflect the positions in the AG’s testimony. *Id.* at 7. The AG notes that PGL declined to address Ms. Selvaggio’s CWC calculation of changes in revenues and expenses and ROE. However, the AG takes issue with the Companies’
characterization of the AG’s position from North Shore and Peoples Gas’ consolidated 2018 Rider UEA reconciliation, in reference to CUB/PCR/City witness Gorman’s collection lag adjustment.

(i) Intercompany Billing Lead Days

The AG contends that the Commission should reject the Companies’ argument that it cannot review its timing of payments to its affiliates even where it drives up CWC costs to consumers, and that the Commission also reject the Companies’ red herring argument that distorts their flawed calculation of intercompany billing lead days. Ms. Selvaggio adjusted the Companies’ intercompany billing lead days to reflect payments to affiliates on the last business day of the month, consistent with the payment due date in the WEC AIA. AG Ex. 1.00 at 7. According to the WEC AIA, “Each Receiving Party will pay outstanding balances by the end of the month following the availability of detailed information about charges.” Id. In contrast, the AG notes that the Companies’ calculated their intercompany billing lead-days based on payments to affiliates before the end of the month. Id. The Companies’ calculation resulted in shorter lead-days for intercompany billings — at a higher CWC cost to ratepayers. Id. at 8. By deviating from the AIA and reducing intercompany billing lead-days, the AG asserts that the Companies effectively ask ratepayers to cross-subsidize their affiliates by paying affiliates earlier than other vendors. Id.

The Companies argue that they are entitled to calculate their intercompany billing lead days using any date before the end of the month. However, the AG maintains that the Companies do not pay non-affiliated vendors until the last day of the month, and it is unreasonable for them to pay affiliates sooner than non-affiliated vendors. According to Ms. Selvaggio, by paying affiliates earlier than other vendors, the Companies increase their CWC expenses and effectively ask ratepayers to cross-subsidize their affiliates. AG Ex. 1.00 at 7. The Companies argue that the AG’s contention is “unfounded” because NS/PGL witness Addison “identified an error in how Peoples Gas had calculated Other O&M billing lead, which, if corrected, would have been to the Companies’ favor; however, in order to simplify the issues in the case, the Companies did not pursue the correction. … As Mr. Addison explained in his surrebuttal testimony, the correct billing lead for Other O&M billing lead should have been 26.91 days for Peoples Gas and 33.11 days for North Shore—less than the intercompany billing lead, meaning that Ms. Selvaggio’s criticism of the relative speed of payments to affiliates and non-affiliates is unfounded.” NS/PGL IB at 87.

The AG points out that this argument ignores Ms. Selvaggio’s adjustment to Peoples Gas’ Other O&M billing lead days based on errors in PGL’s calculation of Other O&M. In reviewing the Companies’ CWC calculations, Ms. Selvaggio found that not only did PGL calculate its Other O&M billing lead days based on an incorrect date, but it also included duplicate transactions that the Company was required to remove in rebuttal testimony. As a result of these errors, Ms. Selvaggio recommended that PGL’s Other O&M billing lead days be set to 43.17 days, the same number of days as North Shore. According to the AG, the Companies here distort their flawed calculation of intercompany billing lead days by comparing it to a hypothetical and equally flawed calculation Other O&M lead days (which the Companies declined to adopt).
The AG asks the Commission to reject this red-herring argument and require the Companies to set intercompany lead days to the last day of the month. The AG requests the Commission increase the Companies’ intercompany billing lead-days to 45.40 days for North Shore (compared to NS’s proposed 30.77 weighted lead days) and 45.54 days for PGL (compared to PGL’s proposed 30.56 weighted lead days), as shown in the AG Initial Brief, Attach, NS & PGL, Sch. 8 at 1, Ln. 10, Col. (d).

(ii) Non-Pass-Through Taxes Billing Lead Days

The AG argues that nothing in the record indicates that NS-PGL have inadequate resources to manage their tax payments on the day those payments are due. The AG urges the Commission to adjust PGL and North Shore’s non-pass-through taxes billing lead days to reflect payment of taxes on their due date, rather than on an earlier date as proposed by the Companies. *Id.* Ms. Selvaggio adjusted the Companies’ non-pass-through taxes billing lead-days to reflect payment of taxes on their due date, rather than on an earlier date as proposed by the Companies. AG Ex. 1.00 at 10. The Companies calculated their CWC based on the payment of taxes earlier than is required by law, thus increasing CWC costs to ratepayers. *Id.*

The Companies argue that the Commission should reject the AG’s adjustments because the Companies pay taxes early to avoid missed payments and to mitigate unnecessary disputes regarding their tax payments. However, the AG contends that PGL and NS are large companies with $1.1 billion and $112 million proposed revenue requirements, respectively. According to the AG, there is no evidence in the record to indicate either utility has inadequate resources to manage their tax payments on the day those payments are due.

The AG asserts that ratepayers should not be required to pay inflated CWC expenses based on the Companies’ unfounded fears that they will miss their tax payments if those payments are scheduled on the due date. The AG notes that the Commission has previously held that lead-days for taxes should be based on the date those taxes are due to “protect ratepayers from incrementally higher rates attributable to the utility’s practice of remitting taxes earlier than they are due.” *Ameren Ill. Co. d/b/a Ameren Ill.*, Docket No. 13-0192, Order at 19 (Dec 18, 2013). The AG believes the Commission should reach the same conclusion here and adopt Ms. Selvaggio’s proposed non-pass-through taxes billing lead days as shown on AG Initial Brief, Attach., Sch. 8, at 1, Lns. 18, 19, 20 and 23, Col. (d); AG Ex. 5.00 at 21.

(iii) Other O&M Lead Days

The AG argues that the Commission should not rely on PGL’s admittedly flawed calculation; it should instead require PGL use the same O&M lead days as North Shore. The AG recommends the Commission increase Peoples Gas’ other O&M lead days from 36.82 to 43.17 to remove duplicate transactions and other errors from PGL’s calculation. Ms. Selvaggio increased Peoples Gas’ other O&M lead days from 36.82 to 43.17 (North Shore’s proposed other O&M lead days) based on her discovery of duplicate transactions and other possible errors within PGL’s calculation. AG Ex. 1.00 at 12.

In response, PGL complains that the AG “provided no evidence” to support its calculation. NS/PGL IB at 89. PGL witness Addison acknowledged that the Peoples Gas'
CWC was improperly based on the “Date Entered” rather than the “Invoice Date,” but he declined to change his calculation to correct this error. NS-PGL Ex. 18.0 at 11–12. Between the duplicate transactions and the improper dates that formed the basis of PGL’s calculation, the AG maintains that the Commission should require PGL use the same O&M lead days as North Shore, rather than rely on the PGL’s admittedly flawed calculation. The AG avers that it is a logical use of an affiliate’s lead days when PGL’s own calculation is patently flawed. North Shore’s other O&M lead days is uncontested and as affiliates NS and PGL should have similar payment practices.

For these reasons, the AG recommends the Commission require PGL to use 43.17 lead-days in its CWC calculation of other O&M. This adjustment is reflected on AG Initial Brief, Attach., PGL, Sch. 8 at1, Ln. 16, Col. (d).

The AG asks the Commission to adopt Ms. Selvaggio’s CWC calculations as shown on AG Initial Brief, Attach., NS & PGL, Sch. 8.

d. CUB/PCR/City’s Position

   (i) Collections Lag

CUB/PCR/City request that the Commission adopt Mr. Gorman’s recommendation to remove from rate base what CUB/PCR/City consider to be the excess portion of PGL’s proposed $131 million CWC. CUB/PCR/City attribute this excess to PGL overstating its collection lag. CUB/PCR/Chicago Ex. 1.0 at 4-9. CWC represents the amount of reserve funds a utility must keep on hand to cover day-to-day operations. See PGL Ex. 10.0 at 3. Revenue lag represents the time between when the utility renders service and when the utility receives payment from its customers. Id. at 4. The longer the revenue lag, the more CWC the utility needs to maintain. Id. The four components of PGL’s revenue lag are service lag (average time from when service is rendered to when meter is read, i.e., half a month), billing lag (between meter reading and bills going out, i.e., roughly one day), collection lag (between bills going out and the utility’s receipt of payment), and bank float (from depositing funds in the bank to those funds becoming available to PGL). See id. at 4, 6-7.

CUB/PCR/City urge the Commission to reject PGL’s proposed collection lag, arguing it unreasonably inflates CWC according to outdated assumptions. PGL bases its requested CWC on a collection lag derived from accounts receivable aging data for calendar year 2021. CUB/PCR/City Ex. 1.0 at 5. Using this data would result in an 86% increase in collection lag, from 46.16 days to 85.69 days. Id. at 4. CUB/PCR/City contend a collection lag of nearly 3 months is grossly out of step with the norm and cannot be considered a reasonable baseline for Test Year expectations. CUB/PCR/City witness Gorman attributed this increase since PGL’s last rate case to two factors: (1) the COVID-19 pandemic and resulting emergency shutoffs moratorium, which were temporary and have since passed, and (2) PGL collection practices that the Commission recently found to be imprudent and unreasonable and ordered PGL to reform. Id. at 5-6; CUB/PCR/City Ex. 3.0 at 6-8.

Regarding the pandemic, Mr. Gorman explained that 2021 was the year after the Commission initiated its emergency order in Docket No. 20-0309 that directed PGL not
to disconnect residential customers’ service or impose late payment fees for nonpayment, and this order remained in effect for much of the year. CUB/PCR/City Ex. 1.0 at 5-6.

In response, PGL witness Addison offered that PGL’s annual collection lag ranged from 60.2 to 70.8 days from 2018 to 2022, which included two full years preceding the COVID-19 pandemic. PGL Ex. 18.0 at 5. PGL’s authorized collection lag, which has been in place since its 2014 rate case, is approximately 29.31 days, less than half the lowest collection lag PGL experienced in the last 5 years. CUB/PCR/City Ex. 3.0 at 5. CUB/PCR/City posit that, all else being equal, this data trend would support PGL’s assumption that its CWC should be updated to incorporate a new reality whereby PGL has a historically lengthy collection lag. However, CUB/PCR/City do not consider all else to be equal. CUB/PCR/City maintain that PGL’s Commission-approved tariffs do not support such a conclusion, and a recent Commission order found that this increase in collection lag owes to PGL’s own imprudent and unreasonable collection practices. Id. at 5-8.

Thus, CUB/PCR/City offer, it is Peoples Gas’ own Commission-approved policy that customers are expected to remit payment to PGL within no more than 31 days after PGL issues their bills. See id. PGL’s current Commission-approved CWC assumes a collection lag of 29.31 days, which is compliant with PGL’s net payment period policy. CUB/PCR/City Ex. 3.0 at 5-6. Yet PGL now seeks Commission approval of CWC that assumes a collection lag of nearly triple that length, claiming that the shortest collection lag PGL has experienced in the last 5 years was still nearly double what its own net payment period policy allows.

CUB/PCR/City allow that PGL’s request would be reasonable if it had been taking all reasonable measures to collect past due payments and nonetheless the collection lag swelled due to factors outside of the utility’s control. However, CUB/PCR/City argue the Commission found in no uncertain terms that this was not the case in a recent order. In PGL’s most recently decided uncollectibles rider reconciliation, the Commission investigated the propriety of PGL’s collection practices. See generally Docket Nos. 20-0665/20-0666 (cons.), Order (May 18, 2023). In that proceeding, the Commission noted that Peoples Gas must manage its uncollectible cost responsibility through implementation of tariff mechanisms and pursue minimization of written-off uncollectible arrears in all collection activities enumerated in Section 19-145(c) of the Act, while also adhering to all Commission rules. Id. at 2. Specifically, the Commission found that the Companies should identify customers with late payments, contact them in an effort to obtain payment, inform them of payment assistance options, and pursue collection activities and implement disconnections based on the level of uncollectibles. Id. at 3. The Commission found PGL did not act prudently or reasonably in furtherance of Section 19-145(c) during the reconciliation period (2017). Id. at 21. Based on these findings, the Commission ordered PGL to refund customers over $15.4 million in excess uncollectibles. Id. at 20-23.

To normalize collection lag to be more representative of ordinary circumstances and reasonable and prudent utility collection practices, CUB/PCR/City argue the Commission should adopt Mr. Gorman’s recommendation to keep in place the currently-authorized collection lag component of PGL’s CWC. CUB/PCR/City Ex. 1.0 at 8-9. CUB/PCR/City contend that, unlike PGL’s requested amount, the current Commission-
approved collection lag of 29.31 days complies with PGL’s net payment period tariff policy and reflects both (a) circumstances preceding the pandemic; and (b) PGL collection practices preceding those the Commission has found to be imprudent and unreasonable. This adjustment reduces PGL’s revenue deficiency by approximately $10.3 million. Id. at 9.

If the Commission declines to adopt CUB/PCR/City witness Gorman’s recommended adjustment to keep the Companies’ current approved collection lag in place, CUB/PCR/City support the adoption of Staff witness Alan’s averaging approach in the alternative. See Staff Ex. 2.0 at 6-7. CUB/PCR/City consider Mr. Gorman’s proposal more reasonable, as it is the only proposal in this proceeding which avoids the pitfall of including data altered by the pandemic and shutoffs moratorium (2021) and the downstream results of collections practices the Commission previously found to be imprudent (2021 and 2022). CUB/PCR/City also note Mr. Gorman’s approach is the only proposal in the docket that complies with the Companies’ own Net Payment Period policies. That said, CUB/PCR/City contend averaging unrepresentative data with representative data is still better than relying entirely on outlier data, as the Companies propose.

CUB/PCR/City also support AG witness Selvaggio’s separate adjustments to CWC. See AG Ex. 1.0 at 6-12. The revenue impact of these adjustments for PGL and NSG are approximately $820,000 and $67,000, respectively. AG Ex. 1.01 PGL, Sch. 5; AG Ex. 1.01 NS, Sch. 5.

e. Commission Analysis and Conclusion

While it is common practice for the Commission to use the most recent data when establishing rates, that data must be reliable. Here the collections lag data from the Companies lead/lag study is unreliable due to the effects of the COVID-19 pandemic and the Commission’s moratorium on disconnections. CUB/PCR/City recommend leaving the currently authorized collection lag in place. Staff offers an alternative approach by combining the currently authorized collections lag representing the last known reliable data with a current 3-year average. The increase in the collections lag since the Company’s last rate case may be the result of the pandemic but it also could be the result of other factors and more likely, a combination of both. Staff’s approach acknowledges this fact, and the Commission finds it to be a reasonable solution and is hereby adopted. The Commission approves a collection lag of 47.77 days.

As the Companies point out, the AIA allows the Companies to pay outstanding balances by the end of the month following transactions. While the Companies may choose to pay their outstanding balances early, the customers should not be forced to pay extra for that decision. The Commission reaffirms its position on this issue made in the Companies’ last rate case in Docket No. 14-0224/14-0225 (cons.).

It is the Commission’s position that CWC and rate base should not be increased when utilities pay expenses earlier than necessary.
Docket No. 14-0224/14-0225 (cons.), Order at 40. The Commission accepts the intercompany billing lead days of 45.40 for North Shore and 45.54 for PGL as calculated by the AG and supported by Staff.

Similar to intercompany billing lead days, the Commission finds no reason to reward utilities and penalize customers when a utility chooses to pay non-pass-through taxes earlier than necessary. The Companies are free to make payments in advance of due dates but the choice to do so should not be reflected in the calculation of CWC. The Commission accepts the following non-pass-through tax lead days as calculated by the AG and supported by Staff:

<table>
<thead>
<tr>
<th></th>
<th>North Shore</th>
<th>PGL</th>
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<tbody>
<tr>
<td>Federal Unemployment</td>
<td>77.13</td>
<td>77.13</td>
</tr>
<tr>
<td>State Unemployment</td>
<td>77.13</td>
<td>77.13</td>
</tr>
<tr>
<td>Real Estate</td>
<td>389.55</td>
<td>382.73</td>
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<tr>
<td>Sales &amp; Use</td>
<td>31.36</td>
<td>(2.70)</td>
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</table>

The Commission declines to adopt the AG’s recommendation to use North Shore’s Other O&M billing lead days of 43.17 for Peoples Gas. In rebuttal testimony, the Companies provided an updated calculation of lead days for Peoples Gas’ Other O&M at the request of the AG. The update corrected the errors identified by the AG and no additional errors to the calculation were identified. The Commission approves the Other O&M lead days of 43.17 for North Shore and 38.40 for Peoples Gas.

5. Other Issues
a. SMP Project Management
Section IV.B.1.e. above.

b. Policy Proposals Related to the Clean Energy Transition
(i) Companies’ Position

The Companies contend that several intervenors seek to use this rate case to do much more than challenge the justness and reasonableness of the Companies’ forecasted revenue requirements and proposed rates for 2024. They would convert this rate review proceeding into a broad investigation that would examine a variety of policy proposals and initiatives related to decarbonization and the so-called “future of gas.” Those policy proposals range from the general to the highly specific, and include certain proposals—some contradicting others—that either are not supported by or, in some cases, are contradicted by, current Illinois law. NS-PGL Ex. 12.0 REV at 12.

Most of those intervenor proposals have little or nothing to do with the Companies’ test year rates. These proposals aim instead at bringing about an abrupt change in the natural gas industry, and, even more broadly, in the overall energy production and delivery model in the United States. The Companies note that the proposals range from requiring CPCN for gas pipeline projects that exceed certain monetary thresholds; to capping such projects at different cost-per-mile levels for Peoples Gas and North Shore; to requiring various integrated resource plans for infrastructure work; to slowing the pace.
of the SMP; to changing or eliminating line extension allowances; to conducting NPAs for major pipeline projects; to adopting performance-based ratemaking ("PBR") for gas utilities; and others. NS-PGL Ex. 12.0 REV at 8–11.

Peoples Gas and North Shore assert that these proposals, none of which have garnered support from Staff, “are all based, to varying degrees, on speculative and uncertain predictions about the pace and feasibility of decarbonization and electrification efforts in Illinois and are, as a result, premature.” NS-PGL Ex. 23.0 at 16, 17. Moreover, many of the proposals would make it “much more difficult, costly, and dramatically slower, if not impossible, for Peoples Gas to continue the critical work of modernizing Chicago’s gas infrastructure to improve its reliability and safety,” even though multiple Commission proceedings and Commission-sponsored engineering studies have highlighted the need to perform such work on an accelerated basis. NS-PGL Ex. 12.0 REV at 8.

(a) Performance-Based Ratemaking

The Companies state that proposals for PBR should be rejected. The PBR proposals offered by certain intervenors are plainly contrary to applicable Illinois law and lack justification in the evidentiary record.

As a threshold matter, the default model of ratemaking in Illinois is plainly not based on a PBR approach. Rather, “the core of the Act” is the traditional “rate-of-return principle[].” People ex rel. Madigan v. Ill. Commerce Comm’n, 2015 IL 116005, ¶ 29. That model “factor[s] both a recovery of prudent and reasonable costs and a return on equity into the equation used to determine the revenue requirement.” Id. at ¶ 30. Obviously, any exception to that approach must be grounded in a clear exception to the Act’s reliance on the rate-of-return principle. However, no intervenor identifies a valid statutory exception or other authority to justify the use of PBR in this case.

That is not surprising, as no applicable exception exists according to the Companies. Notably, the main witness proposing PBR—PIO witness Cebulko—dedicates approximately 25 pages of written testimony to PBR issues, yet provides no citation to the Act or any other substantive legal authority to support his PBR proposals. PIO Ex. 1.0 at 80–102; PIO Ex. 4.0 at 39–43. To be clear, the Act contains a carefully constrained exception for a PBR approach in limited circumstances under Section 9-244, which specifically requires that any proposed PBR proposal be initiated upon a “petition by an electric or gas public utility.” 220 ILCS 5/9-244(a). Thus, the Companies state it would have been plainly contrary to the statutory text for Mr. Cebulko to try to defend PIOs’ proposal under Section 9-244. Section 9-244’s language conveys without doubt the legislature’s express intent that the exceptional circumstance of a PBR proposal is statutorily permitted only if proposed by the utility. People ex rel. Sherman v. Cryns, 203 Ill. 2d 264, 286 (2003) ("[T]he enumeration of exceptions in a statute is construed as an exclusion of all other exceptions" under the principle of expressio unius est exclusio alterius").

Further, the Companies state, the latest legislative developments in Illinois leave no doubt that PBR is not appropriate for gas utilities. “[W]hile [P.A. 102-0662] ushered in a performance-based ratemaking scheme for electric utilities, it did not do so for gas utilities.” NS-PGL Ex. 12.0 REV at 14. That fact, taken together with the absolute lack of any other provision in Illinois statutes or regulations requiring a gas utility PBR approach,
leaves no doubt that the PBR proposals in this case are legally invalid. *Id.* at 14. In short, “[t]he Act governs the Commission…” *People ex rel. Madigan*, 2015 IL 116005 at ¶ 19. The Commission may not deviate from the Act simply to accommodate policy preferences of an intervenor or its witness, particularly where the statutory structure leaves no doubt that PBR cannot be imposed on gas utilities.

Regardless of its legality, the Companies argue the evidence fails to justify the PIO proposal. Ms. Eldringhoff testified about the complexity of the dozens of categories of performance metrics suggested by Mr. Cebulko. NS-PGL Ex. 14.0 REV at 37. She noted that they are both “redundant” to various other extensive reporting obligations that the Companies already have, and “unnecessary.” *Id.* at 37–42. The existing reporting obligations that Ms. Eldringhoff detailed demonstrate that the Commission already has access to significant amounts of information. Expanding those obligations in this utility-specific rate case in service of a vague PBR proposal that has no basis in Illinois law would be burdensome and useless.

Lastly, it is not clear from PIOs’ initial brief whether it is continuing to specifically advocate for the imposition of PBR in this rate case. The Companies state that PIO now seems to refer to the theoretical value of PBR without affirmatively advocating for PBR to be implemented in this proceeding. PIO IB at 48–50.

(b) Gas System Planning

(i) Future of Gas Proceeding

Industry-wide issues relating to decarbonization and the “future of gas” merit careful and deliberate study, and the Companies stand ready to participate with the numerous other stakeholders who will need to play a role in that process. *Id.* at 16. The Companies assert that the necessary examination of the “future” to make informed and prudent decisions is complex.

It is the Companies’ position that any study of decarbonization and/or future of gas, should the Commission undertake it, ought to occur not in a utility-specific rate case that is statutorily confined to an 11-month timeframe, but instead in a separate, methodical, deliberative, and carefully designed statewide process where all relevant stakeholders and subject-matter experts—including some who almost certainly are not part of this rate case—have an opportunity to participate. The Companies explain that this process will also afford the requisite evaluation and understanding of what can be accomplished in certain time frames and at what cost with respect to electrification. Relatedly, it should provide an opportunity to study the separate questions of (1) what the future of natural gas will be during these time frames, and (2) how the pipeline system currently used to distribute natural gas could be repurposed to support decarbonization through the use of low- or non-carbon fuels. This utility-specific rate case, however, is neither the time nor the place to evaluate—let alone implement—the intervenors’ policy proposals. NS-PGL IB at 97; NS-PGL RB at 38–39.

The Companies argue that if the Commission were inclined to consider any of these proposals, the proper place to do so would be in a generic proceeding or workshop docket where decisions could be made based on a common record and with a full view of all of the intended and unintended consequences, consideration of externalities, and
input from all relevant stakeholders. NS-PGL Ex. 12.0 at 15-16. Making such consequential decisions in a piecemeal fashion in four separate gas utility rate cases, under tremendous time and resource pressure, is likely to lead to inconsistent results.

Accordingly, the Companies contend that it would be much better for the Commission to hold a Future of Gas proceeding as the intervenors suggest to address these issues, which could result in rulemaking or statutory changes that would support and properly define, with a fulsome and dedicated record, the policy proposals that the intervenors are advancing in North Shore’s, Peoples Gas’, Ameren’s, and Nicor’s rate case proceedings. *Id.*

(ii) Infrastructure Plans

The Companies state proposals for Integrated Resource Planning (“IRP”) for gas utilities should be rejected. As with the other policy proposals offered by various intervenors, the IRP proposals are plainly contrary to applicable Illinois law and lack justification in the evidentiary record.

IRPs used to be required under Illinois law for both electric and gas utilities. NS-PGL Ex. 12.0 REV at 13, *citing* 111 ILCS § 8-402 (1988). However, Illinois law was amended over 25 years ago to eliminate that requirement for gas utilities. NS-PGL Ex. 12.0 REV at 13, *citing* 111 ILCS § 8-402 (1997). Thus, the Companies state there is no existing statutory basis for gas utility IRPs.

P.A. 102-0662, which was recently passed, eliminates any doubt on this point. The Companies point out that P.A. 102-0662 “contains extensive integrated grid planning requirements for electric utilities[,]” including many of the elements the intervenors advocate for in this case. NS-PGL Ex. 12.0 REV at 13, *citing* 5 ILCS 5/16-105.17 *et seq.* P.A. 102-0662 imposed no similar IRP requirements on gas utilities. Thus, there is absolutely “no statutory basis for requiring gas utilities to prepare” IRPs. NS-PGL Ex. 12.0 REV at 13. To the contrary, “the statutory history supports the opposite conclusion that the legislature has decided that there should not be integrated resource planning for gas utilities.” *Id.*

In addition to the legal invalidity of the IRP proposals, Ms. Eldringhoff testified about the practical problems with those proposals:

Subjecting the utilities to integrated resource planning requirements would likely have the unintended consequences of cost increases and project delays. As I have previously stated, proposing continuous (or at least annual) material changes to program management of a multi-decade and multi-phase project is a poor way to pursue a project aimed at increasing safety and reliability and goes against the basic [tenets] of project governance.

NS-PGL Ex. 14.0 REV at 49.

(c) Non-Pipeline Alternative Analyses for Major Pipeline Projects

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The Companies urge the Commission to reject the proposals to require the Companies to implement Non-Pipeline Alternatives ("NPAs") to major pipeline projects. Again, as with the other policy proposals offered by various intervenors, the NPA proposals are contrary to applicable Illinois law, and lack justification in the evidentiary record.

The Companies state that PIO proposes implementation of an "NPA assessment framework that requires utilities to conduct NPA analysis for all major pipeline projects in its integrated infrastructure plan." PIO Ex. 1.0 at 41, 72–73. PIO provides no legal authority for requiring NPAs or IRPs. For the reasons stated in the immediately preceding section regarding IRPs, the Companies maintain that there is no statutory authority to require gas utilities to implement NPAs. Thus, there is no statutory authority for the PIO proposal to include NPAs in an IRP.

Other intervenors’ proposals similarly lack legal authority. For example, City witness Deleon suggests that Peoples Gas should perform NPAs “for all of its major capital projects.” COC Ex. 1.0 at 33. Neither there nor in any other part of her testimony does she explain the legal basis for requiring NPAs. That is unsurprising, because neither the Act nor the Commission’s regulations require NPAs.

The Companies argue that in addition to a lack of legal authority to require NPAs, the evidentiary record fails to demonstrate a persuasive reason to impose an NPA requirement. Mr. Graves explained that various NPA technologies “have their relative advantages and disadvantages for helping to reduce gas costs and potentially to help achieve broad decarbonization.” NS-PGL Ex. 33.0 at 12. In fact, NPAs “are not likely, on their own, to eliminate a great deal of gas demand or the need for local gas infrastructure.” Id. at 15. Further, Mr. Graves indicated that he is unaware of any state where “there is a commission finding about the extent to which NPAs can substitute for pipeline safety and leakage reduction expenditures.” Id. Nor was he aware “of any future of gas proceeding in which a schedule, framework, or architecture of shutting down segments of a distribution system as gas demand declines has been identified.” Id. Mr. Graves also highlighted some of the challenges of NPAs, perhaps most notably the need for “unanimous consent of all affected customers” absent which “the distribution main has to be maintained.” Id. Indeed, Mr. Graves points to multiple state efforts to implement NPA initiatives where the “unanimous consent” problem turned out to be a major impediment. See id. at 17.

The Companies add that Mr. Graves provided an extensive review of different classes of potential NPAs, and highlighted a variety of challenges, including difficulties with customer engagement, limited impacts even where NPAs are implemented, “snap-back effects” where customers actually increase gas usage prior to and after curtailment hours, the challenges of “gaining large customer enrollment and execution,” limited customer adoption rates, the need for “extremely high [customer] participation” for effectiveness, and the high cost of some NPAs. Id. at 18–21.

Notably, as NPAs might relate to the SMP, Mr. Graves stated: “While gas [demand response] and [energy efficiency] can be helpful tools for decarbonization, they alone will not eliminate the need for SMP-like investments. [Energy efficiency] is mostly going to help avoid upstream capacity and gas supply contracting at the system wide level, rather
than the need for local infrastructure.” *Id.* at 19. Mr. Graves concluded that NPAs “are certainly not a ‘silver-bullet’ to eliminate the need for SMP-like investments.” *Id.* at 21.

In the face of this evidence, the Companies state the intervenors take two basic approaches in briefing. First, they try to “soften” the impact of the proposal (this, and others) by characterizing it as “a ‘no-regrets’ approach.” *PIO IB* at 39, 42. The exact meaning of “no-regrets” in this context is somewhat opaque. It appears that *PIO* is suggesting that there is no downside to such a proposal, and therefore it is legally justified. *Id.* at 42 (referring to an NPA as “a ‘no-regrets’ step, because carrying out the analysis does not, in and of itself, require the Company to retire or to add any investments”). However, the Companies note that neither *PIO* nor any other intervenor points to any legal authority to support a decision-making process based on a “no-regrets” approach, however defined. *Again, this is unsurprising, as, to the Companies’ knowledge, “no-regrets” (again, however defined) is not a legal standard endorsed by Illinois law relating to utility regulation.* *NS-PGL RB* at 44–45.

Second, *PIO* suggests that an NPA protocol is justified in Illinois because “other states are already exploring, evaluating, and implementing NPAs.” *PIO IB* at 41. The Companies respond that even assuming that is true, such action in a few other states is a far cry from a legal justification—based on the current evidentiary record and in light of any clear Illinois legal basis—to institute a mandate for NPAs. *NS-PGL RB* at 45.

### (d) CPCNs for Gas Pipeline Projects and Cost-per-Mile Caps on Distribution Main Replacements

The Companies argue the AG’s proposal to require the Companies to obtain CPCNs for gas pipeline projects meeting some cost threshold and certain other intervenors’ proposals to impose cost-per-mile caps on distribution main replacements should be rejected. Once again, as with the other policy proposals offered by various intervenors, the CPCN proposals and cost cap proposals are contrary to applicable Illinois law and lack justification in the evidentiary record.

The Act, the Companies note, contains specific provisions about when a CPCN is and is not required. For example, Section 8-406 sets forth CPCN requirements, but specifically provides that a CPCN for gas distribution is not required when the gas distribution project is in “substitution of any existing plant, equipment, property or facility.” 220 ILCS 5/8-406(b). As Mr. Eidukas pointed out, “the entire point of Peoples Gas’s SMP is to replace aging, at-risk gas pipe.” *NS-PGL Ex. 12.0 REV* at 12; see also *NS-PGL Ex. 14.0 REV* at 51. Thus, a new requirement for a CPCN based on a cost threshold, as proposed by the AG, is directly contradicted by the plain language of the Act.

Similarly, the Companies contend the intervenors fail to provide any legal basis for a flat cost-per-mile cap on distribution main replacement. The touchstone of utility cost recovery under the Act is justness and reasonableness of costs incurred. 220 ILCS 5/9-101. The Companies state that the Act does not impose across-the-board cost caps for an obvious reason: utility infrastructure work can have highly variable cost depending on location, project complexity, underlying conditions (known and unknown), and other factors. Rather, it is the duty of the Commission to determine if an investment was “prudently incurred.” 220 ILCS 5/9-211. Like the proposal to require CPCNs, had the
legislature intended to impose a cost-per-mile cap on distribution main replacement, the Act would make that explicit, and no such provision exists.

The Companies assert that aside from the lack of any legal basis for CPCNs based on a cost threshold or cost-per-mile caps, both proposals would be highly detrimental to Peoples Gas’ effort to make the gas delivery system in Chicago safer. Ms. Eldringhoff explained that mandatory CPCNs that are not required by the Act would cause unnecessary delays and halt the ability to execute SMP efforts for all practical purposes, given that the process for obtaining a CPCN “can be lengthy and complex” and is not subject to a statutory deadline. NS-PGL Ex. 14.0 REV at 51. Regarding the timing, she noted that the Act provides for an expedited CPCN process for certain electric utility matters, but has no similar expedited process for gas utilities. Id. at 51.

Ms. Eldringhoff noted the similar problems with cost-per-mile caps, which “could significantly limit Peoples Gas’ ability to replace aging, at-risk pipe in a timely and effective manner, which can negatively impact the overall safety and reliability of the gas system.” NS-PGL Ex. 25.0 at 25. The Companies point out that she noted that delays could be particularly problematic in service areas “like Peoples Gas’s with high concentrations of older pipes that are more prone to leaks and other safety issues.” Id. at 25. Ms. Eldringhoff also highlighted the irony that a cost cap, while perhaps intended to contain costs, “could actually result in higher rates for customers in the long run as the utility would be forced to make more frequent, costly repairs.” Id. at 25–26.

(ii) AG’s Position

The AG argues that its recommendations—which seek to rein in the Companies’ unjustified spending, identify leaks and other known risks associated with investments, improve transparency, and enhance scrutiny of the Companies’ investment decisions consistent with the Act and the state’s energy laws and decarbonization goals—are plainly within the Commission’s ratemaking and regulatory powers. The AG requests that the Commission adopt its recommendations in full, including additional recommendations set forth in Rate Base in Section IV.B.1.f. of this Order.

The Companies complain that the AG’s recommendations are “policy disagreements” that should be addressed outside this proceeding, and generically contend that there is a “lack of legal basis” for the Commission to adopt the AG’s recommendations. See NS/PGL IB at 89, 95, 104, 105. The AG finds the Companies’ arguments unpersuasive.

The AG contends its proposals are not general policy disagreements, and that the record shows them to be directly derived from, and a result of, their witnesses’ data-driven analyses of the Companies’ plant investments and integrity management practices. For example, the AG asserts that its proposals to apply a per mile cap on cost recovery for the Companies’ distribution mains are based upon an analysis of historic spending and review of peer utilities. According to the AG, the Companies’ argument that the AG’s recommendations are in any way divorced from the facts presented in this docket are untenable.
(a) CPCNs for Gas Pipeline Projects and Cost-per-Mile Caps on Distribution Main Replacements

To enhance accountability and better align both Companies’ capital projects with the state’s energy laws and decarbonization goals, the AG asks the Commission to require the Companies to file plans for planned and completed projects, adopt a distribution per-mile cost cap of $1.3 million for NS and $7.2 million for PGL, and obtain a CPCN for new natural gas lines or non-reliability related natural gas infrastructure projects and/or programs that exceed $12 million. The AG avers that its requirements are data-driven, flexible, reasonable, and most importantly, necessary to monitor, mitigate, and actively address the dangers of costly stranded assets and issues of affordability as the state and its residents pursue an equitable, affordable path to a clean energy future.

AG witness Dismukes recommends the Companies be required to seek a CPCN for major, new natural gas lines or non-reliability related natural gas infrastructure projects that exceed $12 million and that “do not address the most critical system needs (i.e., Grade 1 and Grade 2 leaks).” AG Ex. 2.00 at 27. Given the state’s commitment to decarbonization, the AG believes the Commission should review any such costly major projects from the Companies that would expand its natural gas infrastructure in potential conflict of the state’s goals. The AG asserts that Dr. Dismuke’s recommendation would enhance the Commission’s visibility into these types of capital spending by the Companies, and give opportunities for the Commission and stakeholders to intercede and challenge projects inconsistent with best practices and public policies. AG Ex. 2.00 at 29. The AG requests the Commission adopt the CPCN recommendation, along with their recommended planning and reporting requirements, to promote transparency and to aid the Commission in identifying and reviewing costly projects.

The AG requests that the Commission require the Companies to provide, at minimum:

- Analysis of pipeline and non-pipeline alternatives to the chosen investment;
- Expected service life of installed pipeline facilities;
- All considerations undertaken by the Company of the risks posed by stranded assets associated with installed facilities; and
- Full analysis of the costs and benefits of the proposed investment, including how these compare to alternative investments considered by the Company.

The AG recommends the Commission adopt a CPCN filing requirement for any NS or PGL proposal that seeks new natural gas lines or non-reliability related natural gas infrastructure projects and/or programs that are estimated to cost $12 million or more.

(iii) City’s Position

The City asks the Commission to also address PGL’s failure to sufficiently plan for a sustainable, equitable, and decarbonized energy future. The City notes that this rate case is the first time that PGL has come before the Commission since the Illinois Legislature passed P.A. 102-0662 and the City issued its Climate Action Plan. The City
asserts that both of these key actions set ambitious targets relating to decarbonization, energy efficiency, energy equity and justice, and transitioning away from fossil fuels. The City points out that PGL has faced questioning in this case from the Commission, the City, and other parties regarding how PGL has planned for a decarbonized future (see Commissioners’ Question No. 4; COC Exs. 1.04, 1.05, 1.06, 1.07, 1.09, 1.10), and argues that PGL has failed to demonstrate that it has thoroughly considered its own role in the clean energy transition. The City adds that PGL has instead detailed the perceived challenges, speculated on how its infrastructure might continue be useful, appeared to attempt to undermine electrification, and, ultimately, indicated that it is proceeding with business as usual. See PGL Response to Commissioners’ Question No. 4; COC Exs. 1.04, 1.05, 1.06, 1.07, 1.09, 1.10.

According to the City, failing to plan, ignoring the State and City decarbonization targets, and continuing to heavily invest in gas infrastructure without due regard for affordability and stranded assets is an unacceptable response to an inevitable energy transition. The City adds that the Commission has the opportunity and obligation in this proceeding to address this disconnect by carefully scrutinizing capital investments, requiring NPAs and GHG emission analyses going forward, reevaluating the SMP, and opening a Future of Gas proceeding. The City states it is particularly concerned that PGL never meaningfully responded to some of its requests, including for a GHG emissions analysis, which is an important first steps to addressing the energy transition. City RB at 7, 13, 14.

(a) Gas System Planning

The City urges the Commission to consider the recommendations of PIO witness Cebulko regarding enhanced gas system planning. The City asks that the Commission take action in this proceeding to address enhanced infrastructure reporting for PGL specifically. The City supports the recommendations of Mr. Cebulko regarding gas system planning. See PIO Ex. 4.0 at 54-55.

(i) Future of Gas Proceeding

The City points out that PGL, and multiple intervenors in this case, have recognized that the Commission should open a Future of Gas proceeding. See, e.g., NS-PGL Ex. 12.0 REV at 11; NS-PGL Ex. 22.0 at 2; COC Ex 3.0 at 3; PIO Ex. 1.0 at 5; PIO Ex. 2.0 at 7. The City emphasizes that, by opening a proceeding to address these issues, the Commission can take proactive steps to protect consumers from unnecessary stranded costs as the State and City move forward with an increasingly electrified energy sector. The City asserts that this proceeding will provide a forum for joint problem-solving and allow the State to develop an equitable path to a cleaner future, which addresses the needs of labor, ratepayers, and other stakeholders. The City adds that action at this state-wide level will in turn inform specific investments in rate proceedings going forward.

The City argues that there is ample support in the Act for the Commission to open an investigation to analyze how gas utilities’ operations need to align with decarbonization efforts. The Commission was created to exercise general supervision over all Illinois public utilities in accordance with the Act. Sheffler v. Commonwealth Edison Co., 399 Ill. App. 3d 51, 60 (1st Dist. 2010) citing 220 ILCS 5/401. The Act also provides the Commission with authority to ensure “just, reasonable, safe, proper, adequate or
sufficient rules, regulations, practices, equipment, appliances, facilities, service or methods to be observed, furnished, constructed, enforced or employed.” 220 ILCS 5/8-501. Section 10-101 grants the Commission authority to “hold investigations, inquiries and hearings concerning any matters covered by the provisions of this Act, or by any other Acts relating to public utilities subject to such rules and regulations as the Commission may establish.” 220 ILCS 5/10-101. The City highlights that, in construing the scope of the Commission’s authority, the Illinois Appellate Court found that “[t]he Commission may adopt reasonable and proper rules and regulations relative to the exercise of its powers and functions.” Alhambra-Grantfork Tel. Co. v. Ill. Commerce Comm’n, 358 Ill. App. 3d 818, 823 (2005). The City argues that a comprehensive investigation into gas utilities’ decarbonization plans is well within the authority the Legislature provided to the Commission.

The City further emphasizes that the purpose of the Act fully encompasses “future of gas issues.” The City asserts that this purpose requires “the provision of adequate, efficient, reliable, environmentally safe and least-cost public utility services at prices which accurately reflect the long-term cost of such services and which are equitable to all citizens.” 220 ILCS 5/1-102. As to environmental quality, the Act requires “the protection of the environment from adverse external costs of public utilities services.” Id. The Act also demands that “[e]very public utility subject to this Act shall provide service and facilities which are in all respects adequate, efficient, reliable and environmentally safe and which, consistent with these obligations, constitute the least-cost means of meeting the utility’s service obligations.” 220 ILCS 5/8-401. Thus, the City maintains that the Commission has a vital role in effectively and comprehensively regulating public utilities to ensure customers receive adequate, efficient, reliable, environmentally safe, and least-cost public utility service. 220 ILCS 5/1-102. The City asserts that the Act makes clear that considering the economic and environmental impact of public utility service—including the GHG impact of gas infrastructure and demand—is a core regulatory function of the Commission.

City witness Deleon highlights that state commissions and gas utilities across the country have recognized the importance of addressing “future of gas” issues. Dr. Deleon points out that at least twelve other jurisdictions are in the midst of studying these issues in “future of gas” proceedings. See COC Ex 1.0 at 14-16 (detailing actions by state commissions in Massachusetts, New York, Colorado, and Minnesota); NS-PGL Ex. 22.0 at 10-11 (detailing additional proceedings).

The City argues that the record in this proceeding further demonstrates the need for action. The City argues that, unlike its peers who have taken action to address “future of gas” issues in individual cases (COC Ex 1.0 at 16-19), PGL’s apparent strategy is to double-down on continued investment in its gas system and ignore electrification initiatives altogether. See PGL Response to Commissioners’ Question No. 4 at 1. The City also highlights that Staff characterized PGL’s response as a “decision not to engage with the issue or [not to] provide a basis for accommodating an electrification transition.” Staff Reply to PGL Response to Commissioners’ Question No. 4. The City argues that other record evidence further elucidates this failure to plan.

The City takes the position that there is good reason that multiple stakeholders are calling for the same action, and that failure to take action now could pose additional risks
for the entire State as it proceeds with its energy transition. Finally, the City argues that it appears that PGL is waiting for Commission action in a Future of Gas proceeding to inform its investment decisions. The City points out that when asked to provide analyses assessing the impact of decarbonization policies on future throughput and infrastructure needs, PGL stated that "[n]o specific studies have been conducted of how, when or where to do [infrastructure upgrades] to accommodate lower carbon fuels, in part because there has been no Illinois 'Future of Gas' proceeding to clarify the scope of possibilities and the regulatory policies that will accompany them." COC Ex. 3.04. The City contends that PGL is not willing to plan for the "Future of Gas" unless the Commission requires PGL to do so.

The City argues that the decline in fossil fuel use raises many questions for the Commission to consider. Dr. Deleon set forth several recommendations to begin to define the scope of such a proceeding. First, "[a]ny proceeding opened by the Commission would benefit from a clear schedule, delineated phases, and robust stakeholder participation—including input from electric utilities in the state.” COC Ex. 3.0 at 23. Dr. Deleon also explained that such a proceeding should include a state-wide decarbonization analysis which builds upon the work already completed in ComEd's Illinois Decarbonization Study, a determination regarding the highest and most valued use of alternative fuels such as hydrogen, and joint gas-electric system planning. COC Ex. 3.0 at 23. For all of these reasons, the City urges the Commission to open this much-needed inquiry.

(ii) Infrastructure Plans

The City supports PIOs' recommendation regarding enhanced gas system planning.

(b) Non-Pipeline Alternative Analyses for Major Pipeline Projects

The City states that, on numerous occasions throughout this proceeding, Peoples Gas has indicated that it has not conducted any studies or analyses or begun planning for the clean energy transition. See, e.g., COC Ex. 1.0 at 27, 28; PIO Ex. 1.0 at 22-23; COC Exs. 1.04; 1.08, 1.09. The City further states that a "future of gas" proceeding is very likely to last several years (see, e.g., NS-PGL Ex. 22.0 at 6; COC Ex. 3.0 at 8) and, in the meantime, PGL will continue spending hundreds of millions of dollars on long-lived gas system infrastructure, as the City and State move forward on decarbonization (see PIO Ex. 1.0 at 64; AG Ex. 6.0R at 7). The City argues that, therefore, planning for the future should not be contingent upon the Commission opening a "future of gas" proceeding. The City argues that any new capital investments must be scrutinized in light of the energy transition reality, with full consideration of potential alternatives and an understanding of the emissions and cost implications of long-lived new gas infrastructure. To this end, the City asks that the Commission order PGL to conduct an analysis of NPAs and a GHG Emissions Analysis.

City witness Deleon explains that NPAs generally refer to any targeted investment or activity intended to defer, reduce, or remove the need to construct or upgrade aspects of a gas system. COC Ex. 1.0 at 32. Dr. Deleon asserts that NPAs can have substantial benefits for gas utilities and their customers, including cutting costs for ratepayers (COC
Ex. 1.0 at 32; PIO Ex. 1.0 at 37); reducing the risk of stranded assets (PIO Ex. 1.0 at 37; PIO Ex. 2.0 at 25); and lowering emissions. PIO Ex. 1.0 at 37.

The City argues that, while PGL provides an analysis of alternatives pursuant to 83 Ill. Adm. Code 285.6100, in most cases, the “alternatives” considered are merely one sentence, with no supporting quantitative analysis. COC Ex. 3.0 at 11. She further highlights that, when the City requested copies of “all benefit-cost analyses used to justify, scope, or design any of the Program elements proposed for 2024” (COC Ex. 3.02 at 1), PGL provided its “business case authorizations,” which the City argues show no more substantive analysis.

The City urges the Commission to direct PGL to provide an analysis of NPAs for investments in major capital projects as defined in 83 Ill. Adm. Code 285.6100. The City asserts that an alternatives analysis should include, for all alternatives considered: expected service life of any new infrastructure; an evaluation of the risk that the investments become stranded assets; the impact of each alternative on the gas system (e.g., pressure relief or leak reduction); an evaluation of estimated customer bill impacts; and a full cost-benefit analysis, including an assessment of the GHG emissions impact of any new infrastructure.

The City argues that this type of analysis can assist the Commission and stakeholders in exploring lower cost and lower emission options for gas infrastructure investments while keeping in mind the impacts of these decisions on customers.

The City argues that it is precisely these benefits that have led several experts in this proceeding (in addition to Dr. Deleon) to recommend NPAs. See PIO Ex. 1.0 at 41, AG Ex. 2.0 at 5, AG Ex. 3.0 at 34. The City adds that the soundness of the recommendation to simply consider NPAs is confirmed by other state commissions’ statements that NPAs should be “explored as a universal practice” for “traditional investments.” COC Ex. 1.0 at 32-33. The City argues that there is simply no excuse for PGL’s failure to consider NPAs today.

(iv) PIOs’ Position

PIO assert that traditional cost of service regulation incentivizes Peoples Gas to continue to make capital investments in its transmission and distribution infrastructure, despite the likelihood that the Company’s sales will continue to decline in the future. These investments add to the rate base and generate shareholder returns for Peoples Gas. PIO maintain that this incentive structure made sense when Illinois’ primary policy goal was to encourage gas utilities to add new customers and provide its customers with cheaper heating.

PIO explain that while ensuring affordability remains an important policy goal, other policy and market conditions in Illinois have evolved. PIO witness Neme’s analysis shows that electrification is a cost-effective alternative for the Company’s residential customers. PIO Ex. 2.0 at 4-6. Further, Illinois now has a better understanding of the dangers of greenhouse gas emissions associated with natural gas leakage and combustion, among other sources. Illinois has therefore established a policy goal of fully decarbonizing its energy sector and significantly reducing greenhouse gas emissions. PIO assert that it is well-understood that those reductions will require significant curtailment in natural gas.
use in buildings through demand-side measures like energy efficiency and electrification, which again calls into question the prudence of Peoples Gas’ investments in gas delivery infrastructure. PIO Ex. 1.0 at 55-56. Thus, PIO posit that the actions that cost of service regulation incentivize—such as building out system capacity—are not well-aligned with Illinois’ policy goals.

PIO state that the Commission should take sensible actions in this proceeding to discipline Peoples Gas’ capital infrastructure spending going forward. To that end, PIO recommend the Commission issue specific directives in its Order with respect to NPAs analysis; line extension allowances; gas system planning; and performance-based regulation.

(a) Performance-Based Ratemaking

To better align the Company’s incentives with its customers’ and the state’s interests, PIO request that the Commission begin the process of developing and implementing PBR. PBR encompasses several regulatory mechanisms that can better allocate risks, contain costs, and tie utility revenue to outcomes that are good for Peoples Gas’ customers. Id. at 85-86.

As a first step, PIO request that the Commission direct the Company to track and report on the performance metrics described in PIO witness Cebulko’s testimony. See id. at 87-91. They state that these metrics will help the Commission and stakeholders understand how the Company is performing today, and lay the groundwork for a future, more comprehensive PBR framework that attaches incentives and penalties to performance metrics. PIO assert that the Commission has ample authority to direct the Company to track and report on performance metrics under the Act, and has previously issued similar directives. For example, the Commission directed Ameren to annually report on incremental revenue generated by electric vehicles in the utility’s beneficial electrification proceeding. Ameren Ill. Co., Docket No. 22-0431/22-0443 (cons.), Order at 132-133 (Mar. 23, 2023, amended May 8, 2023). The Commission concluded that the data would be useful in developing future beneficial electrifications plans. Id. In addition, the Commission recently ordered ComEd and Ameren to annually report on tracking metrics for the purpose of creating future performance incentive metrics. See Ameren Ill. Co., Docket No. 22-0063, Order at 220-249 (Sept. 27, 2022, amended Nov. 10, 2022). PIO assert that, similarly, here, the performance metrics Mr. Cebulko recommends will aid the development of a future PBR structure.

PIO maintain that while Peoples Gas already tracks certain metrics connected to safety/reliability and customer satisfaction, along with a few metrics connected to energy efficiency, it does not track all the metrics that Mr. Cebulko recommends. In particular, Peoples Gas does not track several of Mr. Cebulko’s recommended metrics in the “Capital Efficiency” category. PIO Ex. 1.0 at 92. Those gaps include, for example, metrics connected to the percentage of projects that are over budget, which will be critical to ensuring that customers’ money is being spent efficiently. Id. at 92. PIO request that the Commission therefore direct the Company to track and report on an expanded set of tracking metrics, which would create a valuable foundation for a more comprehensive PBR framework in the future. Id. at 91-92. PIO also assert that it is important that the
Commission direct Peoples Gas to report its performance on each metric in a single docket to provide transparency and streamline tracking and comparison across time.

(b) Gas System Planning

PIO assert that gas system planning can help ensure Peoples Gas’ capital expenditures do not undermine the state’s climate and affordability objectives. PIO note that gas utilities in Illinois are not currently required to conduct transparent, long-term system planning. PIO state that while Peoples Gas likely engages in internal system planning, the Company does not submit a public long-term system plan. Given the inherent information asymmetry between the utility and the Commission (and the public at large), PIO explain that the lack of any transparent planning process makes it challenging for the Commission, customers, and other stakeholders to determine whether Peoples Gas is prioritizing least-cost, least-risk, prudent investments that are likely to be used and useful.

PIO emphasize that gas system planning is particularly critical in light of the state’s decarbonization goals and the likely impacts of electrification on natural gas distribution infrastructure. PIO note that rate cases are not a sufficient substitute for transparent long-term planning, but long-term planning can aid the Commission in future rate cases.

Additionally, PIO states that while Peoples Gas may be an important stakeholder in the clean energy transition, the Commission cannot and should not rely on Peoples Gas to plan its system in a manner that is consistent with the state’s affordability, safety, reliability, and climate goals without oversight. Instead, PIO request that the Commission initiate transparent planning processes that, among other things, help the Commission assess the impacts of electrification on the Company’s system, manage the pace of the Company’s investments, and mitigate customer bill impacts.

For these reasons, PIO recommend two, separate planning processes. The first is a one-time, statewide “Future of Gas” proceeding that commences shortly after the conclusion of this rate case and involves all of the utilities in the state. The Future of Gas proceeding would be aimed at evaluating the role of natural gas utilities in meeting the state’s decarbonization goals. The second is a long-term gas infrastructure planning requirement, under which each utility, including Peoples Gas, would be required to submit utility-specific biennial gas infrastructure plans starting in 2025.

(i) Future of Gas Proceeding

PIO maintain that a Future of Gas proceeding would give utilities (electric and gas), the Commission, and stakeholders the opportunity to holistically assess the state’s future resource needs; assess the cost, availability, and emission reduction potential of energy supply options; assess the role that the natural gas system can and should play in meeting the state’s decarbonization goals; and establish a set of expectations for gas utilities. Id. at 68-69. PIO note that the Commission could also use this proceeding to develop additional details regarding the implementation of a long-term gas infrastructure planning process.

(ii) Infrastructure Plans

PIO request that the Commission order Peoples Gas to file a gas infrastructure plan every two years, with the first filing to occur on July 1, 2025. PIO witness Cebulko
proposes a specific structure for that infrastructure planning process, consistent with the structure of similar gas planning processes in other states. *Id.* at 66-73.

PIO request that the Commission require that the plan include, at minimum:

- A description of the lowest societal cost distribution system investments necessary to meet customer demand and comply with public policy objectives;
- A 20-year planning horizon with a 5-year action plan of investments;
- The estimated total cost and annual increment revenue requirement of the proposed action plan;
- Comparative evaluations of resource procurements and major capital investments;
- Scenario and sensitivity analysis for the purposes of testing the robustness of the utility’s portfolio and investments under various parameters;
- A list of all proposed system expenditures and investments, including an analysis of infrastructure needs and detailed information on all planned projects within the action plan;
- The analyses and results of the NPA analysis of major projects consistent with the recommendation above;
- A demonstration that the plan will minimize rate impacts on customers, particularly low-income households and households within equity investment eligible communities;
- A demonstration that the plan complies with all applicable Commission rules and jurisdiction requirements;
- Distribution mapping that identifies areas of constraint and risk, location of planned projects, pressure districts served by the individual project, locations of environmental justice communities, and emissions in environmental justice communities;
- A summary of stakeholder participation and input, as well as an explanation of how Peoples Gas incorporated this input into the plan. For all projects located within equity investment eligible communities, the utility must describe its outreach to members of that community and findings from those efforts;
- Publicly filed workpapers documenting all inputs and assumptions with limited use of confidentiality; and
- An analysis of the emissions associated with the utility supplied fuel.

*Id.* at 72-74. Moreover, PIO recommend the Commission direct utilities to file a work plan prior to its gas infrastructure plan filing, outlining the content of its long-term plan, the methods for assessing potential resources, and other items. Finally, PIO request that the Commission contract with a third party to develop a range of load and demand forecasts.
for each utility that the Commission and stakeholders can use to determine the necessity of the Company’s investments given projected demand.

(c) Non-Pipeline Alternative Analyses for Major Pipeline Projects

PIO explain that NPAs are the gas sector’s equivalent of the electric sector’s “non-wires alternatives.” They refer to activities or investments that delay, reduce, or avoid the need to build or upgrade traditional gas system infrastructure such as pipelines, storage, and peaking resources. PIO Ex. 1.0 at 36. NPAs include a variety of actions, strategies, programs, or technologies on both the demand-side and supply-side of the utility’s operations, including targeted demand response, targeted energy efficiency, electrification, and other solutions. See id. at 36, Figure 4. While NPAs can consist of a single demand- or supply-side resource, utilities more often deploy a portfolio of resources. Id. at 36. PIO maintain that NPAs are ideal candidates for projects involving costly upgrades and recovery windows that extend far into the future—a description that fits several of Peoples Gas’ plant additions proposed in this case.

PIO state that NPAs will be critical in the coming years to manage the Company’s risk of stranded assets. By considering solutions other than capital investment in the gas delivery system to meet system needs, NPAs can save ratepayers money in the long-term, because NPAs are often cheaper than system expansion. Id. at 37. By limiting upfront capital investments, NPAs also help to manage the risk of stranded assets in the future. By avoiding the expansion or retention of gas infrastructure, NPAs also help avoid future emissions from gas infrastructure. PIO note that utilities and regulators in other states are already exploring, evaluating, and implementing NPAs.

PIO explain that Peoples Gas does not consider NPAs in its capital investment decision-making. In response to a PIO discovery request, the Company stated it “is currently not aware of any non-traditional investments that would cover the reliability, sustainability, and affordability necessities of our customers.” PIO Ex. 1.2 at 24 (Peoples Gas response to PIO-PGL 2.07). PIO assert that Peoples Gas’ failure to consider NPAs calls into question whether the Company’s capital investments represent the least-cost means of meeting its service obligations, as Section 8-401 of the Act requires, and puts ratepayers at risk of funding long-lived capital investments that the Company might have avoided.

In response to PIO’s arguments, Peoples Gas witness Graves asserts that NPAs are not a “silver bullet” that will allow Peoples Gas to avoid SMP-like investments because NPAs have had limited impact to date and require customer engagement to implement. NS-PGL Ex. 33.0 at 21. PIO state that this argument appears to suggest that the Commission should not implement NPAs simply because they are nascent. PIO maintain that the Commission should reject this argument for four reasons. First, this argument minimizes the impact that NPAs can have. As described above, states have already implemented frameworks for NPAs to be considered for large projects and New York demonstrated how to effectively implement this framework. Second, requiring an NPA analysis is a “no-regrets” step, because carrying out the analysis does not, in and of itself, require the Company to retire or add any investments. Rather, conducting an alternatives analysis is consistent with the Company’s existing obligation to provide least-cost service
to its customers. 220 ILCS 5/8-401. Third, the Company does not propose to pause capital spending until after an energy transition proceeding, so there is no reason for this Commission to wait on disciplining that spending. Fourth, establishing an NPA analysis requirement would not preclude the Commission from refining that requirement in future planning or rate case proceedings. As PIO witness Cebulko explains, “the Commission can establish an NPA requirement for capacity expansion and reliability projects in this rate case, and then initiate a separate proceeding to develop an NPA framework (including, for example, NPA screening criteria.)” PIO Ex. 4.0 at 28.

PIO request that the Commission therefore direct Peoples Gas to conduct an NPA analysis for all major pipeline projects (where “major projects” are defined as consistent with 83 Ill. Adm. Code 285.6100). They state this analysis will help limit unnecessary capital expenditures and drive rate reductions for ratepayers. PIO note that the Commission has the power to direct the Company to adopt an NPA assessment framework in this proceeding pursuant to its power to set just and reasonable rates and practices under Section 9-201(c). The Commission used this authority in ComEd’s beneficial electrification proceeding where it ordered the utility to include in all future beneficial electrification plan filings an analysis detailing the impacts of the plan on customer rates. Commonwealth Edison Co., Docket No. 22-0432/22-0442 (cons.), Order at 198 (Mar. 23, 2023, amended May 8, 2023).

(v) Commission Analysis and Conclusion

Many of the AG’s and PIOs’ proposals related to the clean energy transition are discussed elsewhere in Section IV of this Order because they involve proposed disallowances to rate base. The Commission notes that parties disagree on the appropriate proceeding to address many of the AG and PIO proposals and, to be clear, the format of this Order does not reflect a determination that certain proposals are or are not appropriate to consider as part of a rate case.

Electrification

The Companies’ responses to Commissioner Question 4 insufficiently answered the Commission and signaled that they are not currently working towards the electrification goals of the State. See Responses to Commissioners’ Questions, ICC 1.04. Both North Shore and Peoples Gas asserted they have not “modeled, nor is it plausible to assume, a scenario where customers’ energy needs are fully met through electrification.” Id. at 2-3. Despite that response’s inattention to less extreme scenarios, the Companies’ own electrification witness authored a report finding “almost half of non-electricity gas demand has a likelihood to be electrified,” with particularly high electrification potential for space and water heating. PIO Ex. 4.1 (Graves Brattle Report), at 37; see also PIO IB at 15-16.

The Companies cite uncertain timelines, supply resource adequacy, and future utilization of low and zero carbon energy options as justification for their lack of electrification modeling. See Responses to Commissioners’ Questions, ICC 1.04, at 2-3. Neither Company sufficiently explains how uncertainties prevented it from analyzing and mitigating impacts of electrification on its business and customers. PIO notes that a prudent utility should (1) survey the available facts and unknowns related to electrification, model electrification scenarios; (2) analyze the potential impacts of those scenarios on its
throughput, peak demand, customer counts, and other key variables, and (3) adjust its capital planning process accordingly. See PIO IB at 18. The purpose of using a test year is to make and present to the Commission informed assumptions and projections as to investments needed to accommodate customer needs and account for external factors on the service territory. Based on the record in this case, NS and PGL appear unwilling at this time to factor electrification scenarios into infrastructure planning.

**Long-Term Gas Infrastructure Plan**

The Commission agrees with PIO that while PGL and NS likely engage in internal system planning, the Companies did not submit a public long-term system plan, which creates an inherent information asymmetry between the Companies and the Commission. NS and PGL’s lack of transparent planning processes makes it challenging for the Commission, customers, and other stakeholders to determine whether the Companies are prioritizing just, reasonable, and prudent investments that are likely to be used and useful. The Commission therefore agrees that the Companies’ capital spending (and associated planning, budgeting, and project selection processes) merits careful consideration in this and future rate cases.

The Commission is statutorily tasked with general supervision of all public utilities and to ensure public utilities are prioritizing reasonable investments and practices. See *e.g.*, 220 ILCS 5/4-101 (the Commission shall generally supervise all public utilities and may keep itself informed as to various aspects of each utility); 220 ILCS 5/9-201(c) (the Commission shall find rates and other public utility charges to be just and reasonable); 220 ILCS 5/9-211 (a utility’s base rate shall include only prudently incurred investments). In furtherance of its mission, the Commission has broad investigatory authority and “shall inquire into the management of the business thereof and shall keep itself informed as to the manner and method in which the business is conducted.” 220 ILCS 5/4-101. The Commission also holds plenary power to “determine the just, reasonable, safe, proper, adequate or sufficient rules, regulations, practices, equipment, appliances, facilities, service or methods to be observed, furnished, constructed, enforced, or employed and it shall fix the same by its order, decision, rule, or regulation.” 220 ILCS 5/8-501. "It is a well-established rule that the express grant of authority to an administrative agency also includes the authority to do what is reasonably necessary to accomplish the legislature's objective." *Abbott Lab. V. Ill. Commerce Comm’n.*, 289 Ill. App. 3d 705, 712 (1st Dist. 1997).

To remedy the difficulty of obtaining information in this case and to aid in the Commission’s informed review of the Companies’ future rate increase requests, the Commission adopts certain reporting recommendations made by both the PIO and AG as identified below. PGL and NS shall file a long-term infrastructure plan (“Long-Term Gas Infrastructure Plan”) with the Commission every two years beginning July 1, 2025, including at a minimum:

- List of proposed system expenditures and investments, including analysis of infrastructure needs and detailed information on all planned projects within the action plan;
• Demonstration that each project or program plan complies with all applicable Commission rules and jurisdiction requirements, such as safety and reliability, among others;
• 5-year action plan of investments with a longer-term planning horizon analysis where applicable;
• Estimated total cost and annual incremental revenue requirement of the proposed action plan;
• Explanation for the pace of each project or program, including reasoning as to why the project or program cannot be deferred to future years;
• Comparative evaluations of resource procurements and major capital investments;
• Distribution mapping that identifies areas of constraint and risk, location of planned projects, pressure districts served by each project, and locations of environmental justice communities;
• Description of lowest societal cost gas distribution system investments necessary to meet customer demand and comply with public policy objectives;
• Demonstration that the program or project will minimize rate impacts on customers, particularly low-income and equity investment eligible communities;
• Scenario and sensitivity analysis to test robustness of utility’s portfolio and investments under various parameters;
• Publicly filed workpaper documenting all inputs and assumptions with limited use of confidentiality; and
• Summary of stakeholder participation and input and an explanation of how the Company incorporated stakeholder engagement.

No later than 12 months prior to the due date of the Long-Term Gas Infrastructure Plan, PGL and NS shall file a work plan that outlines at a minimum: (1) the content of the Long-Term Gas Infrastructure Plan; (2) the method for assessing potential resources; and (3) the timing and extent of public participation.

**Line Extension Allowances**

Next, the Commission addresses the PIOs’ proposed elimination or reduction of line extension allowances. The Commission agrees with PIO that the historic policy rationale for line extension allowances has changed. However, the broader question of eliminating all line extension allowances requires additional information and should be considered in the “Future of Gas” or a separate rulemaking proceeding. The Commission declines in this case to require a reduction in NS and PGL’s line extension allowances to the minimum level required by 83 Ill. Admin. Code 501.600. While the Commission declines to modify NS and PGL’s line extension allowances in this proceeding, it notes that discussions of line extensions in the “Future of Gas” need not prevent the
Commission or the Companies from modifying line extension allowances in other proceedings.

“Future of Gas” Proceeding

Parties of record have commented on the need for either a “Future of Gas” proceeding or a curtailment of infrastructure spending levels considering State policy as set forth by the Climate and Equitable Jobs Act (“CEJA”) (Public Act 102-0662). In CEJA, the State codified a goal of economy-wide, 100% clean energy by 2050. The Commission further recognizes that while CEJA endows the Commission and other state agencies with the authority to pursue decarbonization in the electric sector, the Act is silent as it relates to the gas system. If the decarbonization goals of CEJA are to be met, the gas distribution system as currently operated will need to change. The Commission will need to better define infrastructure spending by the State’s natural gas utility companies and lay the framework for how gas system operations will help meet the State’s clean energy goals.

The issues raised concerning the “Future of Gas” distribution need to be discussed, at the earliest time, and should include a broad range of stakeholders and other interested parties. A rate case is not the best place to address every proposal and issue raised by parties in this docket, with the notable exceptions of SMP project management as discussed in Section IV.B.1.a.v. and the Long-Term Gas Infrastructure Plan discussed above in this section. The Commission defers the rest of the proposals the AG, PIO, and City raise to be incorporated in a “Future of Gas” proceeding.

For the topics on which the Commission declines to act on in this proceeding, numerous parties necessary to conduct a thorough discussion are not present in this case, or in the other gas rate cases currently before the Commission. For example, changes to the gas distribution system will necessarily impact the electric distribution system. But the electric utilities are not participants in this case; nor are the frontline communities who need to be heard on distribution infrastructure in their communities. There are other parties essential to a “Future of Gas” discussion that are not part of this case.

This record is insufficient to reach decisions on some of the larger questions concerning the “Future of Gas,” including issues relating to decarbonization. Notably, the Commission sought answers to questions relating to electrification and the effects of state and federal policies that support electrification on the gas system. See Commission Questions filed on April 17, 2023. The responses, or lack thereof for certain questions, from the Company and intervenors clearly demonstrate the need for a “Future of Gas” proceeding that will provide the information needed to develop an informed plan for future investments and policies.

Accordingly, the Commission directs Staff to develop a plan for a “Future of Gas” proceeding that will include a timeline for workshops and a formal proceeding. The goal of this proceeding is to fully explore the issues involved with decarbonization of the gas distribution system. Recommendations for future Commission action, as well as any necessary legislative changes should be developed as part of the proceeding.
The proceeding shall discuss, at a minimum, the following categories of issues, which the Staff plan will further describe and expand upon:

- Potential for decarbonization of the existing gas system, including identification of technical constraints, hard to decarbonize end-uses, and methodologies for achieving decarbonization;
- If decarbonization requires a shift to electric distribution, the timing of such a shift;
- The role and scope of energy efficiency retrofits, for both residential and Commercial and Industrial end-users, to facilitate decarbonization;
- Cost considerations, including the protection of non-first movers from bearing a disproportionate cost of the remaining gas system;
- Stranded assets of the gas distribution system and planning methods to mitigate the issue, including non-pipeline alternatives;
- Evaluation of strategies for identifying and managing infrastructure that is nearing the end of its useful life or is no longer used and useful;
- The need for future integrated systems planning between gas and electric systems;
- The need for line extensions (for both mains and services) on the gas distribution system in the future and the need for a rulemaking to modify existing codified line extension allowances;
- The ability, costs, and timing of ramping up the electric distribution system to meet expanding load;
- Additional electric distribution infrastructure needed, and interaction with existing electric multi-year rate and spending plans;
- Potential uses for any existing gas infrastructure which may not be needed after the transition;
- The effects of federal and state public policy that supports electrification on the gas system;
- Legislative and regulatory changes needed to effectuate any needed transition;
- Issues unique to propane and other liquid fuel customers; and
- Other issues determined by the Staff to be necessary for the most thorough discussion possible.

The Commission notes that the scope and timeline of this proceeding may or may not be affected in the future by legislation or action from the State that addresses issues both within and beyond the scope listed above. As such, the Commission recognizes that changes to the “Future of Gas” proceeding may occur as issues are addressed through other means.

An Initiating Order shall be prepared by Staff within 90 days of this Order to effectuate this process.
V. OPERATING EXPENSES

A. Uncontested Issues

1. Other Revenues

North Shore’s and Peoples Gas’ forecasts of $1.5 million and $23.8 million, respectively, in other revenues are uncontested and are therefore approved. NS-PGL Exs. 24.01N and 24.01P REV at Schs. 1.01N and 1.01P, line 2, column I.

2. Payroll Expense

Companies witness Zgonc described in detail how their 2024 test year payroll budgets ($8.8 million for North Shore, $77.7 million for Peoples Gas, not including incentive pay) were developed by the business units to project staffing levels and payroll levels, NS Ex. 2.0 REV at 10–11; PGL Ex. 2.0 REV at 11; NS-PGL Ex. 24.01 N and P REV, page 1, line 5. No party contests the Companies’ payroll expense forecasts for 2024 and they are therefore approved.

3. Interest

   a. Budget Payment Plan

North Shore’s and Peoples Gas’ forecasts of $202,000 and $835,000, respectively, for interest expense on budget payment plan accounts are uncontested and are therefore approved. NS Ex. 2.1, Sch. C-2, line 40, column K; PGL Ex. 2.1, Sch. C-2, line 45, column L.

   b. Customer Deposits

The amount of interest expense for budget payment plan accounts includes interest expense for customer deposits, which is uncontested and therefore approved.

   c. Synchronization

Staff witness Mugera proposed an adjustment for interest synchronization to reflect Staff’s proposed adjustments to the Companies’ revenue requirements. Staff Ex. 1.0 at 6; Staff Sch. 1.06N & P. The Companies understand this to be a pass-through adjustment that would be accurate if the Commission adopts all of Staff’s proposed adjustments to the revenue requirement. NS-PGL Ex. 13.0 at 28. Based on those adjustments, the Companies calculated interest synchronization amounts of $8.7 million for North Shore and $84.9 million for Peoples Gas. See NS-PGL Ex. 13.01, Schs. 1.06N & P. These adjustments are approved subject to an appropriate interest synchronization adjustment to reflect the approved revenue requirement. NS-PGL Ex. 13.0 at 28.

4. Transmission

North Shore’s and Peoples Gas’ forecasts of transmission expense of $1.4 million and $1.8 million, respectively, are uncontested and therefore approved. NS-PGL Ex. 24.01N, Sch. 1.01N, line 8, column I; NS-PGL Ex. 24.01P REV, Sch. 1.01P, line 8, column I.
5. **Distribution**

   North Shore’s and Peoples Gas’ forecasts of distribution expense of $18.0 million and $149.5 million, respectively, are uncontested and are approved. NS-PGL Ex. 24.01N, Sch. 1.01N, line 9, column I; NS-PGL Ex. 24.01P REV, Sch. 1.01P, line 9, column I.

6. **Customer Accounts – Uncollectibles**

   North Shore’s and Peoples Gas’ forecasts of uncollectible accounts expense of $1.2 million and $47.0 million, respectively, are uncontested and are approved. NS-PGL Ex. 24.01N, Sch. 1.01N, line 4, column I; NS-PGL Ex. 24.01P REV, Sch. 1.01P, line 4, column I.

7. **Customer Accounts – Other than Uncollectibles**

   North Shore’s and Peoples Gas’ forecasts of other customer accounts expense of $5.9 million and $46.1 million, respectively, are uncontested and are approved. NS-PGL Ex. 24.01N, Sch. 1.01N, line 10, column I; NS-PGL Ex. 24.01P REV, Sch. 1.01P, line 10, column I.

8. **Customer Services and Information**

   North Shore’s and Peoples Gas’ forecasts of customer services and information expense of $399,000 and $1.7 million, respectively, are uncontested and are approved. NS-PGL Ex. 24.01N, Sch. 1.01N, line 11, column I; NS-PGL Ex. 24.01P REV, Sch. 1.01P, line 11, column I.

9. **Charitable Expense**

   In accordance with Section 9-227 of the Act, the Companies provide charitable contributions to organizations whose objectives benefit the public welfare or are for charitable scientific, religious, or educational purposes that serve to ensure the well-being and stability of the communities within their service territories and the customers residing in those communities. NS Ex. 2.0 REV at 29; PGL Ex. 2.0 REV at 31. The Commission has traditionally allowed recovery of charitable donations in the Companies’ rate cases, and, in keeping with their historical practice, the Companies provided additional information on the benefits of their charitable contributions beyond what is required by Part 285 of the Commission’s rules. NS Ex. 2.0 REV at 29; NS Ex. 2.1, Sch. C-7; PGL Ex. 2.0 REV at 31; PGL Ex. 2.1, Sch. C-7.

   Per Part 325 of the Commission’s rules, the Companies classified individually-identified sponsorships separately from institutional events. NS Ex. 2.0 REV at 30; NS Ex. 2.6; PGL Ex. 2.0 REV at 33–34; PGL Ex. 2.7. The Companies also employed additional processes for assessing rate recoverable charitable, sponsorship, and institutional events. NS Ex. 2.0 REV at 31; PGL Ex. 2.0 REV at 34–35. North Shore and Peoples Gas forecast $508,000 and $4.0 million, respectively, of charitable contributions in the test year. NS Ex. 2.1, Sch. C-2, Sch. C-7. These amounts are uncontested and are therefore approved.

10. **Lobbying Expense**

    The Companies did not propose any lobbying expenses in the test year. NS Ex. 2.1; PGL Ex. 2.1.
11. **Outside Professional Services Expense**

North Shore’s and Peoples Gas’ forecasts of outside professional services expense of $2.2 million and $24.7 million, respectively, are uncontested and are approved. NS Sch. C-6.2; PGL Sch. C-6.2.

North Shore’s adjusted test year amount for federal income taxes is $5.3 million. NS-PGL Ex. 24.01N, Sch. 1.01N. North Shore’s adjusted test year amount for state income taxes is $2.3 million. *Id.* Peoples Gas’ adjusted test year amount for federal income taxes is $54.4 million. NS-PGL Ex. 24.01P REV, Sch. 1.01P. Peoples Gas’ adjusted test year amount for state income taxes is $22.6 million. *Id.* No party contests these amounts, and they are therefore approved.

12. **Income Tax Expense**

North Shore’s adjusted test year amount for federal income taxes is $5.3 million. NS-PGL Ex. 24.01N, Sch. 1.01N. North Shore’s adjusted test year amount for state income taxes is $2.3 million. *Id.* Peoples Gas’ adjusted test year amount for federal income taxes is $54.4 million. NS-PGL Ex. 24.01P REV, Sch. 1.01P. Peoples Gas’ adjusted test year amount for state income taxes is $22.6 million. *Id.* No party contests these amounts, and they are therefore approved.

13. **Taxes Other Than Income Taxes**

North Shore’s and Peoples Gas’ forecasts of taxes other than income taxes expense of $5.1 million and $49.7 million, respectively, are uncontested and are approved. NS-PGL Ex. 24.01N, Sch. 1.01N, line 14, column I; NS-PGL Ex. 24.01P REV, Sch. 1.01P, line 14, column I.

14. **Gross Revenue Conversion Factor**

Staff witness Mugera proposed an adjustment for Gross Revenue Conversion Factor (“GRCF”) to reflect Staff’s proposed adjustments to the Companies’ revenue requirements. Staff Ex. 1.0 at 6–7; Staff Sch. 1.07N & P. The Companies understand this to be a pass-through adjustment that would be accurate if the Commission adopts all of Staff’s proposed adjustments to the revenue requirement. NS-PGL Ex. 13.0 at 28. Based on the adjustments, the Companies calculated GRCF amounts of $1.4 million (with and without bad debt) for North Shore, and $1.5 million (with bad debt) and $1.4 million (without bad debt) for Peoples Gas. See NS-PGL Ex. 13.01, Schs. 1.07N & P. No party contests these adjustments, and they are therefore approved, subject to an appropriate GRCF adjustment to reflect the approved revenue requirement. NS-PGL Ex. 13.0 at 28.

15. **Administrative and General**

North Shore’s and Peoples Gas’ forecasts of administrative and general expense of $17.2 million and $105.8 million, respectively, are uncontested and are approved. NS-PGL Ex. 24.01N, Sch. 1.01N, line 12, column I; NS-PGL Ex. 24.01P REV, Sch. 1.01P, line 12, column I.
16. **Depreciation Expense**

North Shore’s and Peoples Gas’ forecasts of depreciation expense of $20.0 million and $228.0 million, respectively, are uncontested and are approved. NS Ex. 2.1, Sch. C-1, line 33, column G; PGL Ex. 2.1, Sch. C-1, line 35, column G.

17. **Amortization Expense (Other than Rate Case Expense)**

With the exception of contested rate case expense (see Section V.B.2), North Shore’s and Peoples Gas’ forecasts of amortization expense of $2.6 million and $18.2 million, respectively, are uncontested and are approved. NS Ex. 2.1, Sch. C-1, line 34; PGL Ex. 2.1, Sch. C-1, line 36.

18. **WEC Business Services General and Administrative Cross Charges**

North Shore’s and Peoples Gas’ forecasts of WBS general and administrative cross charges expense of $23.0 million and $164.7 million, respectively, are uncontested and are approved. NS Ex. 2.1, Sch. C-13, line 21; PGL Ex. 2.1, Sch. C-13, line 27.

19. **Bad Debt**

Companies witness Zgonc testified that under the net write-off method, the bad debt expense at present rates as adjusted would be the average of the actual write-offs for calendar years 2019 to 2021, which is $3.3 million for North Shore and $52.4 million for Peoples Gas, less $2.3 million for North Shore and $19.6 million for Peoples Gas in gas costs expected to be recovered under Rider UEA-GC, for a net total of $1.0 million for North Shore and $32.7 million for Peoples Gas. NS Ex. 2.0 REV at 19; PGL Ex. 2.0 REV at 21; NS Ex. 2.1, Sch. C-1, line 27; PGL Ex. 2.1, Sch. C-10, line 29. This methodology and these figures, which support the Companies’ customer accounts projections, are uncontested and are approved.

20. **Intervenor Compensation**

Staff witness Mugera recommended that the Companies each contribute $500,000 to the Consumer Intervenor Compensation Fund. Staff Ex. 1.0 at 18–20. The Companies agree that Section 9-229(4) of the Act requires these contributions, and they have included these amounts as rate case expenses subject to recovery in rates. NS-PGL Ex. 13.0 at 29; see also NS-PGL Ex. 24.04 REV. These amounts are uncontested and approved.

21. **Company-Use Gas**

Staff witness Mr. Seagle recommended that the Companies be required to provide the most up-to-date information relating to company-use gas. Staff Ex. 7.0 at 9–10. In rebuttal testimony, the Companies agreed to do so. NS-PGL Ex. 13.0 at 29–30. The updated amounts for company-use gas, $134,597 for North Shore and $1.9 million for Peoples Gas, are uncontested and are approved. NS-PGL Ex. 13.06.

22. **Company-Use Fuel**

Staff witness Seagle recommended that the Companies provide the most up-to-date information relating to company-use fuel. Staff Ex. 7.0 at 8–9. In rebuttal testimony, the Companies agreed to do so. NS-PGL Ex. 13.0 at 29–30. Based on the most up-to-
date information, the 2024 fleet fuel costs decreased from $566,000 to $391,000 for North Shore (with $135,000 of this reduction allocated to O&M), and from $2.8 million to $2.0 million for Peoples Gas (with $469,000 of this reduction allocated to O&M). See NS-PGL Ex. 24.01P REV, Sch. 1.02 P, page 3. These amounts are uncontested and are approved.

23. **North Shore In-House Locate Pilot Program**

Staff witness Daniel recommended that North Shore establish a pilot program to use in-house employees to conduct locating for 10% of requests submitted to Joint Utility Locating Information for Excavators (“JULIE”) within North Shore’s service territory. Staff Ex. 8.0 REV at 7. Under the pilot, North Shore would be required to provide Staff a weekly report on the locate requests completed to date, including JULIE number, address, city, date completed, locator name, and photographic documentation with date and time stamp, and Staff would conduct random auditing of completed locates during the pilot program. *Id.*

Companies witness Eldringhoff explained that while Staff’s proposal was not directed to Peoples Gas, Peoples Gas is creating 20 in-house locate positions in 2023-2024, with the overall goal of attaining cost savings and increasing effectiveness of locate services. She stated that North Shore intends to leverage the findings from the Peoples Gas locate program to implement its own program and requested flexibility to negotiate with Local 2285 regarding the creation of in-house locate positions as part of the labor bargaining process during the second quarter of 2024. NS-PGL Ex. 14.0 REV at 11, 12.

In response, Mr. Daniel adjusted his proposal to require that North Shore implement the in-house locate pilot program by April 1, 2025, to allow the company time to garner insight from the Peoples Gas in-house locating program and to engage in union negotiations, with monthly progress updates on the status of implementation following the Commission’s Final Order in this proceeding. Staff Ex. 16.0 at 2. Mr. Daniel maintained his position, however, that North Shore should complete 10% of the locate requests submitted through JULIE using in-house personnel versus contracted labor. *Id.* at 2–3.

Ms. Eldringhoff, in surrebuttal testimony, stated that the Companies found Mr. Daniel’s adjusted timeline to be reasonable and agreed to fully implement the pilot by April 1, 2025. See NS-PGL Ex. 24.0 at 9. Ms. Eldringhoff further testified that while North Shore recognizes Mr. Daniel’s concerns with its past performance, it has taken steps to improve its ability to respond to the volume of locate requests submitted to JULIE, including, for example, holding biweekly meetings with locate contractors to ensure staffing is sufficient to keep up with the workload, and that North Shore has considerably reduced its 2023 “no show” rate to a level comparable to that of Peoples Gas. *Id.* at 10–11. North Shore stated that it will continue striving to improve its locate services performance, including implementation of Staff’s pilot with a 10% target percentage based on the current average volume of locate requests, and that it believes it can onboard and train the necessary company personnel to meet this goal of 10% volume while also being able to leverage already-established contractors if required to respond to a sudden increase in locate requests. North Shore estimates the cost to achieve this 10% target percentage is $247,000 in additional labor expense. North Shore’s rebuttal filing included
a corresponding increase to the revenue requirement and this adjustment is approved. NS-PGL Ex. 13.1N, Sch. 1.02 N.

Finally, with respect to reporting requirements, Ms. Eldringhoff testified that while North Shore is not opposed generally to reporting on its progress of performing locate requests, it questions the need to do so. Based on the data already available to Staff, as evidenced in Mr. Daniel’s direct and rebuttal testimony, Staff can easily calculate current no-show rates and thus monitor overall locate performance. North Shore recommends that any additional reporting requirements be directed towards improved performance monitoring. NS-PGL Ex. 24.0 at 12.

The Commission agrees that North Shore should establish a pilot program to use in-house employees to conduct locating for 10% of requests submitted to JULIE within North Shore’s service territory. North Shore has agreed with Staff that this program will be implemented by April 1, 2025, to allow North Shore time to develop and implement the program. The Commission recognizes that it takes time to negotiate collective bargaining agreements, hire and train employees and to properly implement new protocols, systems and reporting requirements for the pilot. The Commission urges North Shore to quickly implement the pilot program before the 2025 deadline. The Commission agrees with Staff that proposed weekly reporting requirements are necessary at this time to monitor overall locate performance and ensure that North Shore is held accountable, and therefore adopts Staff’s reporting requirements prior to program implementation.

24. Other

Staff witness Seagle recommended that the Companies provide the most up-to-date information for the volume and cost of their gas in storage. Staff Ex. 7.0 at 7–8. In rebuttal testimony, the Companies provided a revised version of Schedule F-9 reflecting the most current information as of March 2023. NS-PGL Ex. 13.0 at 29; see also NS-PGL Ex. 13.04. The effect of these updates on the revenue requirement is a $29,000 decrease to North Shore and a $2.2 million increase to Peoples Gas. NS-PGL Ex. 13.0 at 29. The revised amounts are uncontested and are approved.

There are no other issues related to operating expense that are required to be discussed here.

B. Contested Issues

1. Amortization Period for Rate Case Expense

a. Companies’ Position

The Companies state that North Shore proposed an amortization period for its rate case expense of two years, and that proposal was not contested. Staff Ex. 1.0 at 14–16.

The amortization period for Peoples Gas’ rate case expense had been treated as uncontested following a compromise at four years, as described in Staff’s and the Companies’ Initial Briefs. Staff IB at 50; NS-PGL IB at 117–118. However, the Companies state that in its Initial Brief, CUB/PCR/City now support Staff witness Alan’s pre-compromise six-year amortization period, reasoning that it best represents the nine-year period since Peoples Gas last filed a rate case, and avoids “the risk of utility over-recovering by several times the actual amount of its rate case expense if the Commission
approves too short an amortization period." CUB/PCR/City IB at 16–17. Importantly, however, Staff no longer supports the six-year amortization period. Staff IB at 50.

The Companies aver that it is well established that rate case expenses should be amortized “over the period of time that the subject tariffs are reasonably anticipated to be in effect.” Ill. Bell Tel. Co., Docket No. 89-0033, Order at 78 (Nov. 9, 1989). The Companies originally proposed to amortize and recover rate case expenses over two years, based on the Companies’ historic cadence for filing rate cases. PGL Ex. 2.0 REV at 30–31; NS Ex. 2.0 REV at 28. Staff witness Mugera recommended a six-year amortization period for PGL in his direct testimony, reasoning that six years represented the average length of time between PGL’s last three rate cases. Staff Ex. 1.0 at 14–16.

While Mr. Mugera’s calculation of time between rate cases was accurate, it does not reflect the likely cadence of Peoples Gas’ rate cases going forward. NS-PGL Ex. 13.0 at 23. Because the legislation underlying Peoples Gas’ Rider QIP will expire at the end of 2023, PGL will need to file rate cases much more regularly—at least every two years, if not annually—to recover the costs of its SMP program. Id. at 24. In response, Mr. Mugera proposed a compromise amortization period for Peoples Gas’ rate case expenses of four years, which he described as an “attempt . . . to address the company’s concerns due to the potential impact of the QIP sunset at the end of 2023 on the frequency of future rate case filings.” Staff Ex. 9.0 at 23. For purposes of narrowing the issues in the rate case, Peoples Gas agreed to a four-year amortization period for rate case expenses. NS-PGL Ex. 23.0 at 7.

As a result of this compromise between the Companies and Staff, the undisputed amortization periods for Peoples Gas’ and North Shore’s rate case expense are four and two years, respectively. CUB/PCR/City has not presented any additional or new arguments supporting a six-year amortization period. The Companies contend that the Commission should therefore adopt the compromise agreed to by Staff and Peoples Gas and reject CUB/PCR/City’s last-minute adoption of Staff’s now-abandoned position.

b. Staff’s Position

Staff argues that the Commission should adopt Staff’s proposed 4-year amortization period for rate case expense for Peoples Gas and two years for North Shore, which the Companies agreed to in surrebuttal testimony for purposes of narrowing the issues in this proceeding. Staff Ex. 9.0, 23; NS-PGL Ex. 23.0 at 7.

In direct testimony, Staff presented an adjustment for Peoples Gas to increase the amortization period from the proposed 2-year period to a more reasonable 6-year amortization period, based on Peoples Gas’ rate case history. Staff Ex. 1.0 at 14. The increase in the amortization period results in a lower annual expense to be included in the revenue requirement. Id. at 14-15. Staff notes that Peoples Gas’ last rate case was Docket Nos. 14-0224/14-0225 (cons.) with a Final Order issued January 21, 2015, a period of nine years based on the test year of 2024. The rate case amortization period set in Peoples Gas’ last rate case was 2.5 years. In other words, Peoples Gas collected rate case expense for an extra 6.5 years.

Staff proposed a 6-year amortization period which represents an approximate average between the time of Peoples Gas’ most recent rate case (9 years) and its
proposed amortization period (2 years). Staff argues a short amortization period needlessly puts the customers at risk and the risk is asymmetrical. Staff explains that if the length between rate cases is longer than the amortization period, the customers will pay more than the intended amount with no recourse. However, if the length between rate cases is shorter than the amortization period, any unamortized portion of rate case expense from the prior rate case can be added to the current amount and amortized over the new Commission-approved amortization period. The company is made whole. The customers, however, do not have such protections in place. Id. at 15-16.

In rebuttal testimony, Staff adjusted its proposed rate case expense amortization to reflect a 4-year amortization period for Peoples Gas. Staff Ex. 9.0 at 23. The 4-year amortization period attempts to address PGL’s concerns due to the potential impact of the QIP sunset at the end of 2023 on the frequency of future rate case filings. NS PGL Ex. 13.0 at 24. In the event PGL does file a rate case in less than four years, and as explained in Staff’s direct testimony, any unamortized rate case expense from the current case will be included in rate case expense in that future rate case and recovered in future rates. Staff Ex. 9.0 at 23.

Peoples Gas Mr. Zgonc testified that Staff’s rationale “appears to be that it is appropriate to reduce Peoples Gas’ annual recovery of rate case expense going forward because, in his view, Peoples Gas performed better than it should have” and that this rationale “appears to constitute prohibited single-issue or retroactive ratemaking.” NS-PGL Ex. 13.0 at 24-25. Staff states that Peoples Gas did not fairly present Staff’s testimony, which clearly states that its position is based on Peoples Gas’ rate case history. Staff Ex. 1.0 at 14. Staff’s testimony concerning Peoples Gas’ prior rate case expense was to demonstrate the risk to ratepayers for a too short amortization period, versus the Company always being made whole. Id. at 15. Finally, it is Staff’s position that adopting Mr. Mugera’s proposal would not constitute single-issue or retroactive ratemaking.

Staff adds that while the Company’s witness continues to believe that a two-year amortization period is more appropriate, for purposes of narrowing the issues in this case, Peoples Gas agrees in its surrebuttal testimony to Staff’s 4-year amortization period. Staff considers this issue uncontested. NS-PGL Ex. 23.0 at 7. The Commission should adopt Staff’s proposed 4-year amortization period for rate case expense.

c. **CUB/PCR/City’s Position**

CUB/PCR/City supports Staff witness Mugera’s $1.8 million adjustment to PGL’s cost of service to reflect a more reasonable 6-year amortization of rate case expense. Staff Ex. 1.0 at 14-16. For context, CUB/PCR/City note that the Commission approved a 2.5-year amortization period in PGL’s most recent rate case, which was 9 years ago. Docket. Nos. 14-0224/14-0225 (cons.), Order at 99. CUB/PCR/City argue this outcome illustrates the risk of the utility over-recovering by several times the actual amount of its rate case expense if the Commission approves too short an amortization period.

d. **Commission Analysis and Conclusion**

The Companies state that North Shore proposed an amortization period for its rate case expense of two years, and that proposal was not contested. Therefore, the
Commission approves a two-year amortization period for North Shore’s rate case expense.

Staff originally recommended that an average of Peoples Gas’ last three rate cases be used, which resulted in a six-year average amortization period for rate case expense. Staff adjusted its proposed rate case expense amortization to reflect a four-year amortization period for Peoples Gas and the Companies agreed. With the sunset of Rider QIP, the Commission finds it more likely that the Company will be filing another rate case before the six-year period amortization period as supported by CUB/PCR/City. Therefore, the Commission accepts the compromise between Peoples Gas and Staff for a four-year amortization period for rate case expense for Peoples Gas.

2. Rate Case Expense
   a. Companies’ Position

The Companies state that Section 9-229 of the Act requires that the Commission 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.” 220 ILCS 5/9-229. Part 288.40 lists the factors the Commission will consider when making this determination.

North Shore’s filed rate case expense estimate was $3.5 million, and Peoples Gas’ estimate was $5.2 million. NS Ex 2.0 REV at 33, NS Ex. 2.1, Sch. C-10; PGL Ex 2.0 REV at 36, PGL Ex. 2.1, Sch. C-10. The Companies state that they have provided regular updates on these expenses as the case has proceeded, including full billing detail for outside counsel, inter-company expenses attributable to work performed by WEC’s service company, WBS and invoices for expert witnesses and other consultants. NS-PGL. Exs. 13.07 at 24.04 REV; NS-PGL Cross Ex. 21.0.

The Companies assert that they consider certain factors in selecting counsel and technical experts, and the steps they take to ensure that rate case expenses incurred for their services are just and reasonable. NS Ex. 2.0 REV at 32–34; PGL Ex. 2.0 REV at 35–37. Those factors include: (1) selection of outside counsel and expert resources with extensive experience both in Illinois rate cases and related proceedings generally and with [the Companies] specifically; (2) negotiation of appropriate estimated hours of work that will be reasonable for the scope of and matters reasonably expected to be involved in this rate case, as well as hourly rates that are just and reasonable in light of the market rates for experienced counsel and technical experts in Chicago generally and for practice before the Commission in Chicago specifically; (3) cost effective use of [WBS] to provide rate case support services; and (4) [staffing the case appropriately to handle] the extensive procedures involved in prosecuting a rate case after filing, which include: the discovery process, analyzing Staff and intervenor direct and rebuttal testimony, assisting with preparation of [the Companies’] rebuttal and surrebuttal testimony, evidentiary hearings, post-hearing briefs and reply briefs, analyzing the Administrative Law Judge’s proposed order, briefs and reply briefs on exceptions, preparing for and participating in oral argument, analyzing the Commission’s Final Order, and preparing a compliance filing. NS Ex. 2.0 REV at 32; PGL Ex. 2.0 REV at 35–38. The Companies state that they also adhere to cost control and oversight measures with respect to rate case expenses. See NS Ex. 2.0 REV at 33; PGL Ex. 2.0 REV at 36–37.
As required by Section 288.30(e) of the Code, the Companies filed a verification by Koby Bailey, Senior Corporate Counsel for Regulatory Affairs at WEC, affirming that the compensation paid or to be paid to outside counsel and experts is supported by billings that are true and accurate; that the costs were reasonable to prepare and litigate the rate case; that the bills were reviewed and approved by utility management prior to payment; and that the bills were not duplicative. NS-PGL Ex. 34.0.

The reasonableness and justness of the Companies' rate case expenses is supported by the factors set forth in Section 288.40 of the Code. North Shore and Peoples Gas have filed all required support for compensation costs as required in Section 288.30. NS Ex. 2.1, Sch. C-10; PGL Ex. 2.1, Sch. C-10; NS-PGL. Exs. 13.07 at 24.04 REV; NS-PGL Cross Ex. 21.0. These exhibits provide all rate case expenses that the Companies have paid to date. This reporting has included invoices that distinguish between services provided by professional and support staff. Id. This rate case has addressed novel and complex issues, as discussed throughout the record. Inside counsel supervised the work of all inside and outside resources to ensure that it was reasonably necessary to prosecute the case, and that the work was relevant to the justness and reasonableness of the proposed utility rates. NS Ex. 2.0 REV at 33; PGL Ex. 2.0 REV at 36–37. With the assistance of their legal department, which regularly hires counsel in multiple jurisdictions and for many types of work, the Companies negotiated estimates of hours, scopes of work, and hourly rates that are just and reasonable in light of market rates for experienced counsel in the Chicago market generally and with experience handling complex Commission proceedings in particular. NS Ex. 2.0 REV at 32; PGL Ex. 2.0 REV at 35–38. Finally, the Companies state that they ensure that the services their counsel provide are not duplicative and that the amount of time taken to perform tasks is reasonable. NS Ex. 2.0 REV at 33; PGL Ex. 2.0 REV at 36–37.

The Companies note that Staff did not take issue with any of the Companies' rate case expenses. The AG, however, challenges these expenses. In her rebuttal testimony, AG witness Selvaggio raised a number of concerns about the Companies' rate case expenses, recommending a test year revenue requirement disallowance of $343,750 for Peoples Gas and $1,400,953 for North Shore. AG Ex. 5.0 at 16; AG Ex. 5.01 NS Sch. A4; AG Ex. 5.01 PGL Sch. A4. The Companies submit that the Commission would be on solid legal ground to simply disregard Ms. Selvaggio's testimony on rate case expense because it was improperly introduced for the first time in rebuttal.

Ms. Selvaggio’s recommended rate case expense disallowances are based entirely on two facts: (1) Peoples Gas and North Shore are using two law firms in their rate cases; and (2) their budgeted rate case expenses are higher on a per-customer basis than other utilities. The Companies argue that all the facts supporting her proposed disallowances have been known since January many months before the AG filed direct testimony, when all of the utilities filed their rate cases. The Companies state that even if for no other reason, Ms. Selvaggio’s testimony should be disregarded because it is untimely. In addition, Ms. Selvaggio argued that North Shore’s rate case expenses (and in particular its outside counsel fees) were unreasonable because they were higher than other Illinois utilities’ on a per-customer basis. AG Ex. 5.0 at 8-12. Ms. Selvaggio recommended a blanket “reasonableness adjustment” to cap North Shore’s rate case expense at $2.09 per customer per year, which is equal to Ameren Gas’ per-customer
cost. *Id.* at 15–16. Ms. Selvaggio also speculated, without providing any evidence, that because North Shore and Peoples Gas are sister utilities, they must be duplicating services. Ms. Selvaggio also criticized the Companies for using two different law firms, took issue with redactions from legal bills intended to protect privileged information from disclosure, and speculated about other aspects of outside counsel fees, concluding that budgeted legal fees attributable to Stephenson Schroeder Ltd. should be disallowed entirely. *Id.* at 12–13. Finally, Ms. Selvaggio criticized the Companies’ use of service company personnel to perform certain rate-case-related tasks, observing that intercompany expense is higher for Peoples Gas and North Shore than for the other gas utilities. *Id.* at 13–15.

The Companies explain that they chose not to contest attorney registration expenses for Quarles & Brady attorneys totaling approximately $3,000. NS-PGL Cross Ex. 16.0. In order to narrow the issues in this case, the Companies agreed to remove these expenses from its revenue requirement. NS-PGL Ex. 24.04 REV. The Companies contest all other aspects of Ms. Selvaggio’s proposed rate case expense disallowance.

As an initial matter, all of Ms. Selvaggio’s concerns are based on budgeted rate case expenses, not actual expenses, which will be the amount recoverable in rates. The Companies argue the amount of rate case expense allowed in the Commission’s Order will be based on near-final actual expense amounts (and projections through the end of the case), pursuant to 83 Ill. Adm. Code 288.110(c) and (e). At the outset of a rate case, there are many unknowns in terms of the issues that may arise, the volume of discovery, and how vehemently Staff and the intervenors will argue over their positions. As a case progresses, the Companies state the scope becomes clearer, and the reality is that Peoples Gas and North Shore are trending well below their filed rate case expense estimates, as demonstrated in NS-PGL Ex. 24.04 REV.

The Companies insist that Ms. Selvaggio has not pointed to a single precedent for her proposal to place a dollars-per-customer cap on North Shore’s rate case expense. In fact, as recently as North Shore’s last rate case, the Commission implicitly rejected just such a cap, holding that “there is a certain amount of work that must be done to prepare for a rate case regardless of the size of the utility.” *N. Shore Gas Co.*, Docket No. 20-0810, Order at 15, (Sept. 8, 2021), (“2021 North Shore Order”). If adopted, Ms. Selvaggio’s proposal would unfairly hamstring smaller utilities in preparing and litigating rate cases. There are major elements in any natural gas rate case that must be addressed irrespective of a utility’s size or customer count. The Companies assert that in utility rate cases—and certainly in this rate case—discovery burdens are significant. The parties served well over 950 discovery requests on North Shore, many of which were complex and contained multiple sub-parts. NS-PGL Ex. 23.0 at 11. Further, there has been a trend toward greater intervenor participation in rate cases in recent years; indeed, there are almost as many intervenors in North Shore’s case as in Peoples Gas’ case. These are just a few examples of the numerous issues that come up in any case, whether for a larger utility or a smaller utility. Adopting a per-customer cap on rate case expense would unreasonably impact small utilities, which have every bit as much right as larger utilities to litigate rate cases and to seek to recover their cost of providing utility service to customers. Therefore, NS and PGL argue Ms. Selvaggio’s per-customer cap on North Shore’s rate case expenses must be rejected.
Further, the Companies contend that Ms. Selvaggio’s speculation that because North Shore and Peoples Gas are sister utilities, they must be duplicating rate case expense is unfounded. While she is correct that there are some common issues in the North Shore and Peoples Gas rate cases, she is completely incorrect—and has failed to introduce any evidence showing—that somehow tasks for Peoples Gas and North Shore are being done twice. Common work supporting the rate cases is done only once and is allocated between the utilities according to a 60/40 ratio that has been in place and approved by the Commission since at least 2006. *Id.* at 12; NS-PGL Ex. 23.02.

Ms. Selvaggio’s argument that Stephenson Schroeder’s fees should be disallowed because Peoples Gas and North Shore have two law firms representing them in the rate case fares no better according to the Companies. It is routine for utilities to hire more than one law firm to work on rate cases—indeed, both Quarles and Jenner & Block worked for North Shore in its 2021 rate case, and Foley & Lardner and Rooney, Rippie & Ratnaswamy worked extensively on the consolidated test year 2015 Peoples Gas/North Shore case. NS-PGL Ex. 23.0 at 12–13. The use of more than one law firm is not limited to Peoples Gas or North Shore; to the contrary, in the past Nicor has used combinations of firms in rate cases. *Id.* at 13. Likewise, ComEd has used combinations of firms in past cases, including Foley & Lardner and Eimer Stahl. *Id.* at 13. The Companies posit that the mere fact that two law firms are working on a proceeding as significant and labor-intensive as this case does not mean that they are duplicating efforts; to the contrary, Quarles and Stephenson Schroeder have distinct—although mutually supporting—roles in the case. *Id.* at 13.

Ms. Selvaggio’s strategic decision to specifically target Stephenson Schroeder’s fees for full disallowance is particularly troubling to the Companies. The Commission has, for several years, emphasized the importance of diversifying utilities’ spending on outside vendors, in particular for professional services. *Id.* at 13. The Companies point out that Stephenson Schroeder is a Women Business Enterprise certified by Illinois’ Commission on Equity and Inclusion. NS-PGL Ex. 23.03. Illinois utilities are of course required to report on their hiring of such vendors annually, so Ms. Selvaggio’s wholesale disallowance of Stephenson Schroeder’s fees would seem to fly directly in the face of formal Commission policy in the Companies’ view. NS-PGL Ex. 23.0 at 13.

Ms. Selvaggio’s ostensible reason for targeting Stephenson Schroeder is that portions of the firm’s bills were redacted. AG Ex. 5.0 at 12–13. However, as Ms. Selvaggio concedes, less-redacted bills were provided, albeit confidentially, following discussions between counsel. *Id.* Moreover, it is entirely routine for utilities to redact portions of their bills that would reveal attorney-client privileged communications. The Companies assert that the proposed disallowance of Stephenson Schroeder’s legal fees should be rejected. NS-PGL Ex. 23.0 at 14.

Additionally, Ms. Selvaggio correctly points out that Peoples Gas and North Shore rely on their service company to provide support for certain aspects of their rate cases, such as rate design, the lead-lag study, and preparation of some rate case schedules. AG Ex. 5.0 at 14–15. She also recognizes that some other utilities use outside consultants like Yardley & Associates and Concentric to perform similar tasks. *Id.* However, the Companies complain that Ms. Selvaggio makes no attempt to explain why one approach is right and the other is wrong, or show that one is more costly than the
nor does she tie this practice to any specific proposed disallowance. The fact of the matter is that different utilities have different approaches to using in-house resources versus consultants for certain aspects of rate cases. It is the Companies position that Ms. Selvaggio has not provided any evidence that Peoples Gas' and North Shore's approach is imprudent or unreasonable.

Finally, in briefing, the AG first points to a handful of discrete outside legal counsel time entries among the thousands in this case that caught Ms. Selvaggio's eye, although the AG does not attempt to quantify or recommend any particular disallowance as a result. AG IB at 60. The Companies state that the time entries and costs she identified were either fully explained as appropriate in response to the discovery requests that the AG cites in its own brief or, in one case, were voluntarily removed from rate case expense. AG IB at 60. These concerns do not warrant any disallowance of rate case expense. Second, the AG argues that costs attributable to the Companies' cost of capital witness was greater than for other utilities, claiming that "NS and PGL paid their ROE consultants a combined $541,000." Id. at 61. The Companies counter this argument, stating the cost that Ms. Selvaggio references is the budgeted cost; the actual cost for the outside expert, the Brattle Group, is on trend to be considerably lower. Therefore, Ms. Selvaggio’s claim that the Companies "paid" Brattle $541,000 is incorrect. Moreover, as Ms. Selvaggio recognizes, the Companies also hired the Brattle Group to provide expert witness testimony from Frank Graves on "Future of Gas" issues, but did not expand the budget for Brattle beyond what was originally anticipated for cost of capital issues alone. AG Ex. 5.0 at 14. For these reasons, the Companies conclude that the AG’s critique of these rate case expenses is baseless and should be rejected. NS-PGL RB at 54–55.

b. Staff’s Position

The Commission should adopt Staff’s recommendations and language for the Final Order with regard to rate case expense. Staff states that North Shore and Peoples Gas have provided documents for the record to support the reasonableness of its rate case expense. Staff Ex. 1.0 at 16. The Companies described their rate case expense within NS Ex. 2.0 REV, 32-34 and NS Ex. 2.1, Sch. C-10 for North Shore and PGL Ex. 2.0 REV, 35-37 and PGL Ex. 2.1, Sch. C-10 for Peoples Gas. The Companies also provided both Public and Confidential and Proprietary versions for North Shore and Peoples Gas Exhibits 2.0 REV and 2.1. Id.

Section 9-229 of the Act requires the Commission to expressly address the justness and reasonableness of the attorney and expert compensation expended by the public utility to prepare and litigate the rate case. 220 ILCS 5/9-229. The Companies have estimated the expenses to prepare and litigate the current rate case to be $3,479,000 for North Shore and $5,213,000 for Peoples. Staff Ex. 1.0 at 17. For North Shore, with a 2-year amortization period, this results in expenses in $1,740,000 the test year revenue requirement. NS Ex. 2.1, Sch. C-10, Column H, Line 16. For Peoples Gas, using Staff’s proposed 4-year amortization period from rebuttal testimony, results in $1,303,250. Staff Sch. 9.10 P. Therefore, Staff proposes that the Final Order in this proceeding include a Commission conclusion as follows:

The Commission has considered the estimated costs to be expended by North Shore and Peoples Gas to compensate
attorneys and technical experts to prepare and litigate rate case proceedings and assesses that the amount included as rate case expense in the revenue requirement of $1,740,000 and $1,303,250 respectively, is just and reasonable pursuant to Section 9-229 of the Act.

If the Commission makes any adjustments to the overall total of rate case expense or amortization period at the conclusion of this proceeding, Staff recommends that those adjustments be reflected in the Commission’s statement that sets forth the amount of rate case expense included in the revenue requirement. Staff Ex. 1.0 at 17.

c. AG’s Position

The AG argues that North Shore and Peoples Gas did not provide sufficient detail or evidence to support their combined $8.7 million rate case expense. The AG asks the Commission to adopt the recommendation of Ms. Selvaggio and reduce North Shore’s rate case expense by $1.401 million and PGL’s rate case expense by $0.172 million because the Companies offer no justifiable explanation for duplicative expenses and high legal fees. Id. In response, the Companies generally complain that their rate case expenses are reasonable because the Companies filed “all required support for compensation costs” and because Senior Corporate Counsel for Regulatory Affairs at WEC, Koby Bailey, affirmed “that the compensation paid or to be paid to outside counsel and experts is supported by billings that are true and accurate; that the costs were reasonable to prepare and litigate the rate case; the bills were reviewed and approved by utility management prior to payment; and that the bills were not duplicative.” NS/PGL IB at 120. The AG notes Mr. Bailey declined to address the facts highlighted by Ms. Selvaggio in making his conclusory assertion that the billings were reasonable.

AG witness Selvaggio found that the Companies’ total rate case expense exceeds the rate case expense requested by all major utilities that filed rate increase requests in 2023, despite Peoples Gas and North Shore having fewer customers than all other utilities except for Ameren’s gas operations. AG Ex. 5.00 at 8. She also highlighted that PGL and NS’s combined rate case expense of $8.7 million is more than $2.5 million higher than Commonwealth Edison’s rate case expense even though ComEd has 3 million more customers than PGL and NS—combined. Id. As a result, she found that NS and PGL’s combined rate case expense makes up a greater percentage of their requested rate increase than any of the other utilities, and that their customers pay a higher average annual cost per customer than the other utilities. AG IB at 59, citing AG Ex. 5.00 at 8–9. The AG maintains that it is unreasonable for Peoples Gas and North Shore’s customers to be stuck with such high expenses when the Companies filed consolidated cases with joint rebuttal and surrebuttal testimony and briefs, and Staff and intervenor witnesses similarly filed consolidated testimony and briefs.

Further, Ms. Selvaggio found that NS and PGL’s legal fees were projected to be half of their respective rate case expenses. AG Ex. 5.00 at 11. She indicated these fees are a higher percentage of the rate case expense than that proposed by any other utility with an ongoing rate case—except for Ameren Illinois Electric’s legal fees for its Multi-Year Rate Plan (“MYRP”). Id. at 11–12. However, while Ameren’s MYRP represents its first Multi-Year Integrated Grid Plan and the first Multi-Year Rate Plan, each with four test
years, Peoples Gas and North Shore presented traditional rate cases that do not include novel or unprecedented issues like those being addressed in Ameren’s MYRP case. *Id.* Further, North Shore and Peoples Gas are the only two companies to include legal costs for two separate law firms, Stephenson Schroeder LTD and Quarles & Brady LLP, in their rate case expense. *Id.* at 12.

According to Ms. Selvaggio, her review of law firm invoices found that certain costs may have been attributable to cases other than this proceeding, outside the scope of representation agreements, for activities that may duplicate the tasks of other internal and external attorneys and Company representatives, and identified as coordination of filings with other gas utilities. AG Ex. 5.00 at 13. While Ms. Stephenson Schroeder spent nearly nine years as General Counsel/Chief Ethics and Compliance Officer of the Commission, and Mr. Casey spent three years in the same position and worked as an Administrative Law Judge with the Commission for four years, they did not make any substantive filings in this docket. NS-PGL Cross Ex. 10.0 at 1–2 (Response to DR AG-NS 10.03). The Companies allege that Stephenson Schroeder provided “complementary services” to those provided by Quarles & Brady, but the record offers no evidence of what they did, why NS and PGL needed to hire two separate law firms in this proceeding, or how those services provided by Stephenson Schroeder were distinct or justified in amount. Ms. Selvaggio thus recommended the Commission remove $0.331 million for North Shore and $0.688 million for Peoples Gas for the costs of Stephenson Schroeder LTD.

The Companies argue that the Commission should reject Ms. Selvaggio’s recommendations because “the mere fact that two law firms are working on a proceeding as significant and labor-intensive as this case does not mean that they are duplicating efforts; to the contrary, Quarles and Stephenson Schroeder have distinct—although mutually supporting—roles in the case.” NS/PGL IB at 125. In addition to not describing these purportedly “distinct” roles, the AG iterates that the Companies never directly address Ms. Selvaggio’s findings that certain costs may have been attributable to cases other than this proceeding, outside the scope of representation agreements, for activities that may duplicate the tasks of other internal and external attorneys and Company representatives, and identified as coordination of filings with other gas utilities. See also AG IB at 60.

Rather than addressing these substantive issues raised by the AG, the AG argues the Companies try to sidetrack the Commission, stating “Ms. Selvaggio’s strategic decision to specifically target Stephenson Schroeder’s fees for full disallowance is particularly troubling” because “Stephenson Schroeder is a Women Business Enterprise [“WBE”].” NS/PGL IB at 125. The AG dismisses the Companies’ response as irrelevant and improper. The AG states that Ms. Selvaggio did not target Stephenson Schroeder’s fees because the firm is a WBE, but because of the clear discrepancies outlined above, extraordinarily high legal costs, and the Companies’ failure to justify paying two firms for duplicate or otherwise improper work. She outlined specific, substantive reasons why the rate case expense should be reduced, all of which go unanswered by the Companies. The AG urges the Commission to adopt Ms. Selvaggio’s disallowance of costs for Stephenson Schroeder LTD.

Ms. Selvaggio also found that NS and PGL paid their ROE witnesses significantly more than the consultants in the other ongoing natural gas rate cases. AG Ex. 5.00 at
14–15. NS and PGL paid their ROE consultants a combined $541,000, while Nicor paid its ROE consultants $262,000 and Ameren Gas paid its ROE consultants $141,000. Id. Similarly, NS and PGL paid $2.040 million in intercompany billings, compared to $0 for Nicor gas and $0.406 million for Ameren. Id. While Ms. Selvaggio did not provide specific adjustments for these discrepancies, she proposed an overall reasonableness adjustment to reduce North Shore’s average annual cost in base rates per customer from $10.74 to $2.09, the same as that requested by AIC gas operations in its ongoing rate case. Id. at 15–16. The AG asks the Commission to make this adjustment because while “AIC has about five times as many customers as North Shore, and just slightly less than Peoples Gas, AIC’s gas rate case expense is the highest per customer among the utilities other than [the] Companies and provides a reasonable cost for the customers of North Shore.” Id.

Companies witness Eidukas claimed that he felt comfortable predicting that the rate case expense for each of the Companies will be significantly less than budgeted. NS-PGL Ex. 23.0 at 9–10. However, the AG points out that the Companies never reduced projected rate case expenses in Surrebuttal Testimony. Staff Cross Ex. 1.00. The Companies also state that this adjustment “would unfairly hamstring smaller utilities in preparing and litigating rate cases.” PGL/NS IB at 123. The AG points out that North Shore is not a small utility, independent of the support provided by its large parent company, WEC. It is a subsidiary of the same parent company as PGL, with the same counsel as PGL, participating in a consolidated case with PGL, and operating just miles from PGL’s service territory in the same county and state. The AG’s position in this docket is not, as the Companies misrepresent, that small utilities do not “have every bit as much right as larger utilities to litigate rate cases and to seek to recover their cost of providing utility service to customers.” NS/PGL IB at 124. Instead, the AG argues that it is unreasonable for North Shore’s customers to pay 18.7% of North Shore’s entire rate increase toward its rate case expense when NS and PGL filed consolidated cases with joint rebuttal and surrebuttal testimony and briefs, and Staff and intervenor witnesses similarly filed consolidated testimony and briefs. The AG urges the Commission to adopt its proposed reasonableness adjustment to North Shore’s rate case expense to remove the Companies’ duplicative, inefficient and unnecessary expenses.

Likewise, the AG asks the Commission to advise the Companies that in future cases, they should file as a single entity to avoid duplicating rate case expenses and other such unwarranted expenses or costs. AG Ex. 5.00 at 16. The AG argues that the Companies should consolidate and file as a single entity to avoid duplicating rate case expenses—as they have done in this docket—to reduce the costs of filing separate initial filings, along with other expenses such as contributions to the intervenor compensation fund. Id.

For these reasons, the AG requests the Commission adopt Ms. Selvaggio’s proposed recommendations. Her adjustments reduce North Shore’s rate case expense by $1.401 million and PGL’s rate case expense by $0.344, as shown on AG IB Attach., Sch. A4.
Section 9-229 of the Act requires the Commission to determine the just and reasonableness of public utility rate case expenses. Staff states North Shore and Peoples Gas have provided documents for the record to support the reasonableness of its rate case expense. The Companies described their rate case expenses and provided public, confidential, and proprietary versions of invoices. See NS-PGL Ex. 23.0. Staff reviewed the documents and information provided by the Companies and recommends that the Commission approve the requested rate case expense.

The AG recommends the Commission adjust the rate case expense for both Companies because (1) the Companies’ rate case expense was higher than that of other utilities in ongoing rate cases before the Commission; (2) some legal services may be duplicative; and (3) expert witnesses used by the Companies were more expensive than experts used by other companies. See AG Ex. 5.0. As such, the AG recommends a disallowance of $1.401 million for North Shore and $0.172 million for Peoples Gas.

The Commission agrees with the AG. The record shows that the Companies’ projected rate case expense is significantly higher than expenses similarly situated Illinois utilities seek to recover in rate cases pending before the Commission. See AG Ex. 5.00, at 14. The Commission further agrees that specific examples cited by the AG raise questions regarding duplicative services and the reasonableness of the work performed. The Commission finds it unreasonable for rate case expense to represent 18.7% of North Shore’s proposed rate increase.

The Companies’ rate case expense as filed does not comply with the Commission’s Rules or with Section 9-229 of the Act. Commission Rules require disclosure of certain information upon filing and during discovery to enable the Commission to make an informed finding of justness and reasonableness as prescribed by Section 9-229 of the Act. Specifically, Commission Rules require disclosure of the hourly rate for services, the number of hours worked, and a description of the services provided. 83 Ill. Admin. Code 288.100(a). The Companies’ confidential and propriety rate case expense exhibits are significantly redacted. See NS-PGL Ex. 13.03 CONF. The information redacted in the confidential version of NS-PGL Ex. 13.03 fails to comply with Part 288.100(a). Failure to provide unredacted information as required by Part 288.100(a) severely impacts the Commission’s ability to make an informed finding of justness and reasonableness. The Commission previously found, as affirmed by the appellate court, that failure to provide such information warrants disallowance of the requested rate case expense. See e.g., Commonwealth Edison Co. v. Ill. Commerce Comm’n, 2014 IL App (1st) 130302, P94 (affirming the Commission’s finding that it could not determine just and reasonableness of attorney’s fees because “[t]here was no evidence as to specific amounts in fees, what each amount was for, the amount of time that was expended, the rates charged, or the reasonableness of those rates”).

Should the Companies choose in future rate cases to recover their rate case expenses from ratepayers under Section 9-229 of the Act, the Commission will need more...
information. Redacting basic information even within confidential exhibits limits the Commission’s ability to determine the justness and reasonableness of rate case expense. The Commonwealth Edison court warned against a “business as usual” approach to rate case expense evidence, and the Commission echoes that warning here. Id., at P90. The Commission must be able to consider relevant details related to utility rate case expense, including hourly rates and hours worked on similar topics, as these costs are ultimately paid for by ratepayers. The Commission was unable to do so in these cases. The Commission therefore adopts the AG’s recommendation and reduces North Shore’s rate case expense by $1.401 million and PGL’s rate case expense by $0.172 million.

3. Incentive Compensation

a. Companies’ Position

The Companies state that another significant revenue requirement dispute concerns the Companies’ test year costs of incentive compensation, and specifically the long-term components of the Companies’ executive compensation plans. The total test year amounts for each of these executive incentive compensation components is broken down in Companies witness Olsen’s rebuttal testimony. See NS-PGL Ex. 21.0 at 15.

Both Staff witness Mugera and CUB/PCR/City witness Leyko take issue with allowing rate recovery for any of these executive compensation plans because, in their view, they are tied to “financial performance metrics,” which the Commission has traditionally disfavored.

The Companies assert that the Commission’s historical approach to rate recovery for incentive compensation, and by extension the positions taken by Mr. Mugera and Mr. Leyko, rest on a false dichotomy: that incentive compensation can either benefit customers or benefit shareholders—but not both. In fact, well-designed incentive compensation programs—including individual components of those programs—can and do benefit both customers and investors by aligning their interests. As a result, the Companies argue that if certain incentive components can be shown to benefit customers, it should not be disqualifying that they may also benefit shareholders. The Commission should view the Companies’ incentive compensation plans through that lens, and should also undertake a more granular analysis of individual plan components than Staff and the CUB coalition would have it do.

If the Commission accepts the Companies’ proposed approach, then the amount of recovery for these plans by each Company is outlined by Mr. Olsen in his surrebuttal testimony. See NS-PGL Ex. 32.0 at 8.

The Companies explain that like most businesses, they maintain market-based compensation programs so they can attract and retain a qualified and motivated work force. In order for the Companies to provide the highest level of safe and reliable service to their customers, they must be able to attract, retain, and motivate the talented employees who make it possible to achieve excellent overall utility operations. The Companies compete for quality employees in a market that includes regulated and non-regulated energy companies as well as non-energy firms. The Companies’ goal, therefore, is to pay their employees a total cash compensation package designed to bring employees’ total cash compensation to the market median (i.e., 50th percentile) of total
cash compensation paid to similarly situated employees at comparable energy industry and general industry (non-energy) companies. The market median levels are primarily based on data provided by Willis Towers Watson, an internationally recognized firm that specializes in both compensation and benefits consulting services. NS Ex. 2.0 REV at 52; PGL Ex. 2.0 REV at 56.

The Companies’ market-median total cash compensation package is comprised of both a base salary and an annual incentive target “pay at risk” component that is dependent upon certain operational performance goals being met. The Companies assert that providing incentive pay at target amount is not a “bonus” paid to employees over and above market levels, but a component of total compensation that is set at the market median level. NS Ex. 2.0 REV at 52–53; PGL Ex. 2.0 REV at 56–57.

The Companies’ compensation programs are reviewed at least annually against the competitive data to ensure their compensation programs will attract and retain a quality work force to serve their customers. The Companies contend that their total cash compensation costs are prudent expenditures that allow them to continue to provide service quality at the level their customers expect while maintaining reasonable rates. NS Ex. 2.0 REV at 53; PGL Ex. 2.0 REV at 57. According to research from organizations such as WorldatWork, a global nonprofit organization of compensation professionals, virtually all of the businesses with which the Companies compete for quality employees have moved a portion of their total cash compensation to variable pay through annual incentive programs, also known as “pay at risk.” The Companies submit that their “pay at risk” is an expected component of a total cash compensation package in today’s talent marketplace. NS Ex. 2.0 REV at 53; PGL Ex. 2.0 REV at 57.

The Companies argue that including a “pay at risk” component in the Companies’ total cash compensation package is important for other reasons, too. Doing so enables the Companies to offer competitive compensation packages that incentivize employees to improve service levels and reduce costs that impact the rates paid by customers. The incentive plan design focuses employees on key goals and objectives that benefit customers, as its design measures criteria concentrated on cost containment and operational goals that are aligned with the interests of customers rather than financial measures that might be more aligned with the interests of shareholders. By making a portion of total cash compensation “at risk”, the Companies strengthen the link between pay and performance for their employees, increasing the Companies’ ability to engage and compensate their employees for superior performance. The Companies’ incentive plans are designed to incentivize employees to improve service levels and reduce costs that impact rates so as to directly benefit the Companies’ customers. The Companies assert that if they were to eliminate incentive compensation and use only base pay to compensate their employees at market-median levels, this could reduce the efficiencies that result from the Companies’ ability to engage and incentivize employee accomplishments toward objectives that benefit customers: improved safety, customer satisfaction, and cost-control. Moving incentive pay to base pay could also reduce the Companies’ ability to motivate their employees towards further improvements in these areas, denying customers the benefits they would receive from such improvements. NS Ex. 2.0 REV at 54–55; PGL Ex. 2.0 REV at 58–59.
The Companies state that a utility’s ability to attract and retain a sufficient, qualified, and motivated workforce benefits customers. Attracting and retaining a sufficient, qualified, and motivated workforce ensures there are enough highly proficient employees to perform needed customer work. In addition, customers benefit by the Companies maintaining and improving the productivity and quality of work performed, which reduces overall costs to customers.

Consistent with this philosophy, the Companies expect to offer three incentive compensation plans for executives in 2024: (a) the Short-Term Performance Plan (“STPP”); (b) the Omnibus Stock Incentive Plan (“OSIP”); and (c) the Performance Unit Plan (“PUP”). NS Ex. 2.0 REV at 56; PGL Ex. 2.0 REV at 60.

The Companies elaborate that the STPP applies to executive officers of North Shore and Peoples Gas. It is anticipated that the 2024 plan will apply the same design as the current STPP. For those officers whose positions primarily relate to utility operations in Illinois, the 2024 annual incentive under the STPP will depend on WEC Energy Group’s financial performance against targets for earnings from continuing operations (25% weight) and cash flow (25% weight), as well as targets for the aggregate net income of WEC Energy Group’s Illinois utility operations (50% weight). Awards can be increased or decreased by up to 10% based upon performance in the operational areas of customer satisfaction (5%), safety (2.5%), and supplier diversity (1.25%) for WEC’s Illinois utility operations, as well as workforce diversity (1.25%) for the entire family of WEC companies. NS Ex. 2.0 REV at 56; PGL Ex. 2.0 REV at 60.

The OSIP contains two parts: WEC restricted stock units (“RSUs”) and stock options. The Companies do not expect the metrics in the 2024 OSIP to differ in relevant part from those in the current plan. NS Ex. 2.0 REV at 59; PGL Ex. 2.0 REV at 63. Also, critically, RSUs are not based on any financial metric. RSUs are simply grants of stock made annually to participants, the value of which is based on the share price at the time of grant. RSUs vest in 33.34% increments on the anniversary date of the grant over three years. RSUs make up 15% of the overall long-term package (including options and PUPs), or 43% of the OSIP as PUPs are under a separate plan. NS-PGL Ex. 21.0 at 13.

The award of the other component of the OSIP, stock options, also is not governed by financial performance. According to the Companies, this component consists of options to purchase shares of common stock of the parent company, WEC (set on the grant date). Options vest in their entirety after three years. Options make up about 20% of the overall long-term incentive package (including RSUs and PUPs), or 57% of the OSIP as (again) PUPs are under a separate plan. RSUs and stock options granted under the OSIP are not tied to any financial criteria. There are no “triggers” or “governors” that alter the amount of eligibility, value, or vesting of these awards. NS-PGL Ex. 21.0 at 13.

Lastly, the PUP awards WEC performance stock units to employees based on certain financial criteria. This plan is different from the stock unit component of the OSIP in that awards are determined based upon the value of WEC stock and are also contingent on performance measures established by the WEC Compensation Committee. Such measures may include WEC’s rank with respect to the performance measures related to selected benchmark utilities, attainment of a certain price-to-earnings ratio at the end of a calendar year, or other performance measure(s) established by the
WEC Compensation Committee at the beginning of the performance period. The Companies note that PUP is new to the Companies’ incentive compensation package since the Commission last considered North Shore’s executive incentive compensation on the merits, so the Commission has not had an opportunity to consider it until now. NS Ex. 2.0 REV at 61; PGL Ex. 2.0 REV at 65.

The Companies believe Staff’s and CUB’s opposition to rate recovery for these incentive compensation plans is based on the Commission’s historical approach to rate recovery for executive compensation, which over at least the past two decades has been on sorting incentive compensation into one of two perceived buckets: one for components based on metrics that benefit customers and not shareholders; and the other for components based on metrics that benefit shareholders and not customers. NS-PGL Ex. 21.0 at 4. The Companies would like the Commission to take a closer look at whether the particular metric actually benefits customers in the particular case. Id. at 4–5.

At the same time, the Companies recognize that the Commission has emphasized that incentives “awarded to promote longevity” have been “found to be permissible in the past,” because “employee longevity provides a tangible benefit to ratepayers through reduced expenses and the creation of greater efficiencies in operations due to a more seasoned workforce.” Ameren Ill. Co., Docket No. 20-0308, Order at 60 (Jan. 13, 2021) (“2021 Ameren Order”). That decision cited previous Ameren decisions to the same effect in Docket Nos. 19-0436 and 18-0463. NS-PGL Ex. 21.0 at 5–6. The Companies contend that these decisions recognize the basic principle that incentives promoting longevity can benefit customers, justifying rate recovery for those incentives. If that is the case, then the Companies should likewise have the opportunity to demonstrate that particular incentive compensation components—including those tied to traditionally disfavored “financial metrics”—promote longevity (or, for that matter, some other value that benefits customers). A categorical approach to disallowing incentives tied to financial metrics eliminates that opportunity, and it is not clear why that approach should apply to some utilities and not to others, which would be arbitrary and capricious. NS-PGL Ex. 21.0 at 6.

The Companies respond to Staff’s attempt to distinguish the 2021 Ameren Order because the incentives at issue there were “not awarded based on Ameren’s financial performance or other measures that incentivize decisions that benefit shareholders” (Staff IB at 57), by stating that this is precisely the point with respect to the OSIP: the RSUs and stock options that make up that plan vest solely based on tenure with the Companies, not any financial metrics. So at minimum, there is no basis for the Commission to deny rate recovery for the OSIP. NS-PGL IB at 139–140; NS-PGL RB at 57–58.

NS and PGL note that the Commission has long approved rate recovery of incentive compensation plan metrics that are designed to control or reduce O&M costs. In Consumers Ill. Water Co., a case often cited by the Commission as establishing the standard for recovery of incentive compensation costs, the Commission approved the utility’s recovery incentive compensation expenses, which included a metric for “maintaining or reducing operating costs at or below budgeted levels.” Consumers Ill. Water Co., Docket No. 03-0403, Order at 14-15 (Apr. 13, 2004). The Companies also point to the rate case Peoples Gas filed in 2007, in which the Commission allowed recovery of costs associated with an incentive compensation plan “based on controlling
O&M expenses,” stating that “we consider this as beneficial to ratepayers”. *N. Shore Gas Co. and Peoples Gas Light & Coke Co.*, Docket Nos. 07-0241/0242 (cons.), Order at 66–67 (Feb. 5, 2008). NS Ex. 2.0 REV at 66–67; PGL Ex. 2.0 REV at 71–72. The Commission, when addressing a similar incentive compensation plan design in Peoples Gas’ rate case filed in 2012, approved recovery for the costs of Peoples Gas’ O&M cost-control metric. See *N. Shore Gas Co. and Peoples Gas Light & Coke Co.*, Docket Nos. 12-0511/0512 (cons.), Order at 130 (June 18, 2013). NS Ex. 2.0 REV at 67; PGL Ex. 2.0 REV at 72.

Finally, the Companies observe that in the Companies’ 2015 Rate Case, no parties opposed recovery of the costs of their Non-Executive Incentive Compensation Plan, including the costs associated with their cost control metric, and the Commission approved such recovery. The same was true in North Shore’s 2021 Rate Case. NS Ex. 2.0 REV at 67; PGL Ex. 2.0 REV at 72.

The Companies opine that these two approved bases for rate recovery—enhancing longevity and reducing O&M—leave no doubt that the question of incentive compensation in the revenue requirement is more nuanced than Staff and CUB reveal. The Companies agree with Mr. Mugera and Mr. Leyko that when it comes to incentive compensation, the test for recoverability should be whether the customer benefits. Where the parties part ways is the apparent categorical assumption that incentives linked to financial metrics can never meet that test. The Companies claim that assumption rests on nothing more than tradition and state that the Companies are not aware of any legal or factual basis for that assumption, and in many cases the empirical evidence is to the contrary. NS-PGL Ex. 21.0 at 6–7.

The Companies state that the Companies’ executive incentive plans will simultaneously benefit customers and investors. Contrary to assertions by Staff and the AG, the Companies have provided more tangible evidence of customer benefits than mere broad statements. They argue that they provided workforce data showing that their annual incentive programs are in line with the vast majority of the companies with which Peoples Gas and North Shore compete for employees. NS Ex. 2.0 REV at 53; PGL Ex. 2.0 REV at 57. They also provided three years of actual data demonstrating that between 2019 and 2021, the O&M cost control metric successfully incentivized both Companies’ employees to control operating expenses—resulting in over $70 million in savings for the customers of both utilities. NS Ex. 2.0 REV at 65–66; PGL Ex. 2.0 REV at 70–71.

They state that the cost control metric is not the only incentive metric driving those significant savings. Those savings should also be attributed to financial metrics, for the simple reason that one of the most effective ways to attain those metrics is by reducing the Companies’ controllable O&M. If the Commission agrees that controlling customer costs should be rewarded, then the same should be true of any reasonable incentive that encourages that behavior, even if some of those incentives also benefit shareholders. NS-PGL Ex. 21.0 at 8.

The Companies also provided specific data on how long-term incentives (“LTIs”) enhance retention (i.e., longevity) at the Companies. From 2020 through 2022, the annual average voluntary, non-retirement turnover for the Companies’ Illinois employees eligible for LTIs was 4.6%. This is 40% lower than the 7.5% turnover rate for non-
executive, professional management and supervisory personnel who were ineligible for LTIs over the same period. The Companies also note that exit survey data from 2022 and 2023 for higher-level managers and professionals (non-officers), many of whom are covered under LTIs, show 11% of employees citing compensation as a reason for leaving. By comparison, 17% of all management employees cited pay as a reason for leaving. The Companies aver that these data points reinforce both the importance of competitive compensation generally, and the specific role of LTIs as an effective retention tool for the senior-level management employees who help ensure consistency and efficiency in service delivery. NS-PGL Ex. 21.0 at 8–9.

NS and PGL add that by applying these concrete data and underlying principles to the Companies’ executive incentive compensation plans, it is clear that at least some of the components of each plan qualify for inclusion in the revenue requirement.

First, the STPP is not based entirely on financial metrics. As Mr. Zgonc explained, the STPP is subject to a 10% upward or downward adjustment for non-financial factors of the type for which the Commission traditionally allows recovery: customer satisfaction, safety, and supplier and employee diversity. NS Ex. 2.0 REV at 56; PGL Ex. 2.0 REV at 60. Mr. Mugera proposes restoring this 10% (but no more), whereas Mr. Leyko does not take a position on whether it meets his criteria for recovery in rates. Staff Ex. 9.0 at 21; CUB/PCR/Chicago Ex. 2.0 at 10, n.14.

Moreover, while the STPP’s baseline metrics are all “financial” in some sense, each one is tied to operating performance in a way that incentivizes reducing controllable O&M and thus saving money for customers. To the extent that occurs, earnings from continuing operations, cash flow, and aggregate net income will all be enhanced. NS-PGL Ex. 21.0 at 12. Mr. Leyko takes issue with the fact that 50% of the STPP’s goals “do not specifically relate to retail operations of either of the Companies; rather they are based on WEC’s consolidated performance.” CUB/PCR/Chicago Ex. 2.0 at 11. Here again, the Companies state Mr. Leyko offers a false choice between two extremes. Additionally, Mr. Olsen has clarified that the net income component of the STPP award, which accounts for 50% of the total, is calibrated to the jurisdiction where the participating officers are serving—meaning that for the participating Illinois officers, the net income component directly reflects Illinois utility O&M and is not impacted by the O&M results of other WEC utilities. NS-PGL Ex. 32.0 at 4. In light of this direct (and unrebutted) relationship between the net income component of STPP and O&M savings at Peoples Gas and North Shore, the Companies argue the Commission should at least allow rate recovery of 50% of the STPP cost in the 2024 test year. Id. at 4.

Turning to the OSIP, neither the RSUs nor the stock options that make up this plan are governed by financial performance; both are purely a function of continued employment with the Companies. NS-PGL Ex. 21.0 at 13. The Companies contend that makes the OSIP just like the RSUs recently approved for recovery by both Nicor (see, e.g., Docket No. 18-1775, Order at 82 (Oct. 2, 2019)) and Ameren Gas (2021 Ameren Order at 60) on the basis that stock units like these that vest over a defined period based solely on continued employment, not subject to or based on financial metrics, provide tangible benefits to ratepayers through reduced expenses and creation of greater efficiencies in operations due to the retention of a more seasoned workforce. The Companies’ RSUs and stock options work the same way, so recovery of the costs for the
Companies’ OSIP should be allowed, as well. NS-PGL Ex. 21.0 at 14; see also NS-PGL Ex. 32.0 at 4–5 (confirming that the Companies expect the 2024 vesting criteria for both components of the OSIP are “purely time-based,” notwithstanding that the OSIP overview (NS-PGL Ex. 2.4) indicates that the WEC Compensation Committee could select other triggers).

The Companies note that Mr. Leyko “acknowledge[s] the Commission has allowed recovery of RSUs in the past for other utilities,” and he even agrees that “it is reasonable to consider the ratemaking treatment for these incentives separately,” because they are “generally understood as stock that is awarded over time based only on continued employment.” CUB/PCR/COC Ex. 4.0 at 5. Based on these points, the Commission should afford the same treatment for the Companies’ OSIP, which consists solely of time-based RSUs and stock options.

The Companies state that, other than confusion over the vesting criteria, CUB offers only one argument to the contrary: that the purpose of the OSIP as described in the OSIP overview (NS-PGL Ex. 2.4) refers in part to “strengthening the mutuality of interest between [employees] and the company’s stockholders”—which Mr. Leyko says shows “the primary purpose of OSIP is to promote shareholder interest.” CUB/PCR/COC Ex. 4.0 at 6–7. The Companies assert that there is no basis to exclude any of the OSIP costs from the revenue requirement. First, the same description also refers to “attracting, retaining and rewarding such individuals,” a priority it places ahead of mutuality of interest with stockholders. So it is not accurate to characterize shareholder interest as the “primary purpose” of the OSIP. Second, if Mr. Leyko agrees that RSUs appropriately incentivize longevity such that their costs are recoverable in rates, the fact that RSUs may also advance shareholder interests should not be disqualifying. NS-PGL Ex. 32.0 at 6.

As for the PUP, in contrast to Staff’s and CUB’s categorical approach, the Companies do not take the position that O&M is the sole driver of the PUP or that 100% of the PUP’s cost should be recovered on that basis. Rather, the Companies’ position is that at least 33% of PUP costs should be included in the revenue requirement given the partial but significant relationship between the PUP’s metrics and controllable O&M. NS-PGL Ex. 32.0 at 7–8.

The Companies argue that at a minimum, the Commission should reject Mr. Mugera’s and Mr. Leyko’s proposed adjustment removing 100% of these incentive costs from the revenue requirement to the extent the Companies have demonstrated these incentive plans are not based purely on financial metrics. Id. at 15.

More importantly, the relevant question should not be whether these programs’ metrics are labeled “financial” or otherwise, or whether shareholders may also benefit from these metrics; it should be whether these metrics deliver benefits for customers, period. At Peoples Gas and North Shore, the controllable O&M savings driven by these metrics are significant: over $70 million in five years, net of STPP, OSIP, and PUP costs. That is before accounting for any other benefits, including the employee longevity fostered by all three plans—the same longevity the Commission found benefited customers and thus justified recovery in Ameren’s recent rate cases. NS-PGL Ex. 21.0 at 15–16. The Companies reiterate that they are only asking the Commission to take a fresh look and reach the same conclusion here. The Companies—unlike Staff, CUB/PCR/City—are not
asking the Commission to take an all-or-nothing approach to this issue. Instead, while rate recovery for all of the Companies’ LTI costs would be justified for the reasons stated in Mr. Olsen’s rebuttal and surrebuttal testimony, and are included in NS-PGL Ex. 24.01 accordingly, the Companies should be allowed to recover at least 50% of STPP costs, 100% of OSIP costs, and 33% of PUP costs for Peoples Gas and North Shore (as well as 100% of the Non-Executive Incentive Plan cost, which is uncontested).

b. **Staff’s Position**

The Commission should adopt Staff’s recommendations regarding incentive compensation and follow its long-standing practice of denying the recovery of incentive compensation costs that are based upon financial metrics and adopt Staff’s adjustments.

In direct testimony, Staff proposed adjustments to reduce each Company’s operating expenses and rate base for incentive compensation cost amounts which are based on financial metrics and do not provide ratepayer benefits, such as specific dollar savings or other tangible benefits. Staff Ex. 1.0 at 7. The Commission requires a showing of benefits to ratepayers for incentive compensation costs to be a recoverable expense. *Id.*

In various rate cases including the Companies’ rate case, Docket Nos. 11-0280/11-0281 (cons.), the Commission concluded that incentive compensation costs are recoverable in rates only if the utility demonstrates tangible benefits to ratepayers. *See N. Shore Gas Co. and Peoples Gas Light & Coke Co.,* Docket Nos. 11-0280/11-0281 (cons.), Order at 54 (Jan. 10, 2012) (“2011 Rate Cases”).

In the Companies’ rate case, Docket Nos. 09-0166/09-0167 (cons.) (“2009 Rate Cases”), the Commission concluded that incentive compensation costs are recoverable in rates only if the utility demonstrates tangible benefits to ratepayers. *See N. Shore Gas Co. and Peoples Gas Light & Coke Co.,* Docket Nos. 09-0166/09-0167 (cons.), Order at 58 (Jan. 21, 2010) (“2009 Rate Cases”). Specifically, the Commission denied cost recovery of the Short-Term Incentive Compensation, Affiliate Charges, and Restricted Stock & Performance Shares plans because the Companies failed to demonstrate direct ratepayer benefit. Similar findings were also made in the Companies’ 2007 rate case concerning incentive compensation costs. *N. Shore Gas Co. and Peoples Gas Light & Coke Co.,* Docket Nos. 07-0241/07-0242 (cons.), Order at 66-67 (Feb. 5, 2008) (“2007 Rate Cases”).

The Companies have not demonstrated in evidence that there are tangible ratepayer benefits as a result of incentive compensation costs associated with financial metrics. Staff notes that the Companies make only general statements to support their position. The Commission, however, according to Staff has not found such general assertions to be sufficient evidence in the past, as demonstrated by the following Commission finding:

A vague allegation that ratepayers benefit from an incentive compensation program is insufficient to demonstrate savings or benefits and thereby justify recovery of costs from ratepayers. *N. Ill. Gas Co.,* Docket No. 04-0779, Order at 44 (Sept. 20, 2005); Staff Ex. 1.0 at 10-11.

The Commission has been very clear and consistent in disallowing incentive compensation costs based upon financial metrics. Staff Ex. 1.0 at 12. Similar contested adjustments to remove incentive compensation based upon financial metrics were adopted by the Commission in the Companies' 2007, 2009 and 2011 Rate Cases. The Companies did not object to adjustments in the 2012 and 2014 rate cases, nor in the Docket No. 20-0810 rate case for North Shore. *N. Shore Gas Co. and Peoples Gas Light & Coke Co.*, Docket Nos. 11-0280/11-0281 (cons.), Order at 47 (Jan. 10, 2012); Docket Nos. 14-0224/14-0225 (cons.), Order at 49-50; and *N. Shore Gas Co.*, Docket No. 20-0810, Order at 8-9 (Sept. 8, 2021), respectively; Staff Ex. 1.0 at 12-13.

The Companies state its proposal is "consistent with the Commission's treatment of Ameren Illinois’s executive short-term incentives" in Docket No. 20-0308. NS Ex. 2.0 REV at 59; PGL Ex. 2.0 REV at 63. Staff disagrees. The AG proposal in the Ameren Illinois case concerns executive compensation for Ameren’s five highest paid officers. Staff Ex. 1.0 at 13.

The AG states that it proposes a $1.658 million reduction of the Company’s projected 2021 executive compensation allocated to gas jurisdictional officers which would result in keeping compensation levels at actual levels from 2019 and would remove executive compensation costs for the Company’s five (5) highest paid officers.

[...]

The AG next argues that the Commission should adopt their proposal to exclude executive compensation for the Company’s five highest paid officers because Ameren has not provided sufficient evidence to explain why its executives should receive such significant increases, or data to indicate whether its proposed level of increase is the least amount ratepayers should pay.

The facts in the Companies’ instant incentive compensation requests are different. Staff Ex. 1.0 at 13. Staff does not agree with the Company that the Order in the Ameren docket, Docket No. 20-0308, provides for the recovery of incentive compensation based upon financial metrics. Staff argued in the Ameren case that Ameren’s proposal was not awarded based on Ameren’s financial performance or other measures that incentivize decisions that benefit shareholders. *Ameren Ill. Co.*, Docket No. 20-0308, Order at 111 (Jan. 13, 2021). The Commission agreed with Staff. *See Id.* at 114
Staff recommends the Commission follow its long-standing practice of denying the recovery of incentive compensation costs that are based upon financial metrics and adopt its adjustments.

In rebuttal testimony, Staff made two updates to: (1) exclude previous disallowances based on the Companies update to remove such amounts from the rate base NS-PGL EX. 13.0 at 32, and (2) exclude the portion of non-financial metrics included in the Short-Term Performance Plan (“STPP”) expense associated with the adjustment. Staff Ex. 9.0 at 20.

To narrow the issues in this proceeding, the Companies offered a ratemaking adjustment to remove these capitalized incentive costs from rate base. This reduces the test year 2024 revenue requirement by $0.9 million for North Shore and by $1.26 million for Peoples Gas. Id. at 20-21.

Staff made an update to its adjustment to incentive compensation related to STPP. Staff’s adjustment was made in response to the rebuttal testimony of Companies witness Olsen that states, “the STPP is subject to a 10% upward or downward adjustments for non-financial factors.” NS-PGL Ex. 21 at 12; Staff Ex. 9.0 at 21. Staff’s adjustment acknowledges and removes the 10% non-financial metrics goals in the STPP from disallowance. Staff Ex. 9.0 at 21.

The Companies state that they provided workforce data showing that their programs are in line with companies that Peoples Gas and North Shore compete with for employees and three years of actual data demonstrating that between 2019 and 2021 the O&M cost control metric successfully incentivized employees to control operating expenses “to the tune of over $70 million in savings for customers of both utilities.” Id. Staff asserts that this argument is a red herring, as O&M cost control metrics are not the source of Staff’s proposed adjustments—rather, it is the Companies’ financial metrics including Earnings per Share. The Companies have failed to provide evidence of the financial metrics own merits of costs savings to ratepayers rather than indirectly through O&M cost control metrics.

The Companies argue that they should have the opportunity to show that particular compensation components, including those tied to “traditionally disfavored ‘financial metrics’” have a value to customers, and would like the Commission to take a “fresh look” at the issue. NS-PGL IB at 134,141. Again, the Commission has been extremely clear about its position regarding incentive compensation based on financial metrics. The utility bears the burden to establish that tangible benefits accrue to ratepayers, in order to prove that the recovery of incentive compensation costs is just and reasonable. Staff IB at 53, citing 220 ILCS 9201(c); N. Shore Gas Co. and Peoples Gas Light & Coke Co., Docket Nos. 09-0166/09-0167 (cons.), Order at 58 (Jan. 21, 2010) (“2009 Rate Cases”). Here, despite their assertions otherwise, the Companies have failed to meet their burden. Staff RB at 26.

The Companies have failed to provide any evidence of savings or benefits beyond a vague allegation of such. Id. The Commission should follow its long-standing practice of denying the recovery of incentive compensation costs that are based upon financial metrics and adopt Staff’s adjustments as reflected on Schedule 9.09 N and P.
c. **AG’s Position**

The AG asks the Commission to reject the Companies’ request to include expenses related to incentive compensation based on financial metrics in its revenue requirement because these metrics primarily benefit shareholders, not ratepayers. The AG requests the Commission adopt the recommendations of Staff witness Mugera and CUB/PCR/City witness Leyko, and remove $7.8 million in incentive compensation based on financial metrics from PGL’s expenses and $892,000 from North Shore’s expenses. See Staff Ex. 9.09 N, 9.09 P.

In response, the Companies argue generally that the Commission should disregard its historical practice of disallowing incentive compensation based on financial metrics and approve the Companies proposals. NS/PGL IB at 126–142. In effect, the Companies argue the Commission should ignore its determination for over the last 20 years. During that time, the Commission has held that incentive compensation expenses based on financial metrics are not recoverable from ratepayers because these metrics do not provide net tangible benefits to ratepayers. The AG argues the Commission should reach the same conclusion in this proceeding.

All else being equal, higher rates generate higher revenues, which in turn generate higher earnings for the Company. Therefore, the AG asserts that including incentive compensation for increased revenue in the revenue requirement would effectively require ratepayers to reward utility management for charging them higher rates. The AG points out that ratepayers also lose if service quality declines in an effort to increase shareholder earnings. Equally unreasonable and illogical is that these incentive costs would be built into rates and collected from ratepayers, regardless of whether the Companies actually hit their targets and are required to pay the reward to employees. Since shareholders are the beneficiaries of the attainment of financial goals, the AG contends that shareholders—not ratepayers—should bear the costs of the incentive compensation related to the achievement of these goals.

For these reasons, the AG asks the Commission to reject the Companies’ attempt to charge consumers for incentive compensation based on financial metrics. These adjustments are shown on Staff Ex. 9.09 N and 9.09 P.

**d. CUB/PCR/City’s Position**

CUB/PCR/City recommend that the Commission remove from cost of service for PGL and NSG approximately $10.1 and $1.1 million, respectively, of incentive compensation tied to corporate financial metrics. CUB/PCR/City Ex. 2.0 at 13.

CUB/PCR/City contend it is well-established in many prior Commission orders that incentive compensation based on financial metrics actually benefits shareholders, not ratepayers. *E.g.*, *N. Ill. Gas Co.*, Docket No. 21-0098, Order at 29 (Nov. 18, 2021). CUB/PCR/City maintain the undisputed beneficiaries of incentive compensation plans tied to financial goals are shareholders. Because incentive compensation program costs tied to financial goals are designed to align the economic interests of shareholders and employees, CUB/PCR/City argue it is shareholders that primarily benefit from these incentive targets. However, shareholders only incur these incentive compensation costs to the extent the employees achieve the incentive compensation financial targets. When
these targets are achieved, the financial performance of the Companies is enhanced, and the cost of the incentive compensation to employees can be paid out of the utility’s enhanced financial results. CUB/PCR/City Ex. 2.0 at 4.

CUB/PCR/City witness Leyko explained if these costs are excluded from the Companies’ costs of service, then shareholders only pay these costs to the extent the incentivized financial performance goals are achieved, and then can pay these costs using the enhanced financial performance of the Companies. Id. at 5. In this regard, CUB/PCR/City argue shareholders are treated fairly because they do not pay incentive compensation costs if the goals are not met, and shareholders only pay the incentive compensation costs to the extent financial performance was enhanced by achievement of the goals. CUB/PCR/City consider shareholders funding employee incentive compensation based on financial metrics to be a win-win for shareholders and employees. Id. at 5-6.

Companies witness Zgonc argues that recovery of incentive compensation costs tied to financial performance promotes attracting and retaining employees and investors. Id. at 3-4. CUB/PCR/City disagree, contending these are benefits to the Companies and their shareholders, not ratepayers, and that this is why the Commission rejected virtually the same arguments in the Companies’ 2012 rate case. See N. Shore Gas Co. and Peoples Gas Light & Coke Co., Docket Nos. 11-0280/11-0281 (cons.), Order at 58-59 (Jan. 10, 2012).

CUB/PCR/City argue the Commission’s findings in the Companies’ prior rate case hold true in this proceeding. CUB/PCR/City contend the Companies have made no credible showing that they have not been able to maintain a stable workforce and provide efficient, safe, and reliable service absent recovery of incentive compensation costs related to financial goals from customers. CUB/PCR/City Ex. 2.0 at 8. CUB/PCR/City argue that because incentive compensation program costs tied to financial goals are designed to align the economic interests of shareholders and employees, it is shareholders that primarily benefit from these incentive targets. Therefore, CUB/PCR/City reason, it is shareholders who should bear the cost of these programs. Id. at 4.

The Companies attempt to defend the recoverability of at least a portion of the disputed bonuses by claiming that its incentive compensation package offers bonuses based on a variety of financial metrics, each of which should be given unique consideration. NS-PGL IB. at 133. Specifically, the Companies cite Commission orders recognizing a ratepayer benefit from incentives promoting longevity and those designed to control or reduce O&M costs. Id. at 133-136. The Companies then claim that the disputed incentive compensation falls into these categories because (1) many other utility companies offer similar compensation packages, (2) O&M costs declined between 2019 and 2021, and (3) companies offering long-term incentives (“LTIs”) tend to have lower turnover than companies that do not. Id. at 136-137. CUB/PCR/City respond that whether other utility companies commonly offer such incentives is immaterial to whether they benefit ratepayers. As for O&M costs, CUB/PCR/City argue the Companies fail to demonstrate how the cited short-term reduction in O&M costs can necessarily be attributed to these incentive compensation packages. CUB/PCR/City elaborate that utilities are far too complex, with far too many factors affecting their O&M costs, to simply
assume that the design of executives’ salary packages is responsible. Further, CUB/PCR/City point out that a 2019 to 2021 fluctuation in O&M expense has a far more obvious potential cause in the COVID-19 pandemic. CUB/PCR/City explain there is no record evidence evaluating the alleged impact of incentive compensation package design or any alternative potential driver of O&M expense movement. In light of this lack of evidence, CUB/PCR/City contend the Commission should dismiss the Companies’ claim as a bald assertion.

In response to the Companies’ claim that LTIs are correlated with greater employee retention, CUB/PCR/City note that LTIs are too broad a category of employee compensation for this data to support the Companies’ specific disputed executive bonuses. CUB/PCR/City state it may be true that companies that offer LTIs tend to retain employees longer than companies that do not, but the Companies made no effort to control for other factors (such as by comparing to a proxy group of similarly situated utility companies) or to target their analysis to incentive compensation tied to financial metrics similar to those the Companies seek to offer at ratepayers’ expense, rather than merely the entire broad category of LTIs. Finally, LTIs, which are long-term incentives, cannot be said to provide a benefit to ratepayers in the Test Year.

Finally, the Companies defend the recoverability of their OSIP and PUP incentive compensation offerings by arguing that they are not based entirely on financial metrics and incorporate some other factors. See NS-PGL IB. at 139-141. For PUP, the Companies argue WEC’s achievement of its authorized return on equity is an example of a metric that reflects ratepayer benefit. Id. at 140-141. CUB/PCR/City retort that the Companies’ corporate parent achieving a targeted rate of return (which will further increase ratepayers’ gas bills beyond that of a sufficient return) provides no benefit to the Companies’ ratepayers. Thus, CUB/PCR/City maintain the Companies fail to demonstrate even that partial recovery of certain specific disputed executive bonus payments should be recovered from ratepayers.

For the reasons set forth above, CUB/PCR/City conclude incentive compensation costs tied to the Companies’ financial performance should not be paid for by its ratepayers because the Companies’ shareholders, and not their ratepayers, are the ones who benefit from improved corporate financial performance. The revenue requirement impact of this disallowance is approximately $10.1 million for Peoples Gas and $1.1 million for North Shore. CUB/PCR/City Ex. 2.0 at 12.

e. Commission Analysis and Conclusion

The Companies argue that the Commission should approve all of the Companies’ incentive compensation costs. The AG, Staff, and CUB/PCR/City are united in their request that the Commission remove the Companies’ incentive compensation costs which are based on financial metrics from the Companies’ recoverable expenses. They reason that the Companies’ financial goals and metrics, such as earnings per share, provide benefits to shareholders but not to ratepayers. The Commission has repeatedly denied the recovery of such incentive compensation based on financial goals.

While the Commission’s past treatment of this issue is not controlling, the Commission must be able to explain a deviation from prior decisions. The proposed incentive compensation may help attract and retain employees as the Companies assert,
but the Companies have failed to show that it will improve operational performance or provide any other tangible benefit to customers beyond a vague allegation of such. There is no evidence that persuades the Commission to depart from its long-held conclusion that incentive compensation based on financial metrics is awarded to increase the Companies’ earnings per share and hit other financial targets, which primarily benefits shareholders. Consistent with past Orders, the Commission disallows the Companies’ incentive compensation costs based on financial metrics.

4. Adjustments to Pension and OBEP Expense for Most Recent Actuarial Reports

In addition to their broader dispute over the appropriate treatment of pension and OPEB balances in rate base, the Companies and Staff had a minor disagreement regarding how to account for the most recent (2023) actuarial reports in the revenue requirement.

In her rebuttal testimony, Staff witness Ebrey proposed an adjustment to reflect the actuarial update, set forth in her Schedules 10.03 N and 10.03 P. The Companies agree with updating the revenue requirement to reflect the actuarial update, but presented certain necessary corrections to Ms. Ebrey’s calculations in their surrebuttal testimony. NS-PGL Ex. 24.0 REV02 at 3, 5–6; NS-PGL Ex. 24.02. In a data request response post-dating surrebuttal testimony, Staff confirmed agreement with several of those corrections, but indicated “further refinement” was necessary to reflect the difference in Staff’s rebuttal schedules versus the Companies’ corrected surrebuttal adjustments. NS-PGL Cross Ex. 4.0.

The Companies have reviewed Staff’s “further refinements” as reflected in NS-PGL Cross Ex. 4.0, Attachs. P and N, and agree with those adjustments. In sum, the Companies agree with Staff’s proposal to implement the latest actuarial update and with Staff’s post-surrebuttal adjustments to the calculation for doing so. NS-PGL IB at 142; NS-PGL RB at 59. This issue is therefore uncontested.

The Commission agrees with the adjustments made between the Companies and Staff and they are approved.

VI. REVENUES

A. Uncontested Issues

1. Forecasted Sales

North Shore customers are currently divided into five service classifications (each referred to as an “S.C.”): i) S.C. No. 1 (“Small Residential Service”); ii) S.C. No. 2 (“General Service”); iii) S.C. No. 4 (“Large Volume Demand Service”); iv) S.C. No. 5 (“Contract Service for Electric Generation”); and v) S.C. No. 7 (“Contract Service to Prevent Bypass”). Each service classification may include retail and transportation customers. Test year forecasts were prepared for S.C. Nos. 1, 2, and 4. Forecasts were not prepared for S.C. Nos. 5 and 7 because they do not have any active customers and are not expected to have any active customers in the test year. NS Ex. 5.0 REV at 2–3; NS-PGL IB at 143.
Peoples Gas customers are currently divided into six service classifications (each also referred to as an “S.C.”): i) S.C. No. 1 (“Small Residential Service”); ii) S.C. No. 2 (“General Service”); iii) S.C. No. 4 (“Large Volume Demand Service”); iv) S.C. No. 5 (“Contract Service for Electric Generation”); v) S.C. No. 7 (“Contract Service to Prevent Bypass”); and vi) S.C. No. 8 (“Compressed Natural Gas Service”). Each service classification may include retail and transportation customers. PGL Ex. 5.0 REV at 2; NS-PGL IB at 143.

To develop the test year sales forecast, both Companies collected the historical and forecasted time-series data used in the forecasting models. This data included service class and individual customer sales, customer counts by service classification, heating degree days, natural gas prices, and economic and demographic estimates. Next, two types of statistical models (average use and number of customers) were developed using the following time-series for S.C. Nos. 1 and 2. Heating and non-heating customers were grouped into separate models. Forecasted sales for S.C. Nos. 1 and 2 were developed by multiplying forecasted average use per customer by forecasted customers. The third step in the process was to forecast sales for S.C. No. 4 (North Shore) and S.C. Nos. 4, 5, 7, and 8 (Peoples Gas) using individual customer data such as historical sales and any customer-specific intelligence. Finally, the service class sales forecasts were evaluated for reasonableness by comparing them to historical weather-normalized sales and customer growth. NS Ex. 5.0 REV at 3; PGL Ex. 5.0 REV at 3; NS-PGL IB at 143–144.

The 2024 test year forecast of total deliveries for North Shore is 36.7 billion cubic feet (“Bcf”). Deliveries to residential and small commercial customers (S.C. Nos. 1 and 2) are forecasted to be 31.6 Bcf. Deliveries to large customers (S.C. No. 4) are forecasted to be 5.1 Bcf. The forecast of total deliveries is 0.7% more than 2021 weather-normalized deliveries, and the forecast of combined deliveries for S.C. Nos. 1 and 2 is 2.1% more than 2021 weather-normalized deliveries. NS Ex. 5.0 REV at 6; NS-PGL IB at 144.

The 2024 test year forecast of total deliveries for Peoples Gas is 169.7 Bcf. Deliveries to residential and small commercial customers (S.C. Nos. 1 and 2) are forecasted to be 144.9 Bcf. Deliveries to large customers (S.C. No. 4, S.C. No. 5, S.C. No. 7, and S.C. No. 8) are forecasted to be 24.8 Bcf. The forecast of total deliveries is 0.8% more than 2021 weather-normalized deliveries, and the forecast of combined deliveries for S.C. Nos. 1 and 2 is 1.2% more than 2021 weather-normalized deliveries. PGL Ex. 5.0 REV at 6; NS-PGL IB at 144. Again, both Companies’ sales forecasts are uncontested.

VII. RATE OF RETURN

A. Contested Issues

1. Capital Structure

   a. Companies’ Position

   PGL’s current authorized common equity ratio is 50.33%; North Shore’s is 51.58%. The Companies propose a common equity ratio of 54.00% in this docket. PGL Ex. 2.0 REV at 53; NS Ex. 2.0 REV at 49. The Companies contend they are proposing increases in the common equity component of their authorized capital structures to support their
investment-grade credit ratings, preserve ready access to capital in all market conditions, and reduce their costs of debt.

The Companies further propose to use the test year period for capital structure which they aver is permitted by the Commission’s rules. 83 Ill. Adm. Code 285.115; see also 2021 North Shore Order at 51 (“a utility could use the test year period for capital structure provided it is reasonable.”). They assert that under Section 9-230 of the Act, the Commission may impute a capital structure that differs from a utility’s forecasted capital structure upon a finding that it would reflect a higher cost of capital caused by the utility’s affiliation with unregulated or non-utility companies. 220 ILCS 5/9-230. The statute does not allow the Commission to reduce the equity in a utility’s capital structure simply for the sake of a lower equity ratio or lower rates. To support an adjustment, there must be a showing of a higher cost of capital caused by such an affiliation. Ill. Bell Tel. Co. v. Ill. Commerce Comm’n, 283 Ill. App. 3d 188, 207 (2d Dist. 1996). The Companies argue the capital structures they propose for the test year are reasonable and do not reflect a higher cost of capital caused by their affiliation with non-utilities.

Staff claims the Commission “has expressed a preference for the use of actual capital structures assuming they are prudent and reasonable. Thus, the burden is on the Companies to demonstrate that their actual 2022 capital structures are imprudent and/or unreasonable.” Staff IB at 65. According to NS and PGL, Staff cites no judicial or Commission precedent for this standard of review for the Companies’ proposed capital structures, and there is none.

Contrary to Staff’s formulation, the Companies state, the governing standards for authorizing utility ratemaking capital structures are those set forth in Sections 9-201(c) and 9-230 of the Act. The Commission must find that a utility’s capital structure is just and reasonable and satisfies Section 9-203’s prohibition against any increased risk or cost due to affiliation with non-utilities. Ill. Bell Tel. Co. v. Ill. Commerce Comm’n, 283 Ill. App. 3d 188, 208 (2d Dist. 1996).

Although the Commission has on past occasion approved capital structures based on the utility’s historical actual capital structure, it has also cautioned that such decisions “should not be seen as an abandonment of prior practices of adopting projected capital structures, when reasonable in light of all factors, nor is it an invitation for utilities to infuse equity into their capital structure for the sole purpose of justifying their proposed common equity.” 2021 Ameren Order at 130. Likewise, the Companies observe that in North Shore’s 2021 test year rate case, the Commission indicated that “a utility could use the test year period for capital structure provided it is reasonable.” 2021 North Shore at 51.

The Companies argue that there is no basis for Staff’s position that the Commission must start with a utility’s actual historical capital structure and deviate from it only upon the utility’s showing that the structure is imprudent or unreasonable. As the Commission alluded to in the recent Ameren case, such a standard would create the perverse incentive for utilities to manipulate their actual common equity ratios before filing rate cases for the purpose of obtaining higher authorized ratios. Instead, as the Commission has stated, the starting point of the analysis in a future test year rate case is whether the utility’s projected capital structure for the test year is reasonable.
CUB/PCR/COC appear to agree, arguing that the authorized capital structure is subject to the “just and reasonable" standard for rates in general.

A modestly higher common equity ratio for the Companies in 2024 is justified by the higher financial risk for utilities in general in NS’s and PGL’s view. Moody’s Investors Service (“Moody's), Standard & Poor’s (“S&P”), and Fitch Ratings (“Fitch”) have revised their 2023 outlook for the regulated gas and electric utilities sector to “negative” and “deteriorating,” respectively, to reflect these developments. PGL Ex. 4.0 REV at 63-64; NS Ex. 4.0 REV at 70; CUB/PCR Ex. 1.0 at 20. S&P maintains a negative outlook on the utility industry, “noting that since downgrades outpaced upgrades for the second consecutive year in 2021, the median investor-owned utility credit rating fell to the ‘BBB' category for the first time.” PGL Ex. 4.0 REV at 64-65; NS Ex. 4.0 REV at 71.

The Companies assert that their proposed 54.00% common equity ratio is only slightly higher than the recent 53.21% average authorized common equity ratio for U.S. gas utilities. NS-PGL Ex. 15.0 at 65, Fig. 7. It is lower than the 55.81% average authorized equity ratio of the gas utility subsidiaries of the holding companies that comprise the proxy group of publicly traded companies the parties used to estimate the Companies’ cost of equity. Id. at 66.

Staff’s proposed capital structures, however, are inconsistent with more recent and accurate data. NS and PGL state that despite the clear evidence of increasing utility financial risk and increased gas utility common equity ratios, Staff proposes lower common equity ratios based on the Companies’ actual year-end capital structures as of December 31, 2022: 50.79% for PGL and 52.58% for NS. Staff Ex. 4.0Cor at 9. In proposing these backward-looking capital structures, Staff witness McNally observed that “one must use judgment to conclude whether or not a capital structure is consistent with a reasonable degree of financial strength.” Id. at 10. To do that, he compared the Companies’ proposed common equity ratios to (1) the 2020-2022 average common equity ratio of the holding companies in the proxy group used to estimate the Companies’ cost of equity (41.56%) and (2) the 2020-2022 average authorized common equity ratios for U.S. gas utilities (51.39%). Id. at 6.

The Companies note that Mr. McNally curiously attacked Companies witness Bulkley’s comparison of the Companies’ forecasted common equity ratios to those of other gas utilities, arguing that the only appropriate comparison is to the equity ratios of the proxy group holding companies. NS and PGL state that Mr. McNally’s opinion does not withstand even casual scrutiny. As Ms. Bulkley pointed out, the reason that the proxy group companies at the holding company level are used to estimate the cost of equity is that the financial information necessary for the estimation is only available at the holding company level and is not available for the gas utility subsidiaries that are most directly comparable to the Companies. NS-PGL Ex. 26.0 at 16. Mr. McNally provided no evidence that the cost of equity estimates for the Companies are higher than they should be by relying on data from a proxy group of companies at the holding company level. In fact, Ms. Bulkley recognized that the publicly traded utility holding companies in the proxy group are not entirely comparable to the Companies and as a result she compared the business risks of the Companies to the gas utility subsidiaries of the publicly traded proxy group holding companies. Staff conducted no such analysis.
Regardless, the Commission has never adopted the policy Mr. McNally proposes. Setting gas utility common equity ratios in the low 40% range would be devastating to the authorized costs of capital of Illinois gas utilities and would trigger negative credit actions. Indeed, such low equity ratios would imply a downgrade of PGL’s Moody’s A2 credit rating to Baa. See Staff Ex. 4.0Cor at 11, Table 1.

Additionally, Mr. McNally’s comparison, relied on book value capital structures of the holding companies, which creates a mismatch with the market value capital structure data that all three analysts in this case relied on to estimate the Companies’ cost of equity with the DCF and CAPM analyses. NS-PGL Ex. 15.0 at 60. The Companies opine that if their common equity ratios were to be set at the higher risk holding company level, their authorized ROEs would need to reflect the higher risk. The fact of the matter is that utility rates of return have been set historically by combining estimates of market cost of holding company-level equity to utility-level capital structures. If Staff is seriously proposing that utility capital structures be based on those of the proxy group holding companies, then NS and PGL believe one of two things must happen. Either the proxy group common equity ratio must be based on market value, or the utility’s ROE must reflect the higher risk of the proxy group’s book value capital structure. Otherwise, the result will be an arbitrary and inappropriate mismatch between risk and cost.

The Companies note that instead of the proxy group holding companies’ capital structures, Mr. McNally supported his proposed common equity ratios precisely the same way Ms. Bulkley (and CUB/PCR/City witness Walters) did, by comparing the Companies’ proposed ratios to the average authorized ratios of other U.S. gas utilities. There is thus agreement among the Companies, Staff, and CUB/PCR/City that recent authorized common equity ratios of other U.S. gas utilities are an appropriate comparative standard. However, the Companies claim that Staff’s data are outdated and inaccurate. More recent and more accurate data provided by the Companies and CUB/PCR/City support the Companies’ forecasted common equity ratio of 54.00%.

The Companies urge the Commission to rely on the most recent and accurate data on other gas utilities’ authorized common equity ratios as the best data to use in evaluating the Utilities’ proposed common equity ratio. Staff Ex. 4.0Cor at 16 (most recent interest rates are best evidence of future interest rates). The Companies’ proposed 54.00% common equity ratios are comparable to the most recent and accurate average authorized gas utility common equity ratios of record, the 53.21% average calculated by Ms. Bulkley and the 54.49% average calculated by Mr. Walters. Based on this agreed standard of comparison, and using the most recent and accurate information available, the Companies’ state their proposed common equity ratio of 54.00% is reasonable, whereas Staff’s lower proposed ratios based on outdated and inaccurate historical data are not.

Ms. Bulkley, in addition to her comparison to recent authorized common equity ratios of U.S. gas utilities in general, also compared the Companies’ proposed common equity ratios to the actual and authorized common equity ratios of a subset of those gas utilities: the actual and authorized common equity ratios of the gas utility subsidiaries of the holding companies that comprised the proxy group. She found the average actual common equity ratio of those gas utilities to be 54.19% and their average authorized common equity ratio to be 55.81%. NS Ex. 4.11 REV; PGL Ex. 4.10 REV; NS-PGL Ex.
15.6. NS and PGL note that both averages are higher than and support the Companies’ proposed 54.00% common equity ratios.

The Companies also note that Staff criticizes this analysis, alleging that Ms. Bulkley inappropriately “created a separate and distinct sample based on the operating subsidiaries of the Proxy Group rather than the Proxy Group itself.” Staff IB at 70. However, that is exactly what Mr. McNally did in comparing his proposed equity ratios to those of the U.S. gas utilities that happened to have rate cases in 2020-2022. Staff also declares Ms. Bulkley’s comparison to the “proxy group” gas utilities invalid because she “did not demonstrate that group of operating subsidiaries to be equivalent in risk to North Shore and Peoples Gas.” Id. at 71. But neither did Mr. McNally demonstrate that his sample of gas utilities—those that had rate cases in 2020-2022—were equivalent in risk.

In any event, it is the Companies’ position that Mr. McNally’s dispute with Ms. Bulkley’s alternative “proxy group” is mooted by the fact that Staff, the Companies and CUB/PCR all rely on recent authorized gas utility equity ratios as a relevant benchmark. And the data from the most reliable of those samples support the Companies’ proposed equity ratios of 54.00%.

The Companies claim that another problem with Staff’s proposed capital structures is that its financial strength analysis is baseless. They explain that Staff also supports its proposed capital structures by comparing “the financial strength implicit in Staff’s proposed revenue requirements (including the proposed capital structures) to Moody’s benchmark ratios for regulated electric and gas utilities” and concludes its proposed revenue requirements “are sufficient to support [the Utilities’] financial strength, which indicates strong financial health.” Staff Ex. 4.0Cor at 10-12. This information is comforting, but it is not germane to the topic at hand because the comparison is not specific to the Companies’ capital structures but is rather based on Staff’s entire revenue requirement. The common equity ratios proposed by both the Companies and Staff fall under Moody’s “A” credit rating category, which Staff considers an indication of “strong financial health” and therefore reasonable. Staff’s analysis fails to establish that the Companies’ proposed capital structures would reflect higher costs of capital caused by affiliation with non-utilities or would be otherwise unreasonable.

Lastly, the Companies take issue with Staff’s allegation that holding companies such as WEC “have an economic incentive to maintain relatively low equity ratios (i.e., high debt levels) at the utility operating company level, because they can borrow at low rates at the holding company level and in turn, invest that capital in the utility where it will earn relatively high equity returns. The utility, in such scenarios, despite being very low risk based solely on its standalone risk, may face a higher level of risk because of its parent’s debt requirements. In this scenario, a utility subsidiary will often be motivated to maintain a higher equity ratio than it requires in order to increase the utility’s allowed rate of return.” Staff IB at 69. NS and PGL respond stating that Staff presented no evidence in this case that the Companies’ proposed capital structure is the result of such manipulation by their holding company. To the contrary, the only evidence in this case of the motivations for the Companies’ proposed 54.00% equity ratios are those stated by Companies witness Zgonc: to support their investment-grade credit ratings, preserve ready access to capital in all market conditions, and reduce their costs of debt. The record
amply supports a Commission finding that the Companies’ proposed capital structures comply with Section 9-230 of the Act.

For these reasons, the Companies conclude that they have proposed reasonable capital structures and their proposed common equity ratios of 54.00% compare favorably with recent authorized common equity ratios of other U.S. gas utilities, which reflect a trend upward as the financial risks for gas utilities have generally risen due to prevailing market conditions. The proposed capital structures will help maintain the Companies’ current investment grade credit ratings and reduce the Companies’ cost of debt. There is no basis in this record for the Commission to impute a different capital structure based on a finding under Section 9-230 Act.

b. Staff’s Position

Staff recommends the Commission adopt the Companies’ actual year-end 2022 capital structures. For North Shore, that would be a capital structure that contains 5.40% short-term debt, 42.02% long-term debt, and 52.58% common equity, as presented on Schedule 4.01N. For Peoples Gas, that would be a capital structure that contains 2.95% short-term debt, 46.26% long-term debt, and 50.79% common equity, as presented on Schedule 4.01P. Staff Ex. 4.0Cor at 9. Staff opposes the Companies’ proposed use of forecasted capital structures with a substantially higher equity ratio of 54.00% for both North Shore and Peoples Gas. Staff cannot support the Companies’ capital structures since they contain an excessive proportion of common equity, which Staff argues is unreasonable and would result in unfair costs to ratepayers if adopted.

Staff adds that the Commission has expressed a preference for the use of actual capital structures, assuming they are prudent and reasonable. Thus, the burden is on the Companies to demonstrate that their actual 2022 capital structures are imprudent and/or unreasonable. Staff argues NS and PGL have not and cannot do so because those capital structures are, in fact, prudent and reasonable, as Staff has demonstrated.

Staff explains that one must use judgment to conclude whether a capital structure is consistent with a reasonable degree of financial strength since establishing a specific capital structure as optimal capital structure for a company is problematic. Staff Ex. 4.0Cor at 10. Staff witness McNally compared Staff’s proposed common equity ratios of 52.58% for North Shore and 50.79% for Peoples Gas to the most recent 3-year average common equity ratio for the Proxy Group and the 3-year average authorized equity ratio for gas distribution utilities across the country. The Proxy Group refers to the six-company proxy sample that both Companies witness Bulkley and Staff witness Kight-Garlisch used to derive their return on equity (“ROE”) estimates. Id. at 6-7. The average common equity ratio for the Proxy Group was only 41.56% from 2020-2022, while the average authorized equity ratio for gas distribution utilities for the years 2020 through 2022 was 51.39%. While Staff’s proposed common equity ratios are substantially higher than the Proxy Group’s 3-year average common equity ratio, they are consistent with those authorized for U.S. gas distribution utilities. Id.

Mr. McNally then compared the financial strength implicit in Staff’s proposed revenue requirements (including the proposed capital structures) to Moody’s benchmark ratios for regulated electric and gas utilities. Staff Ex. 4.0Cor at 10-12. He explained that Moody’s currently assigns Peoples Gas an A2 issuer rating, which Moody’s considers
upper medium grade and subject to low credit risk. Mr. McNally also showed that the Moody’s financial ratios produced by Staff’s revenue requirement proposals imply a credit rating of A2 for both North Shore and Peoples Gas. Staff Ex. 4.0Cor at 11, Table 1 and 2. He testified that this demonstrates that Staff’s revenue requirement recommendations are sufficient to support North Shore’s and Peoples Gas’ financial strength, which indicates strong financial health. Id. at 12.

Staff states the Companies’ proposed capital structures include a significantly higher percentage of common equity than the capital structures of the companies that compose the Proxy Group used to derive the Companies' ROE estimates (as discussed in NS Ex. 4.0 and PGL Ex. 4.0). Staff Ex. 4.0Cor at 6-7. While the Companies propose capital structures including 54.00% common equity, the average common equity ratio for the Proxy Group was only 41.56% from 2020-2022. Staff states that all else equal, it is inappropriate to apply the higher cost of equity derived from a sample with a relatively lower percentage of common equity, implying higher risk, to a capital structure with a much higher percentage of common equity, implying lower risk. To do so would produce an overstated weighted average cost of capital. Id. at 7.

Staff maintains the Companies’ proposed forecasted capital structures also include more equity than the capital structures authorized for gas distribution utilities across the U.S. over the last three years, as reported by S&P Global Capital IQ. Specifically, Mr. McNally testified that the average authorized equity ratio for gas distribution utilities for the years 2020 through 2022 was 51.39%, which is substantially lower than the Companies’ 54.00% proposal. Staff Ex. 4.0Cor, 7.

Staff highlights, that the Companies are entitled only to a return sufficient to maintain their financial integrity and attract capital on reasonable terms. The Commission should approve no higher equity ratio than is necessary and reasonable to support the Companies’ financial strength. Staff avers that the Companies have not provided the evidence required to establish that an equity ratio of 54.00% is necessary to maintain their financial strength. Staff Ex. 4.0Cor at 7-8.

Moreover, Staff notes that the Companies’ corporate parent, WEC is rated Baa1 by Moody’s, which is two notches lower than Peoples Gas’ A2 Moody’s rating. Staff explains that therefore Moody’s considers WEC to have higher risk than the Company’s regulated gas utility operations and a company with less risk can maintain a given credit rating with a lower percentage of equity on its balance sheet than a company with greater risk. Yet, the Companies’ proposed common equity ratio of 54.00% is much higher than its riskier parent company’s, which averaged only 41.93% for 2020 through 2022. Id. at 8.

Staff acknowledges this is a very common arrangement in the relationships between holding companies and their operating company subsidiaries. Staff asserts that non-rate regulated corporations have an economic incentive to maintain relatively low equity ratios (i.e., high debt levels) at the holding company level while maintaining relatively high equity ratios (i.e., low debt levels) at the utility operating company level, because they can borrow at low rates at the holding company and in turn, invest that capital in the utility, where it will earn relatively high equity returns. The utility, in such scenarios, despite being very low risk based solely on its standalone risk, may face a
higher level of risk because of its parent’s debt requirements. In this scenario, a utility subsidiary will often be motivated to maintain a higher equity ratio than it requires in order to increase the utility’s allowed rate of return. *Id.* at 8-9.

Staff observes that in response to its critiques, the Companies argue that: (1) Staff’s proposed equity ratio is not in line with that of the sample that Ms. Bulkley created; (2) Staff’s proposal would create greater leverage, requiring a higher cost of common equity; (3) Staff’s proposal would violate Section 9-230 of the Act; and (4) Staff’s comparisons to the Proxy Group’s average equity ratio and to authorized equity ratios nationwide are flawed because the Proxy Group was affected by Winter Storm URI, and because certain authorized equity ratios should have been omitted. *Staff Ex. 12.0 at 2-3.*

First, Staff notes that Ms. Bulkley’s defense of the Companies’ capital structure proposals, including 54.00% common equity, rests on a comparison to a sample other than the sample of companies she relied on to estimate the Companies’ ROE. As Mr. McNally noted, any analysis of the equity ratio based on a proxy sample should be based on the same proxy sample used to derive the ROE (i.e., the six-company Proxy Group). Staff argues that to do otherwise might violate Section 9-230, which prohibits any increased cost of capital related to a public utility’s affiliation with non-utility companies from inclusion in that utility’s rates (220 ILCS 5/9-230), since utility operating companies often have lower risk (i.e., higher credit ratings and higher equity ratios) than their parents, as is the case with Peoples Gas and WEC. That is, combining the higher ROE of a riskier parent company with the higher equity ratio of the lower risk utility subsidiary company overstates a utility’s cost of capital, in violation of Section 9-230. Ms. Bulkley is attempting to use the leveraged holding company/utility subsidiary arrangement of corporations throughout the country to justify her higher proposed equity ratio of 54.00%.

Nonetheless, based on a comparison to the actual and authorized equity ratios for her alternative sample, which she averages as 54.19% and 55.81%, respectively, Ms. Bulkley claims that Mr. McNally’s equity ratio is too low. *NS-PGL Ex. 15.0 at 60, 66.* However, Staff witness McNally testified that Ms. Bulkley did not demonstrate that group of operating subsidiaries to be equivalent in risk to North Shore and Peoples Gas. In contrast, the comparison Staff witness McNally presented in his direct testimony involves the equity ratio for the Proxy Group that Ms. Bulkley herself concluded to be comparable in risk to North Shore and Peoples Gas, which averaged 43.62% (after adjusting for Winter Storm Uri, as discussed below). Also, Staff points out that the average authorized equity ratio for gas distribution utilities for the years 2020 through 2022 was 51.39% (or 51.74% with Ms. Bulkley’s proposed adjustment). Comparing Staff witness McNally’s proposed equity ratios of 52.58% and 50.79% to those benchmarks indicates that the amount of equity in Staff’s proposed capital structures is quite reasonable. *Id.* at 5.

Second, Staff explains that contrary to the Companies’ claim, its proposal would not necessitate a higher cost of common equity. The Companies’ claim is based on Ms. Bulkley’s assertion that it is not appropriate to compare the proposed equity ratios for the Companies to those of the Proxy Group; if such a comparison is to be made, she claims, market value equity ratios should be used. *NS-PGL Ex. 15.0 at 57.* Ms. Bulkley then notes that as the percentage of debt increases, financial risk increases, requiring a higher return for that additional risk. *NS-PGL Ex. 15.0 at 62-63.* However, Staff states that
financial risk only increases if there is an actual increase in the Company’s contractual
debt obligations. But the debt obligations of a company do not increase simply by viewing
them from a different perspective (i.e., book value basis vs. market value basis), which is
what Ms. Bulkley is contemplating. The intrinsic risk level of a company does not change
simply because the manner in which that risk is measured has changed. Simply put, a
company can have only one level of risk at any point in time. To argue otherwise is to
say an investment in a company can be simultaneously more or less risky than itself,
which Staff says is untrue. Staff Ex. 12.0 at 9-10. The foregoing notwithstanding, Staff
contends that Ms. Bulkley’s argument is moot because she did not, and cannot, establish
that the market value of the Companies’ debt and equity are substantially different from
their corresponding book values. Further, Staff claims this is an unconvincing attempt to
introduce a market-to-book value, or leverage, ROE adjustment argument, which has
been repeatedly rejected by the Commission for good reason. Staff Ex. 12.0 at 6, 10.

Third, with respect to the Companies’ Section 9-230 argument, Staff strongly
disagrees with the Companies’ suggestion that comparing the parties’ proposed capital
structures to those of the Proxy Group would somehow cause the Companies’ costs of
capital to reflect the capital structures, risks, and capital costs of unregulated affiliates, in
violation of Section 9-230. Staff asserts this suggestion is unequivocally false. Section
9-230 relates only to affiliates of the utility itself, not with the companies used to estimate
a utility’s capital costs. Thus, a comparison to the Proxy Group companies, which are not
affiliated with North Shore and Peoples Gas, is in no way a violation of Section 9-230.
Regardless, Staff states that its recommended capital structures for the Companies are
neither based on the Proxy Group capital structures nor the capital structures of any of
North Shore and Peoples Gas’ affiliates, such as WEC. Rather, Staff’s recommended
capital structures are North Shore’s and Peoples Gas’ actual capital structures. Staff
continues that contrary to Ms. Bulkley’s claims, Section 9-230 does not state that rate
making capital structures must be established on a stand-alone basis; rather, it merely
states that no increased cost of capital resulting from a utility’s association with non-utility
affiliates can be reflected in the utility’s rates. Also, Ms. Bulkley concluded that the Proxy
Group is sufficiently similar in risk to North Shore and Peoples Gas to use as the basis
for her recommended ROE. Thus, comparing the Proxy Group companies’ capital
structures to North Shore and Peoples Gas is reasonable, regardless of whether the
Proxy Group companies are subsidiaries or parent companies. Staff Ex. 12.0 at 9.

Fourth, Staff argues that its comparisons to the Proxy Group’s average equity ratio
and to authorized equity ratios support its proposals and demonstrate the Companies’
proposals to be unnecessarily expensive, even if adjusted to address the concerns Ms.
Bulkley expressed. With respect to Winter Storm URI, Staff witness McNally
acknowledged that natural disasters could affect both holding companies and operating
subsidiaries. However, he used a sample and a 3-year average to reduce the effects of
unusual occurrences. He testified that even adjusting to remove the effects of Winter
Storm Uri from the capital structure data does not alter the fact that the equity ratios for
the Proxy Group are substantially lower than the Companies’ equity actual ratios, let alone
the forecasted 54.00% common equity ratios advocated by Ms. Bulkley. Ms. Bulkley
notes that, absent the effects of Winter Storm Uri, which occurred in February 2021,
Atmos Energy’s equity ratio in 2021 and 2022 would be consistent with its 2020 equity
ratio. Similarly, she notes that One Gas’ equity ratio fell substantially in 2021 and 2022.
due to Winter Storm Uri. Thus, to eliminate the effects of Winter Storm Uri, Staff witness McNally substituted the 2020 equity ratio of each company for its 2021 and 2022 equity ratios, which only raises the sample average equity ratio from 41.56% to 43.62%. Staff notes that is still substantially below the 52.58% and 50.79% equity ratios it recommends for North Shore and Peoples Gas, respectively, and certainly does not support the Companies' 54.00% equity ratio proposal. Staff Ex. 12.0 at 3.

With regard to the Companies' argument that certain equity ratios should have been omitted from Staff's comparison to national average of authorized equity ratios, Staff notes that Mr. McNally testified that Ms. Bulkley's modifications produce mean and median authorized equity ratios of less than 52%, which still falls between his proposals for North Shore and Peoples Gas, just as the 51.39% average he originally cited did. In contrast, the Companies’ proposed equity ratios of 54.00% are more than two percentage points higher. Staff argues this only substantiates its conclusion that there is no need for the Companies to increase their equity ratios up to 54.00% from their actual equity ratios of only 50.79% for Peoples Gas and 52.58% for North Shore, much less for the Commission to assume they will do so. Staff Ex. 12.0 at 4.

Staff maintains that the only way Ms. Bulkley could construe her information to support the Companies’ 54.00% common equity proposal in any way was to ignore the measures of central tendency of the group (i.e., mean and median) and look only at the range of outcomes, which stretches all the way from a low of 42.01% to a high of 60.59%. Staff reiterates that its proposals, too, fall well within that range of outcomes, only Staff proposals are closer to the measures of central tendency for the group. According to Staff, this again only substantiates the conclusion that there is no need for the Companies to increase their equity ratios to 54.00%. Id. at 5.

c. AG’s Position

The AG asks the Commission to adopt the CUB/PCR/City overall rate of return proposal, which includes a common equity ratio of 52.58% for NS and 50.79% for PGL, and an ROE of 9.5% for both Companies, resulting in an overall rate of return of 7.03% for NS and 6.88% for PGL. Companies witness Bulkley requested a common equity ratio of 54% for both Companies. PGL Ex. 4.0 Rev at 68, NS Ex. 4.0 Rev at 68. The AG explains that a common equity ratio represents the portion of rate base on which consumers pay an equity cost or profit, compared to lower cost debt. The AG asserts that a higher common equity ratio results in higher costs to consumers.

The AG reiterates that the Companies’ rates are increasingly unaffordable and that it is evidenced by the litany of public comments submitted by ratepayers in this docket. Illinois case law makes clear that “[t]he rate making process … involves a balancing of the investor and the consumer interests.” Ill. Bell Tel. Co., 414 Ill. At 287 (1953) (internal quotations and citations omitted). The AG notes that the Illinois Supreme Court has held that “a just and reasonable rate can never exceed—perhaps can rarely equal—the value of the service to the consumer ….” State Pub. Util. Comm’n ex rel. City of Springfield, 291 Ill. at 216 (1919). Further, it is well settled according to the AG, that “if the rightful expectations of the investor are not compatible with those of the consuming public, it is the latter which must prevail,” Camelot Util., Inc., 51 Ill. App. 3d at 10 (3d Dist. 1977). The AG thus contends that it is unreasonable and unnecessary for PGL and NS to have
an increased common equity ratio when their ratepayers are already struggling to pay their bills and the Companies have not demonstrated that their requests are reasonable.

d. **CUB/PCR/City’s Position**

CUB/PCR/City maintain that the Companies’ proposed ratemaking capital structures in this case are excessively weighted with common equity, resulting in an inflated cost of capital that burdens ratepayers. CUB/PCR/City request that the Commission reject the Companies’ proposed ratemaking capital structures in favor of ratemaking capital structures with a reasonable mix of debt and equity that lowers cost to customers while continuing to support the utilities’ credit rating and financial integrity.

CUB/PCR/City contend the record in this case demonstrates that the Companies’ proposed ratemaking equity ratios of 54% produce an excessive cost of capital and are more expensive than necessary to support their credit rating and financial integrity. CUB/PCR/City ask that the Commission reject the Companies’ proposed capital structures and adopt instead Staff’s recommendation to use the actual year-end 2022 equity ratios: 50.79% for Peoples Gas and 52.58% for North Shore. CUB/PCR/City argue Staff demonstrated that its recommended ratemaking capital structures are adequate to support Peoples Gas’ and North Shore’s credit ratings and financial integrity but at much lower cost than the Companies’ proposals. CUB/PCR/City offer that Staff witness McNally and CUB/PCR/City witness Walters demonstrated that the Companies’ continued financial strength does not require bloated equity ratios.

CUB/PCR/City observe that the Act mandates the Commission to only approve rates that are just and reasonable. 220 ILCS 5/9-101. Accordingly, they urge the Commission to adopt an equity ratio that appropriately balances the Companies’ debt and equity capital, is consistent with the average capital structure that regulatory jurisdictions around the country have authorized, and will not cost customers more than is needed to support the Companies’ financial integrity and access to capital markets. CUB/PCR/City also note that the Appellate Court has been clear that the Act requires an equity ratio that is no higher than necessary to assure the Companies’ financial integrity. They point to *Citizens Utilities Board v. Illinois Commerce Commission* in which the Appellate Court found, “The Commission should disallow recovery of any cost of capital in excess of that reasonably necessary for the provision of services. If a utility has included excessive equity in its capital structure, it has inflated the rate of return and its capital cost.” *Citizens Util. Bd. v. Ill. Commerce Comm’n*, 276 Ill. App. 3d 730, 746 (1995).

It is CUB/PCR/City’s position that the record supports the adoption of the capital structures proposed by Staff. Staff Ex. 4.0Cor at 9. Mr. McNally testified that nothing in the record regarding the Companies’ finances nor the current market trends support common equity ratios greater than the actual ratio present at year-end 2022. Staff Ex. 4.0Cor. Mr. McNally points to the equity ratios of the Proxy Group utilized by the Companies in support of this – while the Companies want the Commission to approve excessive 54% equity ratios even though the average common equity ratio for the Proxy Group was only 41.56%. Id. at 7. Further, the authorized equity ratios for gas utilities across the U.S. over the last three years is 51.39%, which is significantly lower than the requested 54%. Id.
Additionally, CUB/PCR/City emphasize that their witness, Mr. Walters testified that average and median commission-authorized equity ratios around the country have floated between 50% and 52% since 2016. CUB/PCR Ex. 1.0 at 6, 7 Tbl. CCW-2. Meanwhile, credit ratings have improved steadily across the natural gas utility industry since 2009. Id. at 8. In fact, Regulatory Research Associates’ (“RRA”) March 2023 Utility Capital Expenditures Report found that:

- “2023 is anticipated to be a record year of utility industry capital investments,”
- “2023 forecast capital expenditures by the RRA-tracked energy utilities are expected to be the greatest spending magnitude of any year-to-date,”
- “[Capital expenditure] in the years 2024 and 2025 is forecast to expand incrementally each year,” “The nation’s electric, gas and water utilities are investing in infrastructure at record levels,” and
- “Several catalysts are anticipated to impel elevated spending over the next several years.”

Id. at 8-9. CUB/PCR/City assert this upward trend in utility capital expenditures demonstrates how effective utilities have been in attracting capital. Id. at 10, Fig. 2. CUB/PCR/City consider this a strong, stable upward trend in utility capital expenditures that has driven, and is expected to continue to drive, shareholder value, making utility securities a strong, stable investment. They argue utilities’ rate base expenditure growth, and the ensuing growth in shareholder profits, cast serious doubt on any utility company’s claim to need an increased ratemaking equity ratio or return. To the contrary, these data highlight the need for regulators to consider whether currently authorized equity ratios and returns are more costly to ratepayers than is necessary to support a utility’s finances and should be reduced.

CUB/PCR/City argue Mr. Walters’ review of metrics such as price-to-earnings, price-to-cash flow, and market price-to-book ratios also showed a strong current utility security valuation that is robust relative to the last several years. Id. at 11. Further, CUB/PCR/City contend these strong valuations of utility stocks indicate that utilities have access to equity capital under reasonable terms and at lower costs. Id. at 11. CUB/PCR/City note, credit rating outlook analyses from S&P, Moody’s, and Fitch all cite rate affordability as a cause for concern for potential investors in utility securities, underscoring that a business model that depends on forcing customers to shoulder ever-increasing costs is unsustainable. Id. at 18-21.

Mr. Walters also reviewed Federal Reserve and independent analyst outlooks and found a general consensus that inflation, and the Federal Reserve policies aimed at combating it, are expected to level off in the near-term. Id. at 12-18. Mr. Walters found that analyst consensus considers the market impacts of Russia’s invasion of Ukraine to be transitory. Id. at 21-22. Mr. Walters supported this by citing the fact that utilities securities generally, and gas utilities securities specifically, have significantly outperformed the market as measured by the S&P 500 Index (“S&P 500”) since the end of the second quarter of 2021, showing a robust performance since the peak of the COVID-19 pandemic. Id. at 22-23. Taking these factors together, CUB/PCR/City conclude any assertion that the Companies need to increase their capital costs beyond
what the market currently requires, in anticipation of foreseeable future market fluctuations, finds no support in the record.

Instead, CUB/PCR/City argue, the record demonstrates that Staff’s revenue requirement recommendations are sufficient to support North Shore’s and Peoples Gas’ financial strength, which indicates strong financial health. Staff Ex. 4.0 at 12. CUB/PCR/City argue the Companies have not and cannot justify their proposed equity ratios. For the foregoing reasons, CUB/PCR/City recommend that the Commission adopt a 50.79% ratemaking equity ratio for Peoples Gas and a 52.58% ratemaking equity ratio for North Shore, as proposed by Staff. See id. at 9. CUB/PCR/City estimate this adjustment would reduce Peoples Gas’ and North Shore’s revenue requirements by approximately $13.7 million and $381,000, respectively.

e. PIOs’ Position

In light of the affordability impacts of Peoples Gas’ proposals in this rate case, PIO state that they do not support Peoples Gas’ proposed common equity ratio. PIO recommend the Commission adopt a capital structure supported by the record and with a lower common equity ratio.

f. Commission Analysis and Conclusion

The Commission notes that a proper capital structure minimizes the cost of capital while maintaining a utility’s financial integrity. The Companies request a common equity ratio of 54% be approved for both North Shore and Peoples Gas. Staff recommends a common equity ratio of 50.79% for Peoples Gas and 52.58% for North Shore. CUB/PCR/City agree with Staff’s recommended common equity ratio of 50.79% for Peoples Gas and 52.58% for North Shore. The Commission needs to determine whether the Companies’ proposed common equity is more than needed to support the Companies’ financial stability.

Staff determined that the Moody’s financial ratios produced by Staff’s revenue requirement proposals imply a credit rating of A2 for both North Shore and Peoples Gas. The Commission agrees with Staff that Companies witness Bulkley did not demonstrate that group of operating subsidiaries she used to be equivalent in risk to North Shore and Peoples Gas. In contrast, the comparison Staff witness McNally presented in his direct testimony involves the equity ratio for the Proxy Group that Ms. Bulkley herself concluded to be comparable in risk to North Shore and Peoples Gas, which averaged 43.62% (after adjusting for Winter Storm Uri). Also, Staff points out that the average authorized equity ratio for gas distribution utilities for the years 2020 through 2022 was 51.39% (or 51.74% with Ms. Bulkley’s proposed adjustment). Comparing Staff witness McNally’s proposed equity ratios of 52.58% and 50.79% to those benchmarks indicates that the amount of equity in Staff’s proposed capital structures is quite reasonable.

Peoples Gas and North Shore have not shown that a higher equity ratio is needed to support their financial integrity. The Commission finds that Staff’s capital structures more closely reflect the comparable risk for both Peoples Gas and North Shore. Therefore, the Commission adopts, for North Shore, a capital structure that contains 5.40% short-term debt, 42.02% long-term debt, and 52.58% common equity, and for
Peoples Gas, a capital structure that contains 2.95% short-term debt, 46.26% long-term debt, and 50.79% common equity.

2. Cost of Short-Term Debt
   a. Companies’ Position

   The Companies assert that no party challenged the Companies’ proposed short-term debt costs in testimony and at the evidentiary hearings, assuming the Companies proposed capital structure is approved. North Shore forecasts interest on short-term debt at a rate of 6.59%, made up of interest on average debt balances at 5.25% plus interest at 1.34% on approximately $0.2 million in credit facility and rating agency fees. NS Ex. 2.0 REV at 51; NS Ex. 2.3, Sch. D-2. Peoples Gas forecasts interest on short-term debt at a rate of 6.85%, made up of interest on average debt balances at 5.25% plus interest at 1.60% on approximately $1.0 million in credit facility and rating agency fees. PGL Ex. 2.0 REV at 55; PGL Ex. 2.3, Sch. D-2.

   Both Companies’ forecasted short-term debt rates are reasonable according to North Shore and Peoples Gas as they reflect the current federal funds rate range of 4.25% to 4.50%, plus two assumed 25 basis point increases in 2023, plus the historical spread of the Companies’ commercial paper over the federal funds rate of 25 to 50 basis points. NS Ex. 4.0 REV at 74; PGL Ex. 4.0 REV at 67-68.

   The Companies state that in its Initial Brief, Staff categorizes this as a contested issue but Staff then goes on to explain that this “is not actually a short-term debt issue, but a capital structure issue.” Staff IB at 76-78. That is, part of Staff’s calculation depends on the Companies’ underlying capital structure (specifically, the total short-term debt balance for each utility); so long as the Commission approves the Companies’ proposed capital structure, the Companies and Staff do not disagree on what the cost of short-term debt should be. *Id.*; *see also* NS-PGL IB, 147 (same) (“any remaining difference in [Mr. McNally’s] overall short-term debt cost calculations is ultimately attributable to differences in his proposed capital structure”). The Companies note that Staff also discusses at length in its Initial Brief why it generally disfavors using forecasted interest rates, but states this discussion is moot since Staff makes clear that in order to reduce issues it does not contest the Companies’ interest rate estimate for short-term debt in the test year. Based on this, the Companies claim this issue is uncontested between Staff and the Companies.

   The Companies assert that CUB/PCR/City submitted no evidence on this issue, but appear to argue for Staff’s position, apparently without realizing that Staff and the Companies are aligned on this point (assuming the Commission approves the Companies’ proposed capital structure).

   b. Staff’s Position

   Staff proposes a different cost of short-term debt for North Shore and Peoples Gas than the Companies propose. Staff recommends a cost of short-term debt of 6.25% for North Shore and a cost of short-term debt of 6.06% for Peoples Gas. Staff notes the Companies propose costs of short-term debt of 6.59% for North Shore and 6.85% for Peoples Gas, based on projected commercial paper rates for 2024 and credit facility and credit agency fees. Staff Ex. 12.0 at 12.
Staff witness McNally’s cost of short-term debt is based upon two drivers, interest expense and other expenses. For the interest expense portion, Mr. McNally adopted the Companies’ 5.25% interest rate estimate. The Companies’ interest expense estimate of 5.25% is based on a forecast of the Fed Funds rate of 5.00% for the 3rd quarter of 2023 plus a spread of 0.25% to reflect the premium to issue 1-month commercial paper. Like the Companies, Mr. McNally assumed the same interest rate for both Peoples Gas and North Shore, as Peoples Gas lends to North Shore. While Staff would typically rely on current interest rates to estimate the cost of short-term debt for future years, the forecasted rate used by the Companies compares favorably with current interest rates. Thus, to reduce issues, Mr. McNally did not contest the Companies’ interest rate estimate. Id. at 13. However, Staff notes that accurately forecasting the movement of interest rates is problematic and attempts to do so are notoriously inaccurate which is why the Commission has repeatedly rejected the use of forecasted interest rates and, instead, relied on current, observable market interest rates.

For the other expense portion, Staff witness McNally divided the annual dollar value of each Company’s other expense, as indicated in Companies witness Zgonc’s direct testimony, by its respective short-term debt balance. North Shore’s $0.2 million other expense divided by Mr. McNally’s proposed short-term debt balance of $19,997,708 equals 1.00%. Peoples Gas’ $1.0 million other expense divided by Mr. McNally’s proposed short-term debt balance of $124,043,333 equals 0.81%. Adding those costs to the 5.25% interest rate portion produces costs of short-term debt of 6.25% for North Shore and 6.06% for Peoples Gas. Id.

Staff explains that Mr. Zgonc’s estimate differs from Mr. McNally’s estimate primarily because the Companies’ proposed capital structures include less short-term debt than Staff proposes. As such, the credit facility and rating agency expenses, which are fixed (i.e., do not vary with the amount of short-term debt outstanding), represent a greater proportion relative to the Companies’ proposed balances of short-term debt. Mr. McNally explained that despite this appearing as a change to the cost of debt, it is not actually a short-term debt cost issue, but a capital structure issue, as both Mr. Zgonc and Mr. McNally incorporate the recovery of the same amount of other expenses through the cost of capital. Additionally, Mr. McNally noted an error in the Companies’ calculation of Peoples Gas’ cost of short-term debt. Specifically, $1 million divided by the Company’s proposed short-term debt balance of $65,508,203 equals 1.53%, rather than the 1.60% the Companies use. Thus, based on that 1.53%, Staff states Peoples Gas’ cost of short-term debt estimate should only be 6.78%, instead of the 6.85% the Companies present. Id. at 13-14. Staff notes the Company did not rebut this correction.

c. CUB/PCR/City’s Position

CUB/PCR/City support the adoption of Staff witness McNally’s proposed capital structure recommendations and therefore the 6.06% cost of short-term debt for PGL and the rejection of PGL’s proposed 6.85% cost of short-term debt, as well as the adoption of Mr. McNally’s proposed 6.25% cost of short-term debt for NS and the rejection of NS’ proposed 6.59% cost of short-term debt. see Staff Ex. 4.0, Sch. 4.01P; Staff Ex. 4.0 Schedule 4.01N.
d. Commission Analysis and Conclusion

The Commission notes that the use of forecasted averages has been routinely rejected and it has relied on current market rates when setting the cost of short-term debt. However, in this case, Staff testified that the forecasted rate used by the Companies compared favorably with current interest rates, and thus, to reduce issues, Staff did not contest the Companies’ 5.25% interest rate estimate. The Commission finds that the cost of short-term debt is based upon two drivers, interest expense and other expenses. For the other expense portion, the Companies and Staff differ due to the difference in the balances of short-term debt included in the respective capital structure recommendations. Because the Commission adopts Staff’s recommended capital structure, Staff’s estimates for other expenses were added to the 5.25% interest rate portion, which produces costs of short-term debt of 6.25% for North Shore and 6.06% for Peoples Gas.

3. Cost of Long-Term Debt

a. Companies’ Position

North Shore’s overall cost of long-term debt included in the proposed test year cost of capital is 4.23%. NS Ex. 2.0 REV at 51; NS Ex. 2.3, Sch. D-3. Peoples Gas’ overall cost of long-term debt included in the proposed test year cost of capital is 3.77%. PGL Ex. 2.0 REV at 55; PGL Ex. 2.3, Sch. D-3. The Companies explain that both of these amounts reflect the costs of pre-existing or “embedded” long-term debt plus the expected interest (6.05%) on new issuances, as reflected in each Company’s Schedule D-3. The Companies assert that Companies witness Bulkley confirmed that both costs are reasonable. NS Ex. 4.0 REV at 73; PGL Ex. 4.0 REV at 66-67.

According to the Companies, Staff witness McNally derived lower long-term debt costs (4.03% for North Shore, 3.69% for Peoples Gas) based on his assumption that the interest on new issuances will be approximately 100 basis points lower: 5.07%, rather than 6.05%. Staff Ex. 4.0 at 16. Mr. McNally’s estimate is based on the actual A-rated utility long-term bond yield average, as reported by Moody’s, on a single day: April 12, 2023—which is now over five months ago. Id. at 16. The Companies argue it does not account for more recent bond rates or any projection of where those rates are heading, nor does it account for any private placement premium.

By contrast, the Companies state their 6.05% is the sum of the following components: 4.10% reflecting the projected 30-year Treasury yield; 1.10% reflecting the historical spread for A-rated utilities; 0.20% for a private placement premium; a (0.10%) frequent issuer and secured debt discount; and 0.75% to account for the market volatility observed in 2022 and 2023 to date. NS-PGL Ex. 13.0 at 26. This approach better reflects what long-term debt rates will be in the test year, as whatever the rate happened to be on a random date chosen by one individual—in this case, April 12, 2023—has virtually no predictive value for what the rates will be for long-term debt when the Companies’ anticipated issuances occur (October of 2023 and September of 2024). Id. at 26.

Recognizing Staff’s traditional preference for basing long-term debt estimates on historical spot data, Companies witness Zgonc also developed an alternative intended to reduce the inherent arbitrariness of that approach using only historical data. This alternative analysis showed that after accounting for both long-term Treasury yields and
the spread implied by Mr. McNally’s analysis, the range of 10-year Treasury rates from January 1 through May 11, 2023 (a month after the single day Mr. McNally analyzed) yielded an interest rate range of 5.14% to 5.92%, with an average of 5.53%. Id. at 26-27. The Companies state that this does not mean they favor 5.53% over their assumed 6.05%, which they continue to believe is the most reasonable forecast of rates for their long-term issuances in 2023 and 2024. However, if the Commission prefers to base this rate solely on historical data, the alternative approach better accounts for volatility in the 10-year Treasury market, as well as the private placement premium for the Companies’ issuances, and represents a reasonable compromise between the Companies’ and Staff’s positions. Id. at 27. The Companies do not believe Staff substantively responded to Mr. Zgonc’s rebuttal testimony on either point.

Lastly, North Shore and Peoples Gas argue Staff’s position on long-term debt also stands in contrast to its acceptance of the Companies’ forward-looking approach to short-term debt. This appears to be based on Staff’s desire to choose whichever approach results in lower projected costs and it is plainly inconsistent. The Companies state this position is problematic also since Staff did not rebut the Companies’ alternative historical approach, which also supports the Companies’ position.

b. Staff’s Position

Staff disagrees with the Companies’ proposed cost of long-term debt. Staff recommends a cost of long-term debt of 4.03% for North Shore and a cost of long-term debt of 3.69% for Peoples Gas. Staff Ex. 4.0Cor at 16.

Staff’s proposal differs from the Companies due to the interest rate assumed for future debt issuances the Companies forecast. North Shore anticipates a long-term debt issuance in October 2023; Peoples Gas anticipates issuances in October 2023 and September 2024. Staff Ex. 4.0Cor at 16. For each of those issuances, Staff witness McNally applied an interest rate of 5.07%, which is equal to the recent actual A-rated utility long-term bond yield average, as reported by Moody’s. In contrast, the Companies assume an interest rate of 6.05% for each of those issuances, based on a projected interest rate derived from a 30-year U.S. Treasury yield forecast. NS-PGL Ex. 13.0 at 26. As discussed with respect to short-term debt, Staff reiterates the Commission has not historically adopted, nor should it adopt, the use of forecasted interest rates. Staff Ex. 4.0Cor at 16.

Mr. McNally explained the use of recent actual interest rates avoids problematic and unnecessary attempts to predict future interest rates. As noted above, as of April 11, 2023, the actual Moody’s bond yield average for A-rated utilities was 5.07%. Mr. McNally recommended that rate be applied for the proposed new issuances. Substituting 5.07% for the Companies’ 6.05% interest rate estimate for the proposed new issuance produces an overall cost of long-term debt of 4.03% for North Shore, as shown on Schedule 4.02N, and 3.69% for Peoples Gas, as shown on Schedule 4.02P. Id. Staff concludes that the Commission should adopt those costs of long-term debt in this proceeding.

c. CUB/PCR/City’s Position

CUB/PCR/City support the adoption of Staff’s proposed 3.69% cost of long-term debt for Peoples Gas and the rejection of Peoples Gas’ proposed 3.77% cost of long-
term debt, as well as the adoption of Staff’s proposed 4.03% cost of long-term debt for North Shore and the rejection of North Shore’s proposed 4.23% cost of long-term debt. See Staff Ex. 4.0, Sch. 4.01P; Staff Ex. 4.0, Sch. 4.01N.

d. Commission Analysis and Conclusion

The Companies propose for North Shore an overall cost of long-term debt included in the proposed test year cost of capital of 4.23% and for Peoples Gas, the overall cost of long-term debt included in the proposed test year cost of capital is 3.77%. The Companies assume an interest rate of 6.05% for the proposed new issuances, based on a projected interest rate derived from a 30-year U.S. Treasury yield forecast. Staff recommends a cost of long-term debt of 4.03% for North Shore and a cost of long-term debt of 3.69% for Peoples Gas. Staff applied an interest rate of 5.07% to the new proposed issuances, which is equal to the recent actual A-rated utility long-term bond yield average, as reported by Moody’s.

The Commission finds that forecasted debt rates tend to overestimate the cost of debt. The Commission finds that Staff’s estimates for the new issuances are more consistent with market costs. Therefore, Staff’s recommended costs of long-term rates 4.03% for North Shore and 3.69% for Peoples Gas is adopted.

4. Return on Common Equity

a. Companies’ Position

North Shore and People Gas contend that to establish the Companies’ authorized ROE, the Commission is guided by the standards established by the U.S. Supreme Court in its Hope and Bluefield decisions. Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm’n of W.V. (“Bluefield”), 262 U.S. 679 (1923) (“Bluefield”); Fed. Power Comm’n v. Hope Natural Gas Co. (“Hope”), 320 U.S. 591 (1944). They note that the Hope and Bluefield standards include “consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.” PGL Ex. 4.0 REV at 4; NS Ex. 4.0 REV at 4.

The Companies add that the primary tools for estimating a utility’s cost of equity are the various cost of equity estimation models developed by economists for that purpose. Companies witness Bulkley states that “As a practical matter, however, all the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity.” PGL Ex. 4.0 REV at 33; NS Ex. 4.0 REV at 33. Thus, the Companies argue that the consideration of multiple models mitigates at least some of the risk of getting the ROE wrong.

The Commission, the Companies point out, recently recognized that its historical reliance on just two of the models—the Discounted Cash Flow (“DCF”) model and Capital Asset Pricing Model (“CAPM”)—was not sufficient. Recognizing that it “has in the past rejected use of bond yield plus risk premium models as well as the expected earnings analysis,” the Commission “acknowledge[d] that there may be a value in exploring additional models presented by the parties, specifically the Risk Premium and Expected Earnings.” 2019 Nicor Order at 119. North Shore and Peoples Gas assert that the
consideration of additional models brings the Commission’s approach “into closer alignment with how investors inform their investment decisions,” ensures that “the chosen return on equity is based on substantial evidence and does not overvalue any model,” and provides consistency with the methodologies now being followed by other regulatory bodies, including FERC. Id.

According to North Shore and Peoples Gas, the use of multiple analytical approaches to estimate the Companies’ cost of equity is even more important in this case, as market conditions continue to reflect the economy’s rebound from the COVID pandemic. Ms. Bulkley summarized these conditions as follows:

- Inflation is expected to persist over the near-term, which increases the operating risk of the utility during the period in which rates will be in effect.
- Long-term interest rates have increased substantially in the past year and are expected to remain relatively high at least over the next year in response to inflation.
- Since utility dividend yields are now less attractive than the risk-free rates of governmental bonds, and interest rates are expected to remain near current levels over the next year, and since utility stock prices are inversely related to changes in interest rates, it is likely that utility share prices will decline.
- Utility stocks, which have historically been viewed as safe-haven investments in turbulent markets, have experienced volatility that is similar to the overall market in the past nine months, demonstrating an increase in the risk of equity investment in the utility sector.
- Rating agencies have responded to the risks of the utility sector, with [Moody’s] most recently indicating its outlook for the industry in 2023 is “negative,” citing increasing interest rates, inflation and high natural gas prices, all of which create pressures for customer affordability and prompt rate recovery.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of rising interest rates and expect the sector to underperform in the near-term.

PGL Ex. 4.0 REV at 6-7; NS Ex. 4.0 REV at 6-7.

The Companies highlight that in particular interest rates have increased substantially over the past year and are expected to remain elevated as federal monetary policy responds to the highest level of inflation in 40 years. PGL Ex. 4.0 REV at 14-22; NS Ex. 4.0 REV at 14-22. Since PGL’s last rate case for test year 2015, the inflation rate has increased from a minus 0.23% to a positive 7.76%. Id., PGL Ex. 4.0 REV at 28, Fig. 6. Since North Shore’s test year 2021 rate case, the inflation rate has risen from 5.39% to 7.76%. Id., NS Ex. 4.0 REV at 28, Fig. 6. The effect on interest rates has been dramatic, in the Companies’ view, with the yield on the 30-year Treasury bond increasing
from 2.66% in 2015 and 1.92% in 2021 to 4.06% today. *Id.* Additionally, they underscore that, as interest rates rise, utility cost of equity rises. *Id.*, PGL Ex. 4.0 REV at 22-27; NS Ex. 4.0 REV at 22-27.

It is North Shore’s and Peoples Gas’ position that these developments are reflected in the cost of equity estimation models used in this case. In North Shore’s test year 2021 rate case, Staff’s models (DCF and CAPM) generated an average 9.35% cost of equity, compared to 9.89% in this case. *Compare* 2021 North Shore at 72 *with* Staff Ex. 3.0 at 26. Likewise, compared to the 10.00% ROE Ms. Bulkley recommended in North Shore’s 2021 rate case, she finds the Companies’ cost of equity in this case to be in the range of 10.25% to 11.25%. PGL Ex. 4.0 REV at 7; NS Ex. 4.0 REV at 8. CUB/PCR/City’s ROE witness finds the Companies’ cost of equity in this case to be in the range of 9.20% to 9.80%, compared to the 9.10% to 9.50% range calculated by CUB’s ROE witness in the 2021 North Shore case. *Compare* CUB/PCR/City Ex. 1.0 at 3 *with* 2021 North Shore Order at 79.

It stands to reason, the Companies assert, that if the Commission found North Shore’s cost of equity to be 9.67% in 2021, then the Companies’ cost of equity will be higher in 2024. They argue that against this simplified standard, the Companies’ and Staff’s recommended ROEs of 9.90% and 9.83%, respectively, make sense (although, they state that there is no basis for Staff’s 6-basis-point “risk” reduction from Staff’s model-based 9.89% cost of equity). The Companies believe CUB, which would have the Commission set the Companies’ 2024 ROEs to a lower level, at 9.50%, is the outlier.

North Shore and Peoples Gas note that there are sharp distinctions in analytic approaches and outlooks by the three analysts who presented testimony on cost of equity in this proceeding. On behalf of the Companies, Ms. Bulkley used a range of established cost of equity estimation models, including the DCF, CAPM, Empirical CAPM (“ECAPM”) and Bond Yield plus Risk Premium (“BYRP”). Rather than averaging her model results, Ms. Bulkley considered current and near-term future financial market conditions in order to estimate the Companies’ cost of equity for the period when their new rates will be in effect, and concluded that the Companies’ requested ROE of 9.90% is significantly lower than their cost of equity in 2024, which she found to be in the range of 10.25% to 11.25%. PGL Ex. 4.0 REV at 7-8; NS Ex. 4.0 REV at 7-8. The Companies state that with PGL’s current authorized ROE at 9.05% (set in 2015) and NS’s at 9.67% (set in 2021), a 9.90% ROE for each Company would reflect current financial market conditions, including inflation and long-term interest rates, and bring the Companies’ ROEs more in line with the authorized ROEs of other Illinois gas utilities. PGL Ex. 1.0 at 14; NS Ex. 1.0 at 9.

The Companies submit that Staff witness Kight-Garlisch, however, presented only two models, the DCF and CAPM, averaging their results to arrive at a cost of equity of 9.89%. Staff Ex. 3.0 at 26. They complain that consistent with Staff’s formulaic approach to ROE, Ms. Kight-Garlisch did not consider whether the current financial market conditions and data on which her models were based would prevail when the Companies’ rates would be in effect. Instead, based solely on a comparison of credit ratings (assessments of a company’s likelihood of defaulting on its debt and thus the company’s debt cost), Ms. Kight-Garlisch adjusted her ROE recommendation downward by 6 basis points, which represented a different cost of debt between the Companies and the proxy group which resulted in Staff’s ROE recommendation of 9.83%. *Id.* at 26-27.
Lastly, the Companies note that CUB/PCR/City witness Walters proposed an ROE of only 9.50% based on several cost of equity estimation models and a comparison to gas utility authorized ROEs, which he asserts have averaged 9.50% from 2016 to 2023. CUB/PCR/City Ex. 1.0 at 63, 66.

Response to Staff’s Cost of Common Equity Analysis

NS and PGL observe that there is much disagreement between the Companies and Staff on cost of equity estimation methodology. Despite that disagreement, the Companies also observe that Staff’s unadjusted market cost of equity of 9.89% is virtually identical to the Companies’ requested ROE of 9.90%. Because of this similarity, the Companies focus on four issues where they suggest the Commission should address shortcomings and a downward bias in Staff’s ROE methodology. First, the Commission should revisit and reject Staff’s debt risk adjustment to the ROE because there is no evidence that a utility’s cost of equity can be adjusted based on a perceived difference between its cost of debt and the theoretical cost of debt of the proxy group. The Companies explain that debt risk is but one of many factors that affect a utility’s equity risk and cannot alone be the basis for an adjustment to the utility’s cost of equity. Second, the Commission should once again reject Staff’s unexplained case-to-case modification of its DCF methodology, which has no apparent purpose other than to reach a desired (and lower) ROE result. As it did in the 2010 Peoples Gas/North Shore rate case, Staff has employed a different DCF methodology between rate cases with no explanation for why one methodology was appropriate in the first case and another in the second case. See 2010 PGL/NS Order at 124–125. Third, the Commission should, as it did in the 2019 Nicor rate case, reject Staff’s unfounded objections to the BYRP model. See 2019 Nicor Order at 118–119. Fourth, the Commission should revisit and reject Staff’s opposition to the ECAPM in light of conclusive evidence in this record that Staff’s position is baseless. The Companies maintain that Staff’s cost of equity analyses are flawed in a number of other respects, as described in Ms. Bulkley’s testimony.

Debt Risk Adjustment

The Companies explain that when applied to a firm whose stock is not publicly traded, like the Companies, the cost of equity estimation models require the use of data from a compiled group of publicly-traded companies comparable to the firm in “fundamental business and financial respects to serve as its ‘proxy’ in the cost of equity estimation process.” PGL Ex. 4.0 REV at 30; NS Ex. 4.0 REV at 30. For use in this case, Ms. Bulkley compiled a proxy group based on seven screening criteria to evaluate the comparability of the proxy companies to the Companies in terms of business and financial risk. She “developed the screens and thresholds for each screen based on judgment with the intention of balancing the need to maintain a proxy group that is of sufficient size against establishing a proxy group of companies that are comparable in business and financial risk to the Company.” Id., PGL Ex. 4.0 REV at 31; NS Ex. 4.0 REV at 31-32. This proxy group, she concluded, was sufficiently comparable in business and financial risk to estimate the Companies’ cost of equity through the models.

NS and PGL note that the analysts of both Staff and CUB/PCR/City used the same proxy group for their cost of equity estimation models. The Companies assert that Ms. Kight-Garlisch derived the same list of companies to “reflect both the operating and
financial characteristics of the target company,” but without a comprehensive analysis of business and financial risk such as Ms. Bulkley conducted. Staff Ex. 3.0 at 3. Mr. Walters for CUB/PCR/City accepted Ms. Bulkley’s proxy group as one “of similarly situated companies of comparable risk.” CUB/PCR Ex. 1.0 at 31.

After completing her analysis that estimated a market cost of equity of 9.89% for the Companies, Ms. Kight-Garlisch engaged in a limited risk comparison between the proxy group and the Companies, asserting, “If the proxy does not accurately reflect the risk level of the target company, an adjustment should be made to align the cost with the associated risk.” Staff Ex. 3.0 at 26. Comparing the average Moody’s credit rating of the proxy group to PGL’s Moody’s credit rating, she concluded that the Companies had less debt risk than the proxy group and adjusted her recommended ROE downward by 6 basis points, which the Companies indicate represented the difference in the Companies’ cost of debt compared to a hypothetical cost of debt of the proxy group based on its average credit rating.

The Companies acknowledge that this debt risk adjustment has been a component of Staff’s historical ROE methodology. However, they assert that the record in this proceeding demonstrates that this adjustment is devoid of an evidentiary or even theoretical basis. The Companies challenge this adjustment and argue that the conceptual basis for the Staff debt risk adjustment, that hypothetical differences in credit risk and debt cost between the proxy group and the Companies can serve as a basis for an adjustment to their cost of equity, is a fiction. “[C]redit ratings are assessments of the likelihood a company could default on its debt, whereas the topic of the current proceeding is to determine the riskiness and cost of the Company’s equity.” NS-PGL Ex. 15.0 at 32 (emphases in original). “[W]hile credit rating agencies consider the business risks of an individual company when establishing its debt credit rating, they do not conduct a comparative analysis of business risks relative to the proxy group.” Id. at 32. And the Companies assert that Staff did not either.

The Companies maintain that there is simply no evidence that debt risk and cost can be used as a proxy for equity risk and cost such that differentials in debt cost derived from credit rating standards can be used to adjust the cost of equity produced by the cost of equity estimation models. To the contrary, they assert, a utility’s credit rating reflects only its risk of defaulting on its debt obligations. The risk to equity holders is greater and can be incurred even when debt obligations are met.

In focusing solely on debt risk differences, the Companies aver that Ms. Kight-Garlisch performed no comprehensive comparison of business and financial risks to make a conclusion of overall comparability for the purpose of determining the Companies’ cost of equity. In contrast, they state that Ms. Bulkley did so, and concluded that the Companies have slightly greater regulatory and business risk than the proxy group. Ms. Bulkley’s comprehensive analysis for the proxy group and the Companies’ risk included consideration of their respective credit ratings, but also covered capital expenditure requirements, capital tracking and other rate adjustment mechanisms, and regulatory risk. PGL Ex. 4.0 REV at 51-67; NS Ex. 4.0 REV at 51-67. Thus, the Companies argue that even if it had any theoretical basis, Staff’s single-issue risk adjustment is not supported by substantial evidence.
NS and PGL state that Staff’s debt risk adjustment is but one part of the kind of comprehensive business and financial risk comparison between a proxy group and the utility that is relevant to the utility’s cost of equity. A credit rating and debt cost comparison alone proves nothing with respect to the overall comparability of a utility and a proxy group for the purpose of determining the utility’s cost of equity. Accordingly, the Companies urge the Commission to reject Staff’s risk adjustment.

**DCF**

Ms. Bulkley explained that the DCF model “is based on the theory that a stock’s current price represents the present value of all expected future cash flows.” PGL Ex. 4.0 REV at 36; NS Ex. 4.0 REV at 36. The Companies mention that in North Shore’s 2021 Rate Case, Staff’s ROE recommendation was derived from taking the average of the results from Staff’s DCF and CAPM models. 2021 North Shore Order at 67. In that case, Staff utilized the constant growth version of the DCF model. *Id.* at 68.

In this case, the Companies note that Staff relies on two different versions of the DCF model, a constant growth version and a non-constant growth version. North Shore and Peoples Gas take issue with Staff’s use of the non-constant growth version in this case. They assert that there is a theoretical basis for not considering that version of the DCF model in gas utility rate cases. Ms. Bulkley explained, “the utility industry is considered a mature industry due to its regulated status and relatively stable demand,” so there is no basis to assume variable periods of future growth. NS-PGL Ex. 15.0 at 11. Also, the use of the non-constant growth version introduces additional assumptions and potential analyst bias, namely “the duration of the first and second stages of the analysis, and the growth rates for the second and third stages.” *Id.* at 11. The Companies state that while Ms. Kight-Garlisch claimed that “even for mature industries, if analysts’ forecasts are not sustainable for infinity, then they should not be used in a DCF model,” (Staff Ex. 11.0 at 4), she presented no evidence to support her position that it is unreasonable to assume that well established utilities can grow indefinitely at a rate that is greater than the economy over a long term. By contrast, Ms. Bulkley presented evidence that the total factor productivity growth for the utility industry has outpaced the overall economy for at least the last 40 years. NS-PGL Ex. 15.0 at 12-13. However, the Companies point out the fact remains that Staff itself relies on infinite projected growth rates for its constant growth DCF and the market return in its CAPM analysis. *Id.* at 5.

In any event, the Companies argue that Ms. Kight-Garlisch never explained why, if it was appropriate to rely on the non-constant version of the DCF model in this case, it was appropriate for Staff to exclude it in North Shore’s 2021 Rate Case. They speculate that the answer is likely result-driven, noting that if Staff had consistently relied only on its constant growth model in this case, its DCF result would have been 9.40% instead of the 8.81% Staff derives by averaging the results from the two versions, and Staff’s overall cost of equity estimate would have been 10.18% instead of 9.89%. *Id.* at 26. The Companies allege that it appears Staff included a non-constant DCF model in this case to arrive at a lower cost of equity estimate.

Regardless of its purpose, North Shore and Peoples Gas state that Staff’s change in ROE methodology between rate cases is arbitrary and capricious. Staff did the same thing in the 2010 PGL/NS rate cases and the Commission rejected Staff’s non-constant
DCF result. See 2010 NS/PGL at 124–125. Staff used the constant growth version of
the DCF model in the Companies’ prior rate cases, but in the 2010 cases, Staff relied on
results from both versions. Id. According to the Companies, Staff claimed there were
certain instances in which the multistage model is preferable, such as when “the
measurement error associated with the constant growth DCF analysis exceeds that
associated with a non-constant growth DCF model.” Id. at 125. However, the
Commission found the record lacking “a sufficient explanation of what circumstances in the current case would warrant such a preference” and “the reasons for Staff’s switch to the non-constant growth version of the DCF model require additional inquiry.” Id. (emphases added). Thus, the Commission rejected Staff’s non-constant growth DCF result and instead relied on Staff’s constant growth DCF result in its decision-making. Id.

The Companies state that this situation is exactly the same and therefore the
Commission should reject Staff’s non-constant growth DCF result. They maintain that
while Staff describes the theoretical basis for considering the non-constant growth version of the DCF model, Staff has failed to present evidence as to why it should be considered in this case. Moreover, the Companies argue that Staff has failed to explain its switch from relying solely on the constant growth version of the model in the 2021 North Shore case to relying on both versions of the model in this case.

**BYRP**

The Companies state that despite the Commission’s 2019 finding “that there may be a value in exploring additional models presented by the parties, specifically the Risk Premium and Expected Earnings, to bring our methodology into closer alignment with how investors inform their investment decisions” (2019 Nicor Order at 119), Staff still opposes the BYRP model. This model “is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned over bondholders. The Companies explains that in other words, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds.” PGL Ex. 4.0 REV at 47; NS Ex. 4.0 REV at 47.

In her BYRP analysis, Ms. Bulkley used actual authorized returns for gas utilities as the measure of the cost of equity to determine the risk premium over the 30-year Treasury yield. Using the relationship between those two variables based on a regression analysis, she calculated an ROE range of 10.16% to 10.23% for the Companies. Id.; PGL Ex. 4.0 REV at 49, 50; NS Ex. 4.0 REV at 49; 50. North Shore and Peoples Gas observes that Mr. Walters also employed the BYRP model on behalf of CUB/PCR and estimated the Companies’ cost of equity on that basis to be 9.80%. CUB/PCR 1.0 at 52.

The Companies argue that Staff’s criticism of the risk premium approach (Staff Ex. 3.0 at 40) ignores the Commission’s observation that all of the cost of equity models have their strengths and weaknesses. The Commission has recognized that the approach can have “proxy sample flaws and can use outdated data.” 2019 Nicor Order at 118. NS and PGL do not believe the conclusion that the approach should not be considered because of “the difficulty in establishing the ‘correct’ risk premium” is logical. Staff Ex. 3.0 at 41
(quoting 2010 PGL/NS Order at 93-94). As Ms. Bulkley noted, this criticism “could be directed at almost any individual component of any of the cost of equity models,” such as the growth rates for the DCF model and the betas for the CAPM analysis. NS-PGL Ex. 15.0 at 29. “However, just as the analysts and the Commission attempt to derive objective measures for the inputs to other models, so can the risk premium be objectively estimated in the BYRP analysis.” Id. at 29. Ms. Bulkley performed a regression analysis of equity premia to interest rates over a lengthy historical period and confirmed a strong inverse relationship between the two. Id. at 29.

The Companies add that Staff cites a number of prior Commission decisions rejecting the risk premium approach. Staff Ex. 3.0 at 40. They state that notably, however, only one of the 10 cases cited by Staff post-dates the 2019 Nicor Order. See N. Ill. Gas Co., Docket No. 21-0098, Order (Nov. 18, 2021).

NS and PGL conclude that Staff’s continuing opposition to the risk premium approach is baseless, as Staff’s claim that the approach relies on parameters that cannot be known with certainty applies equally to the DCF and CAPM models on which Staff relies. Accordingly, the Companies asserts that the Commission should consider NS’s and PGL’s BYRP analysis, which yields a cost of equity for the Companies of 10.16% to 10.23% and therefore supports the Companies’ requested 9.90% ROE. They highlight that even CUB/PCR’s BYRP result of 9.80% supports the Companies’ ROE request.

ECAPM

Ms. Bulkley relied on a second form of the CAPM analysis, the ECAPM, which “addresses the tendency of the ‘traditional’ CAPM to underestimate the cost of equity for companies with low beta coefficients [i.e., less than 1.0] such as regulated utilities. PGL Ex. 4.0 REV at 46; NS Ex. 4.0 REV at 46. The Companies explain that this version of the CAPM does so by calculating the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75% to that result. The model then applies a 25% weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result. Id.; PGL 4.0 REV at 45; NS 4.0 REV at 45. The Companies note that Ms. Bulkley’s ECAPM result for them was a cost of equity in the range of 10.97% to 11.73% compared to her CAPM range of 10.37% to 11.38%. Id.; PGL Ex. 4.0 REV at 46; NS Ex. 4.0 REV at 46.

The Companies state that Staff opposes consideration of the ECAPM, claiming that the analysis adjusts beta twice, once through the use of adjusted betas from published sources and a second time through the weighting in the ECAPM formula. Staff Ex. 3.0 at 37-38. They criticize Ms. Kight-Garlisch’s use of a misinterpretation of a single academic article to support this position. Staff Ex. 3.0 at 37; Staff Ex. 11.0 at 6-7. NS and PGL claim that far from supporting the notion that the ECAPM represents a “double adjustment” of the beta for the same purpose, the article actually demonstrates that further adjustment beyond adjusting betas is necessary to improve the accuracy of the CAPM’s predictions. The study showed that whether raw or adjusted betas were used, “the CAPM understated the return for utilities with betas less than 1.0, meaning that further adjustment . . . is required in order to more accurately predict the cost of equity.” NS-PGL Ex. 26.0 at 6-7. The Companies point out that other academic sources support
the ECAPM’s use to correct the biases in the CAPM, including a study showing that “the ECAPM significantly outperformed the traditional CAPM at predicting the observed risk premium for the various utility subgroups.” NS-PGL Ex. 15.0 at 25-26. They also note that the ECAPM is accepted by at least two other state commissions. *Id.* at 27.

The Companies understand that Ms. Kight-Garlisch correctly noted that the Commission has previously rejected the ECAPM based on the Staff position (Staff Ex. 3.0 at 39), but they argue the Commission should reconsider its position based on the conclusive evidence in this case that Staff’s “double beta adjustment” theory is baseless. As explained by Ms. Bulkley, the adjustment of the beta and the ECAPM weighting accomplish two separate things. “The purpose of adjusting beta is to account for the tendency of beta to trend back over time to the market beta of 1.00,” whereas “[t]he purpose of the ECAPM is to account for the fact that the risk-return relationship is flatter than what is estimated by the CAPM. While beta is not observable and must be estimated, the theory behind the ECAPM is that even if the true value of a stock’s beta were observable, the CAPM would understate the return for stocks with betas less than 1.00 and overstate the results for stocks with betas greater than 1.00.” NS-PGL Ex. 15.0 at 22, 23. The Companies contend that Ms. Bulkley demonstrated this to be true by calculating the risk-return relationship of her CAPM and ECAPM analyses, which confirms that “the slope of the ECAPM is flatter than the CAPM, indicating that the CAPM is likely understating the return for companies with betas less than 1.00 and overstating the return for companies with betas greater than 1.00.” *Id.* at 24.

In addition, NS and PGL insist that Figure 1 from Ms. Bulkley’s surrebuttal testimony shows conclusively that the adjustment to the beta and the ECAPM beta weighting address two different aspects of the model and do not, as Staff claims, constitute “a double adjustment that overcompensates for the observed flatness of the security market line.” Staff Ex. 3.0 at 38. They explain that when the beta is adjusted to recognize that betas revert to the market mean of 1.0, the resulting adjustment is shown in Figure 1 by the red arrow in the lower right-hand corner. Separately, when the ECAPM is used to recognize that the risk/return relationship is flatter than predicted by the CAPM, the resulting adjustment is shown by the green arrow in the lower right-hand corner. NS-PGL Ex. 26.0 at 8. The Companies state this is conclusive proof of the fallacy of the Staff position that the ECAPM constitutes a “double adjustment” of the beta. Accordingly, they argue that Staff’s opposition to the model is unsupported by substantial evidence and it should be considered by the Commission in setting the Companies’ authorized ROE.

**Response to CUB/PCR/City’s Cost of Common Equity Analysis**

The Companies argue that CUB/PCR/City ROE proposal of 9.50% is on its face unreasonable. It is lower than recent authorized ROEs for other gas utilities in Illinois and nationally and is contrary to the indisputable evidence that the Companies’ costs of equity have increased substantially since their last rate cases. NS and PGL state that according to CUB/PCR/City’s own evidence, interest rates are expected to remain elevated through at least 2024. NS-PGL Ex. 15.0 at 6-7. And national gas utility authorized ROEs have increased by 20 basis points thus far in 2023 compared to 2022, averaging 9.70%. *Id.* at 8. Yet, the Companies note, CUB/PCR/City urge the Commission to set the Companies’ authorized ROE below the 9.67% ROE the Commission set for North Shore in 2021. The Companies further state that CUB/PCR/City’s analysis supporting that proposal, which
should be rejected, is affected by numerous flaws that result in a below-market cost of equity estimate, as described by Ms. Bulkley. NS-PGL Ex. 15.0 at 33-53; NS-PGL Ex. 26.0 at 12-15. They argue that if those flaws are corrected, the CUB/PCR/City cost of equity is 9.94%. NS-PGL Ex. 15.0 at 54-55.

b. Staff’s Position

Staff recommends that the Commission reject the Companies’ proposed cost of common equity and adopt Staff’s proposed cost of common equity of 9.83%. Staff witness Kight-Garlisch computed Staff’s proposed cost of common equity using the DCF model and the CAPM, which is a risk premium model. Staff explains that because the Companies do not have market-traded common stock, DCF and risk premium models cannot be applied directly to the Companies. Thus, Ms. Kight-Garlisch applied both models to a sample of public utilities comparable in risk to the natural gas distribution operations of the Companies (“Proxy Group”). Staff Ex. 3.0 at 3. To select a sample of gas distribution companies that are similar in risk to the gas distribution operations of the Companies, she began with a list of all companies categorized as a natural gas utility by Value Line. She then eliminated companies that: (1) do not have investment grade credit ratings from either S&P or Moody’s, (2) do not pay quarterly dividends, (3) do not have growth rate estimates from S&P Global Capital IQ Pro (“Capital IQ”) or Zacks Research Wizard (“Zacks”), and (4) are a party to a merger or other significant transaction. Id. at 3; Staff Ex. 11.1 at 2. Her Proxy Group consisted of the following companies: Atmos Energy Corporation, New Jersey Resources Corporation, NiSource Inc., Northwest Natural Gas Holding Company, ONE Gas Inc., and Spire Inc. Staff Ex. 3.0 at 3.

Staff’s Cost of Common Equity Analysis

Staff further explained Staff witness Kight-Garlisch’s cost of common equity analysis in greater detail below.

**DCF**

Staff explains that in order for a utility to attract common equity capital, it must provide a rate of return on common equity sufficient to meet investor requirements. The DCF analysis establishes a rate of return directly from investor requirements. According to DCF theory, a security price equals the present value of the cash flow investors expect it to generate. Specifically, the market value of common stock equals the cumulative value of the expected stream of future dividends after each dividend is discounted by the investor-required rate of return. Staff Ex. 3.0 at 4.

The DCF analysis, Staff states, is generally employed to determine the appropriate stock prices given a specified discount rate. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that stock prices embody. The companies in the Proxy Group pay dividends quarterly; therefore, Staff witness Kight-Garlisch applied a quarterly constant growth DCF model and a quarterly non-constant growth DCF (“NCDCF”) model to measure the annual required rate of return on common equity. Id. at 5. Staff states that both models, DCF and NCDCF, use three to five-year earnings growth rates that reflect the expectations of investors. Id. at 7. There are three stages of growth in the NCDCF model and the constant growth DCF assumes a constant growth rate into perpetuity.
Staff further explains that the DCF model also requires the measurement of stock prices. A current stock price reflects all information that is available and relevant to the market; thus, it represents the market’s assessment of the common stock’s current value. Staff witness Kight-Garlisch measured each company’s current stock price with its closing market price from April 12, 2023. Since current stock prices reflect the market’s concurrent expectations of both the cash flows the securities will produce and the rate at which those cash flows are discounted, an observed change in the market price does not necessarily indicate a change in the required rate of return on common equity. Rather, a price change may reflect investors’ re-evaluation of the expected dividend growth rate. In addition, Staff states that stock prices change with the approach of dividend payment dates. Consequently, when estimating the required return on common equity with the DCF model, one should measure the expected dividend yield and the corresponding growth rate concurrently. Staff opines that using a historical stock price along with current growth expectations or combining an updated stock price with past growth expectations will increase the inaccuracy of the estimate of the market-required rate of return on common equity.

Staff notes that the DCF model also requires the calculation of Next Dividend Payment Date. Staff witness Kight-Garlisch assumed the current declared dividend rate will remain in effect for a minimum of four quarters and then adjust during the same quarter it changed during the preceding year; if the utility did not change its dividend during the last year, she assumed the rate would change during the next quarter. The average expected growth rate was applied to the current declared dividend rate to estimate the expected dividend rate. Staff Ex. 3.0, Schedule 3.03 presents the quarterly dividends for the prior year and Schedule 3.04 presents the expected quarterly dividends for the coming year. Id. at 11-12.

Staff witness Kight-Garlisch’s constant growth DCF estimate is 9.40% and the NCDCF estimate is 8.23%, as shown on Staff Ex. 3.0, Schedule 3.05. Staff witness Kight-Garlisch’s estimate of the required rate of return on common equity for the Proxy Group is based on the average of the constant growth DCF and the NCDCF estimates, or 8.81%. The DCF estimates for the Proxy Group were derived from the growth rates presented on Schedule 3.01, the stock prices and dividend payment dates presented on Schedule 3.03, and the expected quarterly dividends presented on Schedule 3.04. Staff witness Kight-Garlisch averaged her constant grow DCF and NCDCF estimates. Staff points out that she included the NCDCF results, which employs the long-term economic growth rate for the Proxy Group to avoid overstating the cost of equity for the Companies. Id. at 13.

**CAPM**

Staff explains that the CAPM is based on the theory that the market-required rate of return for a given risk-bearing security equals the risk-free rate of return plus a risk premium that investors expect in exchange for assuming the risk associated with that security. The risk-free rate of return is the rate of return on an investment with zero risk. Staff asserts that this represents the absolute minimum return an investor demands as compensation for deferring consumption. Mathematically, a risk premium equals the difference between the expected rate of return on a risk factor and the risk-free rate. If the risk of a security is measured relative to a portfolio, then multiplying that relative
measure of risk and the portfolio’s risk premium produces a security-specific risk premium for that risk factor. Staff Ex. 3.0 at 13.

According to Staff, the CAPM methodology is consistent with the theory that investors are risk averse. That is, investors require higher returns to accept greater exposure to risk. In the CAPM, the risk factor is market risk, which is defined as risk that cannot be eliminated through portfolio diversification. Staff notes that to implement the CAPM, one must estimate the risk-free rate of return, the expected rate of return on the market portfolio, and a security or portfolio-specific measure of market risk. Id. at 14.

To determine the risk-free rate, Staff witness Kight-Garlisch examined the yield on four-week U.S Treasury bills and thirty-year U.S. Treasury bonds. She testified that the proxy for the nominal risk-free rate should contain no risk premium and reflect similar inflation and real risk-free rate expectations to the security being analyzed through the risk premium methodology. The real risk-free rate and inflation expectations compose the non-risk related portion of a security’s rate of return. Id. Accordingly, Staff opines that the federal government’s fiscal and monetary authority makes securities of the U.S. Treasury virtually free of default risk. Staff witness Kight-Garlisch testified that the better proxy for long-term risk-free rate is the U.S Treasury bill based upon an analysis of Energy Information Administration’s (“EIA”) and Survey of Professional Forecasters (“Survey”) forecasts of inflation and real GDP growth expectations.

Staff witness Kight-Garlisch explained that the risk-free and the real GDP growth rate should be similar. Risk-free securities provide a rate of return sufficient to compensate investors for the time value of money, which is a function of production opportunities, time preferences for consumption, and inflation. The real risk-free rate excludes the premium for inflation. Staff Ex. 3.0 at 18-19.

Staff witness Kight-Garlisch estimated the expected rate of return on the market portfolio by conducting a DCF analysis on the firms composing the S&P 500 as of March 31, 2023. That analysis used dividend information and closing market prices reported by Zacks. Staff states that April 3, 2023, growth rate estimates were also obtained primarily from Zacks and secondarily from Capital IQ. Firms not paying a dividend as of March 31, 2023, or for which neither Zacks nor Capital IQ growth rates were available were eliminated from the analysis. Companies with growth rates greater than 30% or less than -30% were also eliminated from the analysis. Staff notes that the resulting company-specific estimates of the expected rate of return on common equity were then weighted using market value data from Zacks. Ms. Kight-Garlisch concluded that the estimated weighted average expected rate of return for the remaining firms, composing 73.53% of the market capitalization of the S&P 500, equals 12.65%. Id. at 19.

Staff witness Kight-Garlisch measured beta by using Value Line betas, Zacks betas, and a regression analysis to estimate the beta of the Proxy Group. Id. at 20. She adjusted raw beta to produce a more accurate forward-looking beta estimate. Ms. Kight-Garlisch relied upon multiple approaches to calculate beta for her sample since true betas are forward-looking measures of investors’ expectations of market risk. As such, true betas are not observable. Thus, Staff expounds that betas that Staff calculates and betas that Value Line, Zacks, and other financial information services publish are proxies for true betas. Therefore, like all proxies, beta estimates are subject to measurement error.
Thus, there is no single, definitively “correct” beta for a given company. Staff observes that its analysis relies on multiple models involving multiple companies and contends that using multiple approaches to estimate beta mitigates the effect on Ms. Kight-Garlisch’s cost of common equity estimate of measurement error in her sample’s beta estimate. Id. at 23. Staff notes that Ms. Kight-Garlisch’s beta for the Proxy Group is 0.80 and her CAPM estimate for the required rate of return on common equity for the Proxy Group is 10.96%. Id. at 24.

Staff points out that along with the DCF, NCDCF, and CAPM cost of equity analyses, Ms. Kight-Garlisch considered the observable 5.09% rate of return the market currently requires on less risky A rated long-term utility debt. The utility debt data is as of April 10, 2023. Id. at 24-25.

Staff concludes that Ms. Kight-Garlisch recommended the Companies’ investor-required rate of return on common equity equals 9.83% based on her analysis. Id. at 25. She applied a 0.06% risk adjustment to her 9.89% ROE estimate for the Proxy Group to arrive at her 9.83% recommendation for the Companies. Id. at 27. Staff argues that the 0.06% risk adjustment was necessary and appropriate because the Companies are less risky than the Proxy Group. It is Staff’s view that if no adjustment was made, the return on common equity estimate derived from the Proxy Group would be too high for the Companies. Staff maintains that Ms. Kight-Garlisch’s analysis demonstrates the adjustment was necessary because it indicates that the risk of the Companies is slightly lower than the overall risk of the Proxy Group. She explained that issue credit ratings assigned to a company reflect both business and financial risk. Since issuer credit ratings reflect a company’s overall risk, she compared the issuer credit ratings of the Proxy Group to those of Peoples Gas since North Shore is not rated by the credit rating agencies. Staff adds that the Proxy Group has an average rating of A3 from Moody’s and an average credit rating of A- from S&P, as shown on Schedule 3.07. Peoples Gas currently has an A2 credit rating from Moody’s and an A- credit rating from S&P. Thus, Staff submits that the cost of common equity for the Companies needs to be adjusted downward to reflect that lower level of risk. Id. at 26-27.

Staff notes that the 0.06% adjustment is based on the 11.3 basis points credit yield spread between A2 and A3 rated utility bonds, which, as discussed above, represents the risk differential between the Companies and the Proxy Group. Staff explains that since Peoples Gas has a split rating (A2 from Moody’s and A- from S&P), Ms. Kight-Garlisch divided the 11.3 one-notch adjustment in half to reflect the split rating. Thus, she adjusted the Proxy Group cost of common equity estimate of 9.89% by 0.06% to get her recommended cost of common equity for the Companies of 9.83%. Staff states the primary difference between its recommended ROE of 9.83% for the Companies and the Companies’ requested ROE of 9.90% is this risk adjustment. Staff Ex. 11.0 at 1.

Response to CUB/PCR/City’s Cost of Common Equity Analysis

Staff explains that CUB/PCR witness Walters estimated the ROE for the Companies using DCF, CAPM, and risk premium models. CUB/PCR/City Ex. 1.0 at 33-62. His analysis: (a) included average stock prices in his DCF analyses; (b) included a forecasted Treasury bond yield to estimate the risk-free rate in his CAPM analyses; (c) relies exclusively on weekly beta estimates for his CAPM analyses; and (d) relies on a
bond yield plus risk premium model, in addition to DCF and CAPM analyses, to estimate the ROE for the Companies. *Id.*

Staff states that the shortcomings of (a) through (d) are addressed below in its response to the Companies' analysis. Staff contends that despite those shortcomings, Mr. Walter’s recommended ROE is more reasonable than Companies witness Bulkley’s recommended ROE because Mr. Walter’s analysis does not include any improper adjustments or ECAPM analyses. Staff Ex. 11.0 at 9.

*Response to the Companies’ Cost of Common Equity Analysis*

Staff witness Kight-Garlisch testified that there are several significant flaws in Ms. Bulkley’s analysis, which led her to overestimate the cost of common equity for the Companies. *Id.* at 29

**DCF**

**Growth Rates**

With regard to the DCF analysis, Staff contends that the Value Line growth rates that Ms. Bulkley used in her DCF analysis are inflated. Staff states that while Ms. Bulkley used Value Line long-term earnings per share (“EPS”) growth rates in her DCF analysis, she did not consider the Value Line projected growth in dividends per share (“DPS”). Ms. Bulkley should instead use the Value Line projected growth in DPS. Staff explains that EPS growth rates are generally used in the DCF models as a proxy for DPS growth rates since there are very few analysts’ long-term forecasts of DPS growth. If DPS growth estimates are available, then there is no need to use a proxy for DPS growth according to Staff. Thus, the Value Line projected growth in DPS should not be ignored in determining the growth rate used in the DCF calculations. Staff claims that ignoring the growth of dividends in this case leads to an upwardly biased estimate of the investor-required rate of return on common equity. Substituting the Value Line DPS growth estimates for the Value Line EPS growth estimates in Ms. Bulkley’s DCF analyses results in an 87 to 88 basis points decrease in her mean ROE estimates and a 47 to 60 basis points decrease in her median ROE estimates. Staff Ex. 3.0 at 29-30.

**Historical Date**

Staff witness Kight-Garlisch testified that Ms. Bulkley’s use of historical data in her DCF analysis is problematic for several reasons. First, historical data favors outdated information that the market no longer considers relevant over the most-recently available information. Second, historical data reflects conditions that may not continue into the future. In other words, use of average historical data implies that securities data will revert to a mean. Staff explains that even if securities data were mean-reverting, there is no method for determining the true value of that mean let alone the length of time over which mean reversion will occur. Consequently, sample means, which depend upon the selected measurement period, are used. Thus, any measurement period chosen is arbitrary, rendering the results uninformative.

Staff challenges Ms. Bulkley’s use of an average of the last 30-day, 60-day, and 180-day trading of stock prices ending November 30, 2022, to calculate the dividend yields for her DCF analyses. Staff asserts that she implies that her use of historical data
to estimate the dividend yield is an attempt to reduce measurement error when Ms. Bulkley states that she used an average dividend yield in order to guard against biases that may arise on a single trading day. However, while it is true that measurement error is a problem inherent in cost of common equity analysis and should be reduced whenever possible, introducing old stock prices into an analysis simply substitutes one alleged source of measurement error, volatile stock prices, for another, irrelevant stock prices. Staff avers that stock prices can be influenced by temporary imbalances in supply and demand. However, any distortions such imbalances might have on the measured cost of common equity can be reduced through the use of samples, a technique which Ms. Bulkley already applies. Id. at 30-32.

Staff points out that the Commission previously rejected the use of historical dividend yields in determining a company’s cost of capital, including in a case in which Ms Bulkley provided testimony. Id. at 32. Ms. Bulkley testified on ROE in that case, relying upon historical stock prices in her DCF analyses, and the Commission declined to adopt the use of historical stock prices in DCF analyses. Ill.-Am. Water Co., Docket No. 22-0210, Order at 100-101 (Dec. 15, 2022). Additionally, Staff notes that the Commission has previously rejected DCF analyses that use historical dividend yields, noting its preference for the use of spot (current) common stock prices in the DCF model instead of the use of average prices. N. Ill. Gas Co., Docket No. 21-0098, Order at 94 (Nov. 18, 2021); Consumers Ill. Water Co., Docket No. 03-0403, Order at 42 (Apr. 13, 2004). Staff contends the Commission should reject Ms. Bulkley’s use of historical data in her ROE analysis in this proceeding as it has done in the past. Staff Ex. 3.0 at 32.

CAPM

Beta Estimates

With regard to CAPM beta estimates, Staff asserts that Ms. Kight-Garlisch had concerns for several reasons with Ms. Bulkley’s beta estimates which she obtained from Value Line and Bloomberg. Id. at 33. First, both beta estimates that Ms. Bulkley employs in her CAPM are calculated using weekly return intervals. Staff states this is problematic because the major reason for observed variation among published betas is the interval effect (i.e., monthly returns versus weekly returns) due to non-synchronous trading, which is greater for weekly data than for monthly data. Frank K. Reilly and David J. Wright, “A comparison of published betas,” The Journal of Portfolio Management, Spring 1988 at 64-69. By relying exclusively upon betas calculated using weekly data, Ms. Bulkley has introduced bias into her CAPM analysis that could have been mitigated by including a beta estimate derived from monthly return intervals. Staff asserts that the Commission has expressed its preference for using a combination of weekly and monthly beta estimates for this very reason, such as in its Order in Docket Nos. 09-0306 through 09-0311 (cons.). Cent. Ill. Light Co., Docket Nos. 09-0306 through 09-0311 (cons.), Order at 213 (Apr. 29, 2010). This is why Staff recommends that the Commission disregard Ms. Bulkley’s CAPM results, which rely exclusively on weekly beta estimates rather than a combination of weekly and monthly beta estimates.

Forecasted Risk-Free Rate
With regard to risk-free rate of return in Ms. Bulkley’s CAPM analysis, Staff witness Kight-Garlisch expressed concerns with her forecasted risk-free rates because accurately forecasting the movement of interest rates is problematic. Staff Ex. 3.0 at 35. Staff notes that Ms. Bulkley uses three estimates of the risk-free rate of return: (1) the 30-day historical average yield on 30-year U.S. Treasury bonds as of November 30, 2022 (4.07%); (2) an average projected 30-year U.S. Treasury bond yield for the first quarter of 2023 through the first quarter of 2024 (4.06%) from Blue Chip Financial Forecasts (“Blue Chip”); and (3) an average projected 30-year U.S. Treasury bond yield for 2024 through 2028 (3.90%) from Blue Chip.

Staff witness Kight-Garlisch testified that given the difficulty of accurately forecasting interest rates, the Commission should, instead, continue to rely on current, observable market interest rates, which, unlike forecasts, reflect market forces and investors’ expectations for the future. Staff Ex. 3.0 at 35. Staff witness Kight-Garlisch further testified the use of current, observable market interest rates renders the use of forecasted interest rates unnecessary because U.S. Treasury bond yields reflect all relevant, available information, including investor appraisals of the value of current expectations for the future.

Staff points out that the Commission has previously declined to adopt analyses that use projected U.S. Treasury bond yields as proxy for the risk-free rate of return. Staff also points out that the Commission has repeatedly stated its preference for using current observable U.S. Treasury bond yields to estimate the risk-free rate because it is impossible to accurately predict future interest rates. See, e.g., Ill.-Am. Water Co., Docket No. 22-0210, Order at 101 (Dec. 15, 2022); N. Ill. Gas Co., Docket No. 21-0098, Order at 94-95 (Nov. 18, 2021); Liberty Util. (Midstates Nat. Gas) Corp., Docket No. 14-0371, Order at 66 (Feb. 11, 2015); Docket Nos. 14-0224/14-0225 (cons.), Order at 133; Ill.-Am. Water Co., Docket No. 11-0676, Order at 108-109 (July 31, 2012); Cent. Ill. Light Co., Docket Nos. 09-0306 through 09-0311 (cons.), Order at 219 (Apr. 29, 2010); Ill.-Am. Water Co., Docket No. 09-0319, Order at 112 (Apr. 13, 2010); Cent. Ill. Light Co., Docket No. 02-0837, Order at 37 (Oct. 17, 2003); Cent. Ill. Pub. Serv. Co. and Union Elec. Co., Docket Nos. 02-0798/03-0008/03-0009 (cons.), Order at 85 (Oct. 22, 2003); Commonwealth Edison Co., Docket No. 94-0065, Order at 93 (Jan. 9, 1995).

**ECAPM**

Staff continues that in addition to the problems discussed above with the use of only weekly betas and a forecasted risk-free rate, which Ms. Bulkley also uses in her ECAPM analysis, Staff witness Kight-Garlisch expressed additional concerns with the Companies’ CAPM analysis. Staff states that Ms. Bulkley’s ECAPM ostensibly attempts to adjust the CAPM for the flatness of the empirically measured security market line (“SML”) relative to the predicted SML. Ms. Bulkley applies to both her traditional CAPM and her ECAPM the same Value Line and Bloomberg adjusted betas. However, Staff counters that by using adjusted betas in her traditional CAPM, Ms. Bulkley has already effectively transformed her traditional CAPM into an ECAPM. By using adjusted betas in the ECAPM model, Staff argues Ms. Bulkley effectively adjusts twice for the flatness of the empirical SML and, thus, inflates the estimate of her sample’s cost of common equity. Hence, the Commission should reject Ms. Bulkley’s ECAPM results. Staff Ex. 3.0 at 37.
Staff observes that the Commission has rejected such application of the ECAPM in several prior proceedings. See, e.g., Ill.-Am. Water Co., Docket No. 22-0210, Order at 101-102 (Dec. 15, 2022); Ill.-Am. Water Co., Docket No. 11-0767, Order at 109 (July 31, 2012); Consumers Ill. Water Co., Docket No. 03-0403, Order at 41-42 (Apr. 13, 2004); MidAmerican Energy Co., Docket No. 01-0696, Order at 22 (Sept. 11, 2002); and MidAmerican Energy Co., Docket No. 01-0444, Order at 14-17 (Mar. 27, 2002). To bolster its position, Staff points to one of the dockets, Docket No. 11-0767, in which the Order explicitly states that the use of adjusted betas in the ECAPM is inappropriate and would result in inflated estimates of the samples’ cost of common equity. Ill.-Am. Water Co., Docket No. 11-0767, Order at 109 (July 31, 2012).

BYRP

Staff also identified several flaws with Ms. Bulkley’s bond risk premium regression analysis. First, the measurement period for the analysis is completely arbitrary. Second, the returns included are authorized by regulatory bodies and are not necessarily market-based returns but rather are legal determinations. Staff Ex. 3.0 at 40. Moreover, Staff notes that the Commission has rejected the use of bond yield plus risk premium models to determine the cost of common equity in several prior proceedings. See, e.g., N. Ill. Gas Co., Docket No. 21-0098, Order at 74-75, 86, 94 (Nov. 18, 2021); MidAmerican Energy Co., Docket No. 14-0066, Order at 48-49 (Nov. 6, 2014); Ameren Ill. Co., Docket No. 13-0192, Order at 165 (Dec. 18, 2013); Ameren Ill. Co., Docket No. 11-0282, Order at 125 (Jan. 10, 2012); Ill.-Am. Water Co., Docket No. 11-0767, Order at 110 (Sept. 19, 2012); Aqua Ill., Inc., Docket No. 11-0436, Order at 38 (Feb. 16, 2012); N. Shore Gas Co. and Peoples Gas Light & Coke Co., Docket Nos. 12-0511/12-0512 (cons.), Order at 207 (June 18, 2013); N. Shore Gas Co. and Peoples Gas Light & Coke Co., Docket Nos. 11-0280/11-0281 (cons.), Order at 139 (Jan. 10, 2012); N. Shore Gas Co. and Peoples Gas Light & Coke Co., Docket Nos. 09-0166/09-0167 (cons.), Order at 128 (Jan. 21, 2010); and N. Shore Gas Co. and Peoples Gas Light & Coke Co., Docket Nos. 07-0241/07-0242 (cons.), Order at 93-94 (Feb. 5, 2008).

Size-Based Risk Adjustment

Staff states that while Ms. Bulkley did not make a direct size-based business risk adjustment in her cost of equity recommendation, she did so indirectly with respect to North Shore in her determination of an ROE range. Staff Ex. 3.0 at 42. Her size-based risk adjustment is based on the difference in size between the market values of her proxy group and a hypothetical estimate of what both Companies’ market value would allegedly be if each were traded. It is Staff’s position that a size-based risk premium for a utility is contrary to financial theory and unsupported by empirical studies. Id. Staff witness Kight-Garlisch testified there is no theoretical basis for a sized-based risk premium. She explained since there is no theoretical basis for it, to the extent that a correlation between firm size and return exists, that relationship is likely the result of some other factor or factors that are related to both size and return, such as liquidity or information costs, rather than a direct relationship between size and return.

Staff posits that if a company’s securities are less liquid or the availability of information regarding the company is more restricted than the average security, then adding a size-based premium to an analysis of the company’s cost of common equity

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might be proper. However, Staff does not believe Ms. Bulkley has provided any evidence to demonstrate that a size premium is warranted for utilities. The Ibbotson data that Ms. Bulkley points to as support for her size-based adjustment was not restricted to utilities, but is based on the entire population of NYSE, AMEX, and NASDAQ-listed securities, which are heavily weighted with industrial stocks. Staff explains that unlike most companies, utilities’ earnings are regulated through proceedings in which substantial amounts of information, including their rates and conditions of service, are publicly reported. Therefore, the cost of obtaining information regarding smaller utilities is unlikely to be as high as that of unregulated companies that are similar in size. Also, utilities are subject to uniform reporting requirements, regardless of size. Therefore, the cost of obtaining information regarding smaller utilities is unlikely to be any higher than the cost of obtaining information regarding larger utilities. Thus, Staff states the only basis Ms. Bulkley presents for her size-based risk premium is inapplicable.

Staff adds that in contrast with Ms. Bulkley’s claims, a study by Annie Wong, reported in the Journal of the Midwest Finance Association, specifically found no justification for a size premium for utilities. Id. at 43-44. Ms. Kight-Garlisch further testified, even for non-utilities, evidence of the existence of a size-based risk premium is not very strong.

Staff underscores its point by noting that Ms. Kight-Garlisch also testified that although the relationship between firm size and return has been studied from a variety of angles, no theoretical or empirical support has been found for the notion that, all else equal, investors require higher rates of return for smaller utility stocks than they do from larger utility stocks. Id. at 46.

Additionally, Staff argues Ms. Bulkley’s consideration of a business risk adjustment based on the size of North Shore is unwarranted since North Shore is also a wholly owned subsidiary within a much larger organization. Id. In fact, Staff asserts in North Shore’s 2014 reorganization case (Docket No. 14-0496), through which it became a wholly owned subsidiary of WEC, the joint applicants repeatedly cited their expectation that North Shore will have enhanced access to capital markets on reasonable terms as a result of the scale of the newly formed corporation. See Docket No. 14-0496, Application at 1-2; JA Ex. 1.0 at 14; and JA Ex. 3.0 at 9-10.

Finally, Staff notes that the Commission has rejected size-based adjustments in multiple cases and it should reject the Companies’ business risk adjustment based on the size of North Shore in this docket also. Staff states that the Commission rejected the same type of size-based business risk adjustment in several rate cases. Util. Servs. of Ill., Inc., Docket No. 21-0198, Order at 83 (Dec. 1, 2021); Ill.-Am. Water Co., Docket No. 07-0507, Order at 90-91 (July 30, 2008); Consumers Ill. Water Co., Docket No. 97-0351, Amended Order at 39 (June 17, 1998); Aqua Ill., Inc., Docket No. 03-0403, Order at 43 (Apr. 13, 2004).

In conclusion, Staff urges the Commission to adopt its recommended ROE of 9.83% and reject the Companies’ and CUB/PCR’s ROE proposals.
c. **AG’s Position**

The AG asks the Commission to adopt the CUB/PCR/City rate of return proposal, which includes an ROE of 9.5% for both Companies, resulting in an overall rate of return of 7.03% for NS and 6.88% for PGL. The AG notes that as detailed herein and demonstrated by the litany of public comments from ratepayers, the Companies’ rates are increasingly unaffordable. Illinois case law makes clear that “[t]he rate making process … involves a balancing of the investor and the consumer interests.” *Ill. Bell Tel. Co.*, 414 Ill. at 287 (internal quotations and citations omitted). The AG reasserts that the state’s highest court has held that “a just and reasonable rate can never exceed—perhaps can rarely equal—the value of the service to the consumer … .” *State Pub. Util. Comm’n ex rel. City of Springfield*, 291 Ill. at 216 (1919). Further, it is well settled that “if the rightful expectations of the investor are not compatible with those of the consuming public, it is the latter which must prevail.” *Camelot Util., Inc.*, 51 Ill. App. 3d at 10 (3d Dist. 1977). The AG therefore asserts that it is unacceptable for PGL and NS to ask for such high profit rates when their ratepayers are already struggling to pay their bills. The AG argues the Companies’ proposals are unjustified and unreasonable.

To support its position, the AG points to Mr. Walters’ testimony, in which he testified the Companies and Staff overstate the cost of equity and risk undertaken by the Companies’ shareholders, resulting in unreasonable ROEs. CUB/PCR/City Ex. 2.0 at 5, 10. The AG argues that Mr. Walters’ analysis is supported by empirical data and provides an ROE that fairly balances the interests of the Companies’ shareholders and ratepayers. For these reasons, the AG requests that the Commission adopt Mr. Walters’ 9.5% ROE for both Companies.

d. **CUB/PCR/City’s Position**

CUB/PCR/City request that the Commission adopt CUB/PCR/City witness Walters’ recommended 9.50% ROE, which CUB/PCR/City argue achieves the careful balance of shareholder and consumer interests that the Act, established Commission practice, and court precedent require. CUB/PCR/City contend the Commission should reject Peoples’ and North Shore’s proposed ROEs of 9.9%, arguing this figure drastically overstates the Companies’ costs of capital and would impose exorbitant costs on ratepayers for no purpose other than to increase their profit margins. CUB/PCR/City also consider Staff’s recommended ROE of 9.83% a more reasonable alternative to the Companies’ proposal, though CUB/PCR/City argue the results of Staff witness Kight-Garlisch’s otherwise well-reasoned analysis are skewed by the inclusion of a CAPM result of 10.96% that is based on an unreasonable market risk premium.

CUB/PCR/City note that the U.S. Supreme Court precedent in *Hope* and *Bluefield* governs what constitutes a just and reasonable utility rate of return. *Bluefield*, 262 U.S. 679; *Hope*, 320 U.S. 591. Under these precedents, a utility is entitled only to a return sufficient to maintain its financial integrity and to attract capital at reasonable terms. The return is to be commensurate with the return investors could earn by investing in other companies of comparable risk. *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603. “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.” *Bluefield*, 262 U.S. at 693. CUB/PCR/City emphasize the phrase “under efficient and economical management,” to underscore that the Companies are not entitled to recover their actual costs from ratepayers if those actual costs are not the product of efficient and economical management.

CUB/PCR/City also note that Section 9-201(c) of the Act obligates the Commission to set just and reasonable rates. 220 ILCS 5/9-201(c). The Act’s stated purpose is to “prevent exorbitant rates and unjust discrimination and undue preferences in rates” and to protect consumers. *Springfield Gas & Elec. Co. v. Springfield*, 126 N.E. 739, 744 (1920). CUB/PCR/City note the return on equity is to be set no higher than necessary to meet the standards in *Hope* and *Bluefield*. CUB/PCR/City state that other jurisdictions have recognized that regulation is not intended to allow a utility a return on equity any higher than necessary to satisfy *Hope* and *Bluefield*. The rate regulation framework places the duty to prevent excessive prices and unfair business practices on the Commission. The statutes that establish the regulation of utilities reflect the weight of this obligation. *See Pub. Sys. v. Fed. Energy Regulatory Comm’n*, 606 F. 2d 973, 979 n.27 (D.C. Cir. 1979) (discussing the provisions of the Federal Power Act and the Natural Gas Act and stating, “protection of consumer includes maintaining the financial integrity of the regulated firm, but the focus of regulation remains control of the economic power of utilities that enjoy monopoly status.”).

CUB/PCR/City contend Mr. Walters’ recommended ROE is, as U.S. Supreme Court precedent requires, “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.” *Bluefield*, 262 U.S. at 693.

**CUB/PCR/City’s Cost of Common Equity Analysis**

Consistent with the Commission’s historical practice, Mr. Walters used several models based on financial theory to estimate the Companies’ costs of common equity. Those models were: 1) a constant growth DCF model using consensus analysts’ growth rate projections; 2) a constant growth DCF model using sustainable growth rate estimates; 3) a multi-stage growth DCF model; 4) a risk premium model; and 5) a CAPM. Mr. Walters applied these models to a group of publicly traded utilities with investment risks similar to the Companies’, referred to as the “Proxy Group.” CUB/PCR/City Ex. 1.0

**Proxy Group**

Mr. Walters utilized the same Proxy Group as the Companies’ cost of equity witness, Ms. Ann Bulkley. *Id.* at 32. The Proxy Group (identified in CUB/PCR/City Ex. 1.02) has an average corporate rating from Moody’s of A3, which is one notch lower than Peoples Gas’ rating from Moody’s, and an average corporate rating from S&P of A-, which is the same as Peoples Gas’. *Id.* North Shore is not a rated entity, but Mr. Walters testified he has no reason to believe NS’s rating would vary significantly from either Peoples Gas or the Proxy Group. *Id.* at 28. The Proxy Group, as reported in S&P Global Market Intelligence (“MI”) and Value Line has an average common equity ratio of 38.6% (including short-term debt) and 44.6% (excluding short-term debt), respectively. *Id.* at 32.
CUB/PCR/City found the Companies’ investment risk is relatively represented by the Proxy Group when taking into consideration the common equity ratios that Staff and CUB/PCR/City support. Furthermore, CUB/PCR/City assert that should the Commission adopt the Companies’ common equity ratios, a return on equity in the lower end of Mr. Walters’ range is warranted. CUB/PCR Ex. 1.0 at 31.

**DCF**

Mr. Walters used several versions of the DCF model in his cost of equity analysis. The DCF model calculates a stock price by summing the present value of expected future cash flows, discounted at the investor’s required rate of return or cost of capital. *Id.* at 33. The model requires a current stock price, expected dividend, and expected growth rate in dividends, as explained in Mr. Walters’ testimony. *Id.* at 34.

*Constant Growth DCF*

To determine the current stock price for the constant growth DCF model, Mr. Walters used the average of the weekly high and low stock prices of the utilities in the proxy group for a 13-week period ending on April 7, 2023. *Id.* at 34. Mr. Walters used this method because an average price is less susceptible to market variations. *Id.* at 34.

For the dividend in the constant growth DCF model, Mr. Walters used each proxy utility’s most recent quarterly dividend as reported in Value Line, annualized and adjusted for next year’s growth. *Id.* at 34.

To estimate expected growth in dividends for the constant growth DCF model, Mr. Walters relied on a consensus of estimates of independent securities analysts. *Id.* at 35. In support of this method, Mr. Walters illustrated that securities analysts’ growth estimates historically have been more accurate than extrapolations based on past growth rates data have been. *Id.* at 35. He found that analysts outperforming backward-looking assumptions makes sense because investors respond to analysts’ growth projections, which in turn is captured in observable stock prices. *Id.* To calculate analyst consensus expected growth rate, Mr. Walters calculated the mean of the most recent projections from Zacks, MI, and Yahoo! Finance that were available at the end of the 13-week sample (on April 7, 2023). *Id.* at 35. Mr. Walters weighted each of these analyst forecasts equally, as he saw no reason to treat any one of them as more or less credible than the others. *Id.* at 36. This method yielded an average growth rate for the proxy group of 5.83%. *Id.* at 36.

Mr. Walters’ constant growth DCF model, using these inputs from a 13-week analysis, produced average and median returns for the Proxy Group of 9.47% and 9.37%, respectively. *Id.* at 36. However, the average long-term growth rate of the proxy group of 5.83% is 46% higher than the projected 4.00% long-term growth rate of the U.S.’s gross domestic product (“GDP”). *Id.* at 36. Mr. Walters argued, based on the findings of academic and financial practitioner research, a utility’s long-term growth rate cannot exceed long-term GDP growth rate in perpetuity. *Id.* at 36-37, 43.

Further, based on his understanding of the Commission’s preference for use of the quarterly compounding form of the constant growth DCF model, Mr. Walters used a quarterly compounding adjustment to his DCF return estimates. *Id.* at 38. This
adjustment resulted in average and median returns of 9.52% and 9.42%, respectively. *Id.* at 38.

**Sustainable Growth DCF**

As mentioned above, Mr. Walters also utilized a Sustainable Growth DCF model. The sustainable growth rate is determined by the percentage of the utility’s earnings that is retained and reinvested in its plants and equipment. *Id.* at 38. In other words, the less a utility pays out in dividends to shareholders, the greater the sustainable growth rate. The average and median sustainable growth rates of the proxy group are 6.19% and 5.89% respectively. *Id.* at 39. These growth rates produce average and median DCF results of 9.84% and 9.96% respectively. *Id.* at 39. Again, as Mr. Walters noted, these growth rates are significantly beyond the anticipated growth rate of the U.S. GDP. *Id.* at 39-40.

**Multi-Stage DCF**

Mr. Walters also utilized a multi-stage DCF model. He contended that while the constant growth DCF model produces results that reflect the rational investment expectations in the coming years, it does not account for the reasonable expectation of a shift in the growth rate to a more sustainable growth rate. *Id.* at 40. A multi-stage DCF model accounts for a growth rate that changes over time. *Id.* at 40. The model reflects three growth periods: 1) a short-term growth period consisting of the first five years; 2) a transition period consisting of the next five years (years 6-10); and 3) a long-term growth period starting in year 11 and extending into perpetuity. *Id.* at 41-42.

For the short-term growth period, Mr. Walters relied on the consensus of analysts’ growth projections used in his Constant Growth DCF model. *Id.* at 42. For the transition period, growth rates were reduced or increased by an equal factor reflecting the difference between the analysts’ growth rates and the long-term sustainable growth rate. *Id.* at 42. For the long-term period, Mr. Walters assumed each company’s growth would converge to the maximum sustainable long-term growth rate. *Id.* at 42. Mr. Walters developed his long-term sustainable growth rate based on the consensus of long-term GDP growth rate projections by independent economists. *Id.* at 44. He explained that the Blue Chip Economic Indicators publishes the consensus for GDP growth projections twice a year. *Id.* at 44. Mr. Walters observed that these projections reflect current outlooks for GDP and are likely to have an influence on investor expectations of future growth outlooks. *Id.* at 44.

Mr. Walters also considered other sources of projected long-term GDP growth. *Id.* at 44. These sources included EIA-Annual Earnings Outlook, Congressional Budget Office, Moody’s Analytics, Social Security Administration, and the Economist Intelligence Unit. *Id.* at 45: Table CCW-7. Mr. Walters found these sources’ nominal and real GDP growth projections supported the use of the consensus for 5-year and 10-year projected GDP growth outlooks as a reasonable estimate of market participants’ long-term GDP growth. *Id.* at 45.

For the stock price, dividend, and growth rates in his multi-stage DCF model, Mr. Walters relied on the same 13-week average stock prices and most recent quarterly dividend payment data referenced in his constant growth DCF model. *Id.* at 46. For the
first stage of his multi-stage DCF model, he used the same consensus of analysts’ growth rate projections he used in his Constant Growth DCF model. *Id.* at 46. For the second stage (transition stage), he transitioned the growth rate from the first stage to the third stage using a straight linear trend. *Id.* at 46. For the third stage the long-term sustainable growth stage is 4% and is based on the consensus of economists’ long-term projected nominal GDP growth rate. *Id.* at 46.

Under this multi-stage DCF model, the average and median ROEs of the proxy group over a 13-week period are 8.05% and 7.99%, respectively. *Id.* at 46.

Based on all these DCF results, Mr. Walters suggests a reasonable ROE based on DCF models is 9.2%. *Id.* at 46.

**BYRP**

Mr. Walters also used a BYRP model for calculating an appropriate ROE for the Companies. CUB/PCR/City explain this model is based on the principle that investors require a higher return to assume greater risk. *Id.* at 47. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity, and the coupon payments on bonds represent contractual obligations. *Id.* at 47. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. *Id.* at 47. Therefore, common equity securities are considered to be riskier than bond securities. *Id.* at 47.

CUB/PCR/City further explain that this risk premium model is based on two estimates of an equity risk premium. *Id.* at 47. Mr. Walters calculated his first risk premium as the difference between commission-approved ROEs across the country and contemporary U.S. Treasury bonds for each year from 1986. *Id.* at 47. This produced an average risk premium of 5.64% across the entire period. *Id.* at 48. Smoothing with 5-year and 10-year rolling averages yielded ranges of 4.17% to 7.17% and 4.30% to 6.92%, respectively. *Id.* at 49. Mr. Walters based his second risk premium on the difference between regulatory commission-approved ROEs and the yields of contemporary utility stocks that were rated “A” by Moody’s, for the same timeframe. *Id.* at 48. This method yielded an overall average of 4.28% and 5- and 10-year rolling average ranges of 2.80% to 5.97% and 3.11% to 5.75%, respectively. *Id.* at 49.

Mr. Walters chose the time period since 1986 because public utility stock traded at a premium to book value in that period and the time period is long enough to smooth any abnormalities that may distort equity risk premiums. *Id.* at 48, 49. Thus, while market conditions and risk premiums vary over time, Mr. Walters determined this historical time period was sufficient to establish contemporary risk premiums. *Id.* at 49-50.

Mr. Walters then utilized other market evidence to determine an appropriate equity risk premium. Based on his risk premium studies, the current economic environment, current levels of interest rates and projections of those rates, Mr. Walters determined a move towards a more normalized equity risk premium is warranted. *Id.* at 51. He testified that a risk premium between the 50th and 75th percentile (i.e., the third quartile) of the rolling 5-year average risk premiums would be appropriate in the current market. *Id.* The third quartile would be for the observations that are equal to or above the 50th percentile observation, and equal to or below the 75th percentile. *Id.* Based on Mr. Walters'
analysis, the average of the third quartile represents a reasonable risk premium and therefore a risk premium over Treasury yields of 5.93% is justified. Id.

Mr. Walters explained that adding this risk premium to the projected Treasury yield of 3.70% produces an ROE of 9.63%. Id. He also showed that when a similar methodology as described above is applied, the average of the third quartile produces an equity risk premium of 4.53%. Id.

Mr. Walters testified that adding this risk premium to the 13-week A-rated utility bond yield of 5.25% ending April 7, 2023, yields a 9.78% cost of equity. Id. Adding this risk premium to the 13-week Baa-rated utility bond yield of 5.53% for the same period comes out to 10.06%. Id. Adding this risk premium to the 26-week A-rated utility bond yield of 5.43% ending April 7, 2023, produces an estimated cost of equity of 9.96%. Id. at 52. Adding this risk premium to the 26-week Baa-rated utility bond yield of 5.72% for the same period, produces an estimated cost of equity of 10.25%. Id.

Based on these results, Mr. Walters concluded, that a reasonable ROE based on his risk premium analyses is 9.80%. Id.

CAPM

Mr. Walters’ last study was a CAPM. As Mr. Walters explained, the CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. Id. at 52-53. The beta in the equation represents the stock-specific risk that cannot be reduced through diversification. Id. at 53. In a well-diversified portfolio, specific risks related to individual stocks can be reduced by balancing the portfolio with securities that offset the impact of firm-specific factors, such as business cycle, competition, product mix, and production limitations. Id.

In contrast, CUB/PCR/City explain non-diversifiable risks are related to market conditions and are referred to as systematic risks. Id. These risks cannot be reduced through diversification and are considered market risks. Id. Conversely, non-systematic risks, also known as business risks, can be reduced through diversification. Id. According to the CAPM, the market does not compensate investors for taking on risks that can be diversified away. Id. Thus, investors are only compensated for taking on systematic, or non-diversifiable, risks. Id. Beta is a measure of these systematic risks. Id.

The CAPM requires an estimate of the market risk-free rate, the company’s beta, and the market risk premium. Mr. Walters used Blue Chip Financial Forecasts’ projected 30-year Treasury bond yield of 3.70% for his CAPM analysis because long-term Treasury bonds are considered to have negligible credit risk. Id. at 54. Mr. Walters used the Proxy Group’s current average Value Line beta of 0.86, the proxy group’s historical average Value Line beta of 0.74, and the proxy group’s current MI beta of 0.72. Id. at 55. For the market risk premium, in addition to considering the normalized market risk premium of 6.00% with the normalized risk-free rate of 3.87% as recommended by Kroll, Mr. Walters also derived estimates via two approaches: market risk premium and DCF. Id. at 55-56. Mr. Walters derived his market risk premium estimate from the expected return on the market using S&P 500 data, adjusted for inflation, resulting in an 11.71% expected return and ultimately an 8.01% risk premium after subtracting the risk-free rate. Id. at 56-57.
For the DCF approach, Mr. Walters employed two versions of the constant growth DCF model. His first version used the FERC method of estimating the expected return on a market by performing a constant growth DCF analysis on each of the dividend paying companies of the S&P 500 index. \textit{Id.} at 57. The growth rate component is based on the average of the growth projections excluding companies with growth rates that were negative or greater than 20%. \textit{Id.} The weighted average growth rate for the remaining companies is 8.70%. \textit{Id.} After reflecting the FERC prescribed method of adjusting the dividend yield, the weighted average expected dividend yield is 2.09%. \textit{Id.} at 57-58. Thus, the DCF-derived expected return on the market is the sum of those two components, or 10.79%. \textit{Id.} at 58. The market risk premium then is the expected market return of 10.79% less the projected risk-free rate of 3.70%, or approximately 7.10%. \textit{Id.}

The second DCF-based market risk premium estimate was derived by performing the same DCF analysis described above, except using all companies in the S&P 500 index rather than just the dividend paying companies. \textit{Id.} The weighted average growth rate for these companies is 9.70%. \textit{Id.} After reflecting the FERC-prescribed method of adjusting the dividend yield the weighted average expected dividend yield is 1.68%. \textit{Id.} at 58. Thus, the DCF-derived expected return on the market is the sum of those two components, or 11.38%. \textit{Id.} The market risk premium then is the expected market return of 11.38% less the projected risk-free rate of 3.70%, or approximately 7.70%. \textit{Id.} The average expected market return based on the DCF model is 11.09%, and the market risk premium averaging the two DCF estimates is 7.40%. \textit{Id.} Mr. Walters also observed that his average expected market return of 10.89% exceeds long-term market expectations of several financial institutions. \textit{Id.} For these reasons, his expected market returns, and the associated market risk premiums, should be considered reasonable, if not high-end estimates. \textit{Id.} at 59.

Further, Mr. Walters observed that his risk premium estimates range from 6.00% to 8.01%. \textit{Id.} The Kroll analysis indicates a market risk premium between 6.00% and 7.46%. \textit{Id.} Kroll utilizes multiple methods to determine its estimates, including its own analysis that results in an implied return on the market of 9.87%. \textit{Id.} at 60-61. Mr. Walters' results from his various CAPM analyses are shown in CUB/PCR Ex. 1.15.

Reviewing the results of his CAPM analyses lead him to an ultimate CAPM return estimate of 9.40%. \textit{Id.} at 62.

**Response to Staff’s Cost of Common Equity Analysis**

CUB/PCR/City argue that while they find Staff’s proposed ROE of 9.83% to be inflated, they still consider it significantly more reasonable than the Companies’ recommendation. CUB/PCR/City found the most significant flaw in Staff witness Ms. Kight-Garlichs’ proposal to be her expected market return and ultimately her market risk premium of 8.46% in her CAPM model. CUB/PCR Ex. 2.0 at 10. CUB/PCR/City consider this market risk premium excessive because they believe it ignores the substantial body of empirical evidence that demonstrates that an appropriate market risk premium is between 5% and 8%. \textit{Id.} at 10.

CUB/PCR/City add that substituting CUB/PCR/City witness Walters’ DCF average market risk premium of 7.40% from his CAPM model into Ms. Kight-Garlichs’ CAPM creates a result of 10.11%. Substituting this number into her overall equation for
determining a reasonable ROE for the Companies has a result of 9.40%. See Staff Ex. 3.0 at 25-27. CUB/PCR/City contend this outcome illustrates that Ms. Kight-Garlisch’s analysis, when inputs CUB/PCR/City consider reasonable are used, provides support for a rate even lower than Mr. Walters’ midpoint.

Response to the Companies’ Cost of Common Equity Analysis

CUB/PCR/City consider Companies witness Bulkley’s recommended ROE of 9.9% for both North Shore and Peoples Gas overstated and unreasonable. CUB/PCR/City argue the Companies’ current authorized ROEs have supported their finances and attracted investment for years. CUB/PCR/City contend there is no disputing that the Companies have been remarkably profitable with their current ratemaking ROEs in place. Yet the Companies now insist that their financial health and ability to attract capital are in danger unless the Commission approves higher rates to fund larger margins for their shareholders.

CUB/PCR/City argue context from other jurisdictions only further underscores the unreasonableness of the Companies’ request. ROEs for gas utilities have trended downward and the average remains well below 10.0%. CUB/PCR Ex. 1.0 at 3-4: Fig. CCW-1. CUB/PCR/City contend an ROE of 9.9% far surpasses average authorized ROEs; since 2016, the majority of authorized ROEs for natural gas utilities have been below 9.7% with many below 9.5%. Id. at 4-5. CUB/PCR/City conclude the Companies’ proposed ROE of 9.9% is well in excess of the current market ROEs for regulated gas utilities, for regulated utilities in general, and for the Companies in particular. CUB/PCR/City argue it is significantly inflated and, while certainly a benefit to shareholders, creates an unnecessary, unacceptable, and unjust burden on ratepayers.

DCF

Constant Growth DCF

CUB/PCR/City note that the Companies utilized only one form of DCF model, a single-stage constant growth model. The Companies utilized three growth rates, the minimum, mean, and maximum for the Proxy Group, or 5.53%, 6.47%, and 7.61%, respectively. Id. at 67. CUB/PCR/City assert this means Ms. Bulkley relied on growth rates that ranged from 38.35% to 90.25%, higher than the expected 4.00% growth rate of the US economy. Id. Unlike Mr. Walters, Ms. Bulkley chose not to adjust for this growth rate, which Mr. Walters considered unrealistically high. Id. Therefore, CUB/PCR/City argue her DCF model produces unreasonable high-end results.

CAPM and ECAPM

Market Risk Premiums

CUB/PCR/City state that, even though Ms. Bulkley expressed little faith in the use of a DCF model as it applies to her proxy group, it was the only method she utilized to determine her rate of return for her CAPM and ECAPM models. Id. at 70. Ms. Bulkley’s DCF-derived market risk premiums are based on a market return of approximately 12.64%, which consists of a weighted average growth rate component of 10.81% and weighted expected dividend yield of approximately 1.74%. Id. at 69. CUB/PCR/City contend Ms. Bulkley’s sustainable market growth rate of 10.81% is far too high to be a rational outlook for sustainable long-term market growth. Id. This growth rate is nearly
three times the growth rate of the U.S. GDP long-term growth outlook of 4.00%.  *Id.* Of the 405 growth rates ultimately relied on by Ms. Bulkley, 279 are 8.0% or higher, which is twice the projected growth of the U.S. economy. *Id.* CUB/PCR/City conclude it is unreasonable to believe an individual company can sustain growth rates as high as Ms. Bulkley has into perpetuity. As such, CUB/PCR/City argue Ms. Bulkley’s CAPM and ECAPM results should be rejected.

**ECAPM**

*Adjusted Betas*

CUB/PCR/City take issue with Ms. Bulkley’s use of an adjusted Value Line beta in her ECAPM analysis, stating it is inconsistent with the academic research and literature on ECAPM studies. *Id.* at 72. CUB/PCR/City argue the weighting adjustments applied in the ECAPM are mathematically the same as adjusting beta since the inputs are all multiplicative. *Id.* Thus, the end result of using the Value Line adjusted betas in the ECAPM is essentially an expected return line that has been flattened by two duplicative adjustments. *Id.*

In other words, the vertical intercept has been raised twice and the security market line has been flattened twice: once through the adjustments Value Line made to the raw beta, and again by weighting the risk-adjusted market risk premium as Ms. Bulkley has done. *Id.* Moreover, Ms. Bulkley further increases the intercept and flattens the security market line by using projected long-term Treasury yields. *Id.*

The ECAPM will raise the intercept point of the security market line and flatten the slope. *Id.* Again, this has the effect of increasing CAPM return estimates for companies with betas less than 1 and decreasing the CAPM return estimates for companies with betas greater than 1. *Id.* at 73. Mr. Walters modeled the expected return line resulting from the application of the various form of the CAPM/ECAPM in his testimony and he demonstrated in his testimony that the CAPM using a Value Line beta compared to the CAPM using an unadjusted beta shows that the Value Line beta raises the intercept point and flattens the slope of the security market line. *Id.* at 74, 73: Fig. CCW-6. CUB/PCR/City argue Mr. Walters’ testimony shows that the ECAPM adjustment has a very similar impact on the expected return line as a Value Line beta. *Id.* at 74.

CUB/PCR/City contend there is simply no legitimate basis to use an adjusted beta within an ECAPM because it unjustifiably alters the security market line and materially inflates a CAPM return for a company with a beta less than 1. *Id.* As such, CUB/PCR/City argue Ms. Bulkley’s use of an adjusted beta in her ECAPM should be rejected. They note that Staff witness Kight-Garlisch echoed the same criticisms as Mr. Walters regarding the ECAPM. Staff Ex. 3.0 at 37.

CUB/PCR/City further note that in another rate case proceeding, Docket No. 11-0767, the Commission found the use of adjusted betas in the ECAPM was inappropriate. Further, the Commission noted that Staff’s witness explained that by using adjusted betas, the traditional CAPM was already effectively transformed into an ECAPM and therefore, including an additional beta adjustment in the ECAPM model would result in inflated estimates of the samples’ cost of common equity in that proceeding.  *Ill.-Am. Water Co.,* Docket No. 11-0767, Order at 109 (Sept. 19, 2012).
CUB/PCR/City argue the unreasonableness of Ms. Bulkley’s application of the ECAPM while using adjusted betas is clear when looking at the results of her analysis, with a range from 10.97% to 11.73%. PGL Ex. 4.0 at 44; NS Ex. 4.0 at 44. The average authorized ROE for gas utilities has not been at 11% since the year 2003 when the average 30-year Treasury yield was 4.96%, or approximately 126 basis points higher than the projected 30-year Treasury relied on by Mr. Walters. CUB/PCR Ex. 1.10. For the reasons explained above, CUB/PCR/City conclude the ECAPM, as employed by Ms. Bulkley, should be rejected in its entirety.

**CAPM, ECAPM, and Risk Premium**

**Long-Term Projected Interest Rates**

CUB/PCR/City state that to determine her equity risk premiums, Ms. Bulkley relied on long-term projected interest rates, which is problematic. She constructed a risk premium return on equity estimate based on the premise that equity risk premiums are inversely related to interest rates and uses that premise to run a regression analysis. CUB/PCR Ex. 1.0 at 75. Ms. Bulkley contended that there is a simplistic inverse relationship between equity risk premiums and interest rates without any regard to differences in investment risk. *Id.* at 76. However, as Mr. Walters testified, while interest rates certainly are a relevant factor in assessing current market equity risk premiums, the risk premium ties more specifically to the market’s perception of investment risk of debt and equity securities, and not simply changes in interest rates. *Id.* Further, CUB/PCR/City argue Ms. Bulkley’s reliance on long-term projected interest rates introduces a significant level of uncertainty and should be viewed with skepticism. *Id.*

CUB/PCR/City note because the returns on equity Ms. Bulkley used are authorized by commissions, those returns on equity are not directly adjusted by market forces. *Id.* Rather, authorized returns on equity are adjusted by commission policy and regulatory practices, including settled or negotiated outcomes. *Id.* at 76-77. In contrast, interest rates or bond yields are controlled entirely by market forces. *Id.* at 77. CUB/PCR/City consider this significant because regulatory commissions rely on policies and requirements to change authorized returns on equity based on more factors than changes in capital market costs. *Id.* CUB/PCR/City argue Ms. Bulkley’s regression study fails to reflect this rejection of a causal relationship between returns on equity and changes in bond yields. For the reasons above, CUB/PCR/City argue her models should be rejected for their reliance on uncertain long-term interest rates.

e. **PIOs’ Position**

In light of the affordability impacts of Peoples Gas’ proposals in this rate case, PIO state that they do not support Peoples Gas’ proposed 9.9% ROE. PIO recommend the Commission adopt a lower return on equity supported by the record.

f. **AARP’s Position**

AARP states that based upon the returns allowed and experienced by natural gas utilities in other jurisdictions, Peoples Gas’ request for permission to earn a 9.9% ROE is excessive. AARP argues that a significantly lower ROE would be more consistent with the level of business risk faced by companies like NS and PGL, as recently found by other regulatory commissions in other jurisdictions. In addition, Peoples Gas does not need a
corporate profit of near 10% in order to attract capital to make necessary investments. AARP believes that the Commission should not approve any ROE higher than 9.5%, as supported by CUB/PCR/City, which is a level that is more in line with market expectations in this region.

**g. Commission Analysis and Conclusion**

The Companies propose a 9.90% ROE using DCF, CAPM, ECAPM, and bond yield plus risk premium models. Staff proposes a 9.83% ROE using DCF and CAPM models. CUB/PCR/City proposes a 9.50% ROE using DCF, CAPM, and risk premium models. The AG and AARP support the ROE presented by CUB/PCR/City. PIO argues that the Companies' recommended 9.9% is too high.

The Commission must consider all the competing interests in making an ROE determination. “An authorized ROE that is too low restricts the utility’s access to capital at a reasonable cost. Conversely, an ROE that is too high will result in rates that are neither just nor reasonable.”  *N. Shore Gas Co.*, Docket No. 20-0810, Order at 85 (Sept. 8, 2021), citing *Bluefield*, 262 U.S. at 692; *Hope*, 320 U.S. at 603.

The Commission finds that the Companies’ DCF analysis employed unsustainable growth rates and average historical stock prices and does not reflect quarterly dividend payments. The Companies used Value Line long-term earnings per share (EPS) rather than dividends per share (DPS). EPS growth rates are generally used in the DCF models as a proxy for DPS growth rates since there are very few analysts’ long-term forecasts of DPS growth. If DPS growth estimates are available, there should be no need to use the proxy for DPS growth. This could lead to upward bias estimate of the investor-required rate of return on common equity. Substituting the Value Line DPS for the Value Line EPS growth decreases the estimates significantly. There also are problems with the historical data used by the Companies in the DCF analysis. According to Staff the use of historical data favors outdated information that the market no longer considers relevant over the most-recently available information. Historical data reflects conditions that may not continue. The Commission has previously rejected DCF analyses that use historical dividend yields, noting its preference for the use of spot (current) common stock prices in the DCF model instead of the use of average prices.  *N. Ill. Gas Co.*, Docket No. 21-0098, Order at 94 (Nov. 18, 2021); *Consumers Ill. Water Co.*, Docket No. 03-0403, Order at 42 (Apr. 13, 2004).

The Companies’ CAPM and ECAPM analyses rely exclusively on betas calculated using weekly returns and include forecasted U.S. Treasury bond yields as a proxy for the risk-free rate. By relying exclusively upon betas calculated using weekly data, the Companies have introduced bias into their CAPM analysis that could have been mitigated by including a beta estimate derived from monthly return intervals. The Commission prefers to rely on a combination of weekly and monthly beta estimates because it reduces unnecessary bias.

The Companies also include forecasted U.S. Treasury bond yields as a proxy for the risk-free rate. The Commission has repeatedly stated its preference for using current observable U.S. Treasury bond yields to estimate the risk-free rate because it is impossible to accurately predict future interest rates. Staff points to a substantial number
of cases to show the Commission’s position on this issue. The Commission sees no reason to reach a different conclusion here.

The Companies improperly apply adjusted beta estimates in their ECAPM analysis. By using adjusted betas in the ECAPM model, the Companies have effectively adjusted twice for the flatness of the empirical security market line (SML) and, thus, inflates the estimate of the sample’s cost of common equity. Staff observes that the Commission has rejected such an application of the ECAPM in several prior proceedings and the Commission rejects it again here.

The Companies also have several flaws in their bond risk premium model analysis. The Commission finds the measurement period for the analysis is completely arbitrary. Also, the returns included are authorized by regulatory bodies and are not necessarily market-based returns but rather are legal determinations. The Commission agrees with Staff that the Commission has repeatedly rejected the use of bond yield plus risk premium models to determine the cost of common equity in several prior proceedings.

The Companies also considered an unwarranted size-based risk premium in the final ROE assessment for North Shore. Staff again states that the Commission has rejected the same type of size-based business risk adjustment in several other dockets. The Commission does not see any basis to reach a different conclusion here.

CUB/PCR/City witness Walters estimated the ROE for the Companies using DCF, CAPM, and risk premium models. This analysis: (a) included average stock prices in his DCF analyses; (b) included a forecasted Treasury bond yield to estimate the risk-free rate in his CAPM analyses; (c) relies exclusively on weekly beta estimates for his CAPM analyses; and (d) relies on a bond yield plus risk premium model, in addition to DCF and CAPM analyses, to estimate the ROE for the Companies. The Commission notes that this analysis has many of the same problems as the Companies’ proposals.

Both Staff and CUB/PCR/City utilized two types of DCF models to estimate the cost of common equity: the constant growth model and the non-constant growth model. Staff and CUB/PCR/City’s non-constant growth DCF estimates are 8.23% and 8.05%, respectively. The Commission observes that these estimates are well over 100 basis points less than both parties’ constant growth DCF estimates. The estimates are also well below any ROE the Commission has approved for a natural gas utility. Neither party attempted to explain the divergence. Therefore, the Commission will not consider the non-constant growth DCF estimates in developing the authorized ROE for the Companies. In so doing, however, the Commission is not foreclosing the use of a properly applied non-constant DCF model in the future, absent unexplained incongruities, as different circumstances may make it useful in developing a just and reasonable authorized return.

The Commission has consistently approved the use of both the DCF model and the CAPM models in determining the cost of common equity. Staff’s ROE analysis is in line with the preferred methods of the Commission and does not suffer from the use of repeatedly rejected adjustments. The Commission notes the CAPM requires a forward-looking market risk premium input that Staff derived by taking its 12.65% forward-looking market return (Rm) estimate minus a risk-free rate (Rf) of 4.19%. The Commission observes that Staff’s 12.65% Rm estimate is significantly higher than the 10.79% Rm
estimate determined using the FERC’s method which, similar to Staff’s method, estimates the forward-looking market return through a constant growth DCF model applied to the dividend-paying companies of the S&P 500. CUB/PCR Ex. 1.0 at 57-58. Staff’s 12.65% Rm estimate is also notably higher than long-term expected market returns published by U.S. financial institutions. See id. at 59. Thus, the Commission finds substituting Staff’s 12.65% Rm estimate with the 10.79% determined from using the FERC’s Rm estimation method results in a more reasonable market risk premium estimate, which in turn results in a revised Staff CAPM estimate of 9.47%. Averaging this revised Staff CAPM estimate of 9.47% with Staff’s constant growth DCF estimate of 9.40%, results in a 9.44% ROE.

Staff proposed the ROE estimate from the DCF and CAPM models be adjusted downward by 6 basis points (or 0.06%) because the risk of the Companies is slightly lower than the overall risk of the Proxy Group used by Staff. Since neither PGL nor NS is publicly traded, a proxy group of similar comparable risk public utilities was used. Staff argues that without the downward adjustment, the common equity estimates for the Companies would be too high. The primary difference between the Companies’ and Staff’s ROE is the downward risk adjustment. The Commission agrees that Staff’s downward risk adjustment is necessary to reflect the lower risk of the Companies in comparison to the risk of the Proxy Group that Staff used. Applying that 6-basis point adjustment to the 9.44% average of Staff’s constant growth DCF and revised CAPM estimates results in a 9.38% ROE.

The Commission finds Staff’s DCF and CAPM models, adjusted as explained above, meet the goals of Hope and Bluefield in allowing the Companies to attract capital yet charge reasonable rates. Therefore, the Commission authorizes an ROE of 9.38%.

5. Overall Rate of Return and Capital Structure

The Commission adopts a 6.96% rate of return on rate base for North Shore. That rate of return is based on Staff’s proposal to adopt North Shore’s actual year-end 2022 capital structure, consisting of 5.40% short-term debt, 42.02% long-term debt, and 52.58% common equity, and the costs of the individual components discussed above.

The Commission adopts a 6.65% rate of return on rate base for Peoples Gas. That rate of return is based on Staff’s proposal to adopt Peoples Gas’ actual year-end 2022 capital structure, consisting of 2.95% short-term debt, 46.26% long-term debt, and 50.79% common equity, and the costs of the individual components discussed above.

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VIII. COST OF SERVICE AND ALLOCATION ISSUES

A. Uncontested Issues

1. Proposed Allocations

The Companies’ proposed allocations of production costs, storage costs, transmission costs, general and intangible plant, and taxes are undisputed and are approved.

2. Future Rate Proceeding Filing Requirements

Staff witness Moushon did not propose adjusting the Companies’ embedded cost of service studies (“ECOSSs”), but recommended that the Commission require the Companies to submit in their next general rate proceedings an ECOSS that includes one or more rate classes for low-income qualifying customers (“LIQC”). Mr. Nelson, however, explained that he is not aware of any cost-based facts that would support creating LIQC classes in an ECOSS. NS-PGL Ex. 16.0 at 3. Mr. Moushon later withdrew the position that a separate ECOSS is needed for low-income customers. Staff Ex. 14.0 at 12. Accordingly, the Commission finds that this issue is no longer contested.

B. Contested Issues

1. Embedded Cost of Service Study

a. Companies’ Position

The Companies argue that the standard for evaluating the Companies’ ECOSSs is whether they are just and reasonable. BPI 1, 146 Ill.2d at 208; Docket Nos. 11-0280/0281 (cons.), Order at 165 (Jan. 10, 2012), (“The Utilities' ECOSSs are complete,
they systematically functionalize, classify and allocate costs, and they comport with the cost causation principles for preparing such studies that the Commission has approved in many other rate cases."). Testimony from Companies witness Nelson and Staff witness Harden shows they are. As Mr. Nelson explained, the EC OSSs employ well-established methods centered around the principle of cost causation. The Companies note that Staff explained that the studies are reasonable because they are consistent with principles of cost causation, follow guidelines set forth in the NARUC Gas Manual, and use methods that the Commission has previously approved.

In contrast, intervenors’ challenges are largely aimed at setting the customer charge as low as possible. Intervenors find the “basic customer method” attractive because (at least under their applications of it) it accomplishes this goal. However, their results-driven approaches fall short of reasonable methodologies, fail to consider many realities of utility service, and depart from methods the Commission has approved—as the Companies explained in their initial brief (NS-PGL IB at 176–179) and Section VIII.B.1.a. (“Classification of Distribution Costs”) below. More to the point, their objections do not disprove the reasonableness of the Companies’ cost of service studies.

ELPC alternatively argues that if the Commission does not fully adopt the basic customer method, it should nevertheless require the Company in future rate cases to conduct an EC OSS based on this approach and use it as a starting point for rate design. ELPC IB at 18. ELPC argues that the Wisconsin and Michigan commissions have relied on multiple EC OSSs to inform various decisions. ELPC IB at 18–19. The Companies opine that relying on this particular approach would not be fruitful.

The Companies dispute the City’s assertion that A&G costs should be treated as non-customer costs that vary with changes in demand. COC Ex. 2.0 at 34. The Companies assert that A&G costs are incurred in the general administration of the business and cannot be readily assigned to utility functions or classifications. NS-PGL Ex. 16.0 at 16. Therefore, these costs are generally apportioned using a composite allocation of other direct costs. Id. at 15.

The Companies state that they allocated labor-related A&G expenses based upon the allocated results of the labor portion of O&M expenses. Plant-related A&G expenses were allocated based upon the allocated results of net plant in service. General O&M-related A&G expenses were allocated based upon the allocated results of all other total O&M expenses, excluding A&G expenses. NS Ex. 6.0 REV at 20; PGL Ex. 6.0 REV at 23. The Companies assert that this treatment of A&G costs is consistent with guidance provided by the American Gas Association Gas Rate Fundamentals text, the NARUC Gas Manual, and the NARUC Electric Utility Cost Allocation Manual. NS-PGL Ex. 16.0 at 16–17.

b. Staff’s Position

The Commission should approve both North Shore’s and Peoples Gas’ EC OSSs, as recommended by Staff. The EC OSSs show the distribution of revenue responsibility by customer class, necessary to achieve equalized rates of return on investment for the proposed revenue requirements. Staff Ex. 5.0 at 4. Staff explains that the EC OSSs identify the revenues, costs, profitability for each class of service and are used in the development of the Companies’ proposed cost-based rates. Generally, the EC OSS
utilize three major steps: (1) functionalization; (2) classification; and (3) allocation of all the costs of the utility’s system to customer classes. *Id.* at 4-5. The Companies explained that the most important theoretical principle underlying an ECOSS is that cost incidence should follow historical embedded cost causation. *Id.* at 5. The costs that customers are responsible to pay should be those costs the customers cause the utility to incur because of the characteristics of the customers’ usage of utility service. *Id.*

North Shore used the same model for its ECOSS as presented in its last rate case, Docket No. 20-0810. Staff Ex. 5.0 at 5. Staff compared the current ECOSS and the one provided in North Shore’s last rate case and found the studies to be very similar and consistent with one another; therefore, Staff did not object to North Shore’s ECOSS being used as a guidance tool for setting rates in this proceeding. *Id.* at 6.

Staff notes that Peoples Gas’ ECOSS did not use the same model it used in Peoples Gas’ last rate case, Docket No. 14-0225. *Id.* The Company integrated its legacy Excel-based COS model into a new software platform, Utilities International, Inc. d/b/a UI Solutions Group. *Id.* The Company stated that the change enables the Company to leverage similarities in methodologies, calculations, and reporting across all of the WEC Energy Group utilities. *Id.* The Company also stated that the software changes how the expenses are displayed in the ECOSS and simplifies some allocation factors. *Id.* Peoples Gas’ proposed ECOSS is the same model that was presented by North Shore in North Shore’s last rate case, Docket No. 20-0810. Staff Ex. 5.0 at 7.

Staff urges the Commission to approve North Shore’s and Peoples Gas’ ECOSSs. It is Staff’s opinion they are consistent with principles of cost causation, are approved ECOSSs in previous rate cases, and follow guidelines set forth in the NARUC Gas Manual. Staff witness Harden addresses PIO witness Cebulko’s and City witness Rábago’s recommendations regarding the ECOSSs below.

City witness Rábago recommended that Peoples Gas’ ECOSS implement a “basic customer” method for developing its fixed customer charge. Staff Ex. 13.0 at 4. He opines that the least cost to provide minimum service should be the method to classify customer-related costs, which would then reduce fixed customer charges that result from an alternate ECOSS study. *Id.* Staff witness Harden recommends rejecting the City’s recommendation for an alternate ECOSS study. *Id.* Staff witness Harden continues to recommend that the fixed customer charges be based on the ECOSSs submitted with these rate case filings as they are consistent with cost causation principles and were approved in North Shore’s previous rate cases. *Id.*

PIO witness Cebulko calculated his proposed fixed customer charge based on the “basic customer” approach to incentivize customer behavior that is aligned with certain state policy goals. *Id.* at 7. He asserted that his proposal for the “basic customer” approach to the ECOSS better reflects cost causation. Staff disagrees. Staff witness Harden notes that per the NARUC Gas Manual, utility ratemaking and rate design is more art than science with ample judgment that can reflect the final result. Staff continues to recommend that the Companies’ rate design be based on the ECOSSs submitted with these rate case filings, which result in acceptable cost-based rates rather than the adjustments recommended by PIO. *Id.*
It is Staff’s opinion that the Companies’ ECOSs are acceptable guidance tools for setting rates in this docket and should be approved by the Commission in this proceeding. They are consistent with principles of cost causation, are approved ECOSs in the North Shore previous rate case, and follow guidelines set forth in the NARUC Gas Manual. COC Cross Ex. 3. Staff witness Harden has emphasized that ECOSs provide data that serve as a starting point for the Companies rate design proposals, rather than an exact blueprint that must be precisely followed. COC Cross Ex. 5.

c. AG’s Position

See AG’s position under Residential Rate Design- X. C. 1.

d. City’s Position

The City affirms that a utility’s ECOS plays a major role in establishing the analytical support for proposed rates and is a key element in both the Commission’s and Staff’s evaluation of proposed rates. Therefore, the City urges the Commission to reject both PGL’s ECOS and PGL’s proposals to increase its fixed customer charges based on that ECOS because PGL’s ECOS and fixed customer charge rate designs are contrary to well-established rate design principles and do not follow the Commission’s direction to PGL in its last rate case. PGL’s last rate case was filed in 2014. The Commission’s Final Order in that rate case was issued on January 21, 2015; the City refers to that Final Order as the “2015 Order.”

It is the City’s position that there is no doubt that PGL conducted an ECOS; there also is no doubt that an ECOS could be used as a “guide for the development” of rates, as PGL states. PGL IB at 175. The City notes that the purpose of an ECOS is to be a guide for development of rates. This point is described in the NARUC Gas Distribution Manual. Nat’l Assoc. of Regulatory Utility Commissioners, “Gas Distribution Rate Design Manual,” (June 1989), referred to herein as “the NARUC Manual” and cited at AG Ex. 8.01. PGL relied upon this document in its testimony regarding how it conducted its ECOS. See, e.g., NS-PGL Ex. 16.0 at 8, fn.3. However, given the Commission’s rate design policies stated in its 2015 Order in the 2014 Rate Case, the City asserts that the question now is whether PGL’s ECOS should be used as the determination of the amount of fixed customer charges in this rate case.

It is the City’s position that PGL’s ECOS does not serve as a reasonable basis for review or approval of PGL’s proposed rates, or even as guidance in evaluating those rate proposals. The City is contesting PGL’s ECOS and proposals to increase the monthly customer charge in Service Classifications (“S.C.”) 1, 2, and 4. The City focuses its discussion of defects in PGL’s ECOS and their effects on S.C.1 residential customers who are the vast majority of PGL’s customers.

The City notes that PGL’s increased fixed customer charges must be paid each and every month by each and every PGL customer, regardless of whether they use any gas whatsoever. The City asserts that PGL subverts the 2015 Order because its ECOS improperly classifies costs, and because PGL uses that improperly prepared ECOS to create fixed customer charges that are inflated, regressive, and contrary to the Commission’s rate design principles.
It is the City’s position that PGL’s ECOSS should not be accepted as the basis for determination of the fixed customer charge for two principal reasons. First, because of the judgments PGL made when it conducted its ECOSS, the City believes that study’s use for setting the fixed customer charge undermines the Commission’s important rate design policies. Second, the City highlights that PGL’s ECOSS was conducted behind the shield of a private licensing agreement, using inaccessible computer software, so that precisely how PGL made the judgments it did and how those judgments could be adjusted to meet the Commission’s rate design policy are inaccessible to the Commission, Staff, and all intervenors. These two fatal flaws require that PGL’s ECOSS be rejected as a basis for rate design in this case.

e. ELPC’s Position

ELPC argues that even if the Commission does not fully adopt the basic customer method recommended in this proceeding, the NARUC Gas Manual points out that it may use that method “as a starting point for rate design.” NARUC Gas Manual at 20. ELPC states that the Commission should require the Company to conduct an ECOSS pursuant to the basic customer approach in future proceedings. ELPC points out that other Commissions in other Midwestern states have required gas utilities to conduct multiple cost of service studies to inform rate design. For example, the Public Service Commission of Wisconsin and the Michigan Public Service Commission required utilities to provide ECOSS pursuant to this method. ELPC argues that it will help to develop the cost allocation methodology to determine costs and an appropriate customer charge. ELPC IB at 18–19.

f. Commission Analysis and Conclusion

The Commission notes that both the Companies and Staff support the ECOSSs filed for Peoples Gas and North Shore. The Companies state that the Companies’ ECOSSs are just and reasonable. The Companies claim that the studies are reasonable because they are centered around cost causation. Staff states that the Companies’ ECOSSs identify the revenues, costs, profitability for each class of service and are used in the development of the Companies’ proposed cost-based rates. Staff further states that the studies are reasonable because they are consistent with principles of cost causation, follow guidelines set forth in the NARUC Gas Manual, and use methods that the Commission has previously approved. The Commission agrees with Staff and the Companies that the Companies’ ECOSSs are reasonable and are consistent with the principles of cost causation and are therefore approved.

The City notes that the Companies generate their ECOSS based on a proprietary licensed software platform provided by Utilities International, Inc. d/b/a UI Solutions Group (“the Proprietary Software”), to which no party has access. COC Ex. 4.01, 4.02. The Companies provide the Commission and all parties a summary of the ECOSS’s output, which does not show the data sets, formulae, or logic of the software’s operation. Cf. PGL Ex. 6.1 through Ex. 6.9; COC Ex. 4.0 at 2-4. The Companies stated that it would not be possible to provide a spreadsheet of ECOSS results with links and formulae intact, as the City had requested, because the City would need to have arranged and paid for access to the Proprietary Software. COC Ex. 4.01.
It is the Companies’ choice to use the Proprietary Software but that does not shield the generated ECOSS from examination by Staff and parties. In any future rate case involving Proprietary Software, the utilities should take appropriate steps to ensure all parties have access to the inputs, logic, and formulae used to produce the cost allocations from the Company’s ECOSS, in sufficient detail to enable parties to replicate or validate those results.

Staff shall work with the Companies and intervenors to establish appropriate procedures to protect the proprietary aspects of the ECOSS.

2. Classification of Distribution Costs
   a. Companies Position

   The Companies explain that the distribution system must connect to all customers and handle peak demand. The costs of connecting customers should be classified as customer-related, because even if a customer uses little to no natural gas, there are costs associated with serving each customer. The remaining costs should be classified as demand-related.

   City witness Rábago recommended directing Peoples Gas to adopt a different method for developing its fixed customer charges: the “basic customer method.” NS-PGL Ex. 16.0 at 4. Mr. Rábago also recommended that Peoples Gas modify its ECOSS to remove demand-related costs from the customer cost classification. Id. ELPC also recommended using the “basic customer method.”

   The Companies contend that the “basic customer method” should be rejected. PGL’s classification of distribution costs is supported by industry guidance and past practice. Intervenors’ goal, on the other hand, is simply to set the customer charge as low as possible.

   As Mr. Nelson explained, the “basic customer method” misses a fundamental point: service lines, house regulators, and metering assets are all necessary to connect a customer to PGL’s system. The costs to install these assets do not change with fluctuations in usage. NS-PGL IB at 178–179; NS-PGL Ex. 16.0 at 8. Nor do the costs to replace them. NS-PGL Ex. 16.0 at 8. So, it would not make sense to classify them as demand-related.

   The “basic customer method” is also unreasonable because it requires a subjective assessment of what kind of installation is the “most basic” way to connect a customer. Intervenors assert that the “basic customer method” limits customer-related costs to those that vary directly with the number of customers on the system. ELPC IB at 17; COC IB at 34, 53. The Companies state, however, it simply is not true. There are many variables involved in connecting different customers to the Companies’ systems. NS-PGL IB at 179. Subjective assessments about the “most basic” installation may lead to inaccurate results. And costs associated with assets in excess of the most basic may still be customer costs. NS-PGL Ex. 16.0 at 6.

   The City’s position is that the fixed customer charge should be limited to the marginal cost to connect a customer to the system. Id. at 6. However, ECOSSs do not present marginal costs. Id. at 7, 8. While a particular asset’s embedded cost may have represented a marginal cost at a specific point in history, it is unlikely that a service line
installed before 1940 reflects the cost to connect a customer to People Gas’ system today. \textit{Id.} at 8.

Intervenors have attempted to characterize PGL’s classification of various costs as inconsistent with the Commission’s Order in the Companies’ test year 2015 rate case. See, \textit{e.g.}, COC IB at 35–36. The City even goes so far as to claim that PGL’s classification “skirt[s] around the language and intent of the Commission’s 2015 Order.” \textit{Id.} at 36. The City recognizes that the Commission’s Order did not say anything about PGL’s classification of the fixed costs that intervenors assert are demand-related. \textit{Id.} As Staff has found and as the Companies have explained, PGL proposes recovering only the customer-related costs through its fixed customer charge, which is consistent with the Commission’s order in the Companies’ 2015 rate case. Staff IB at 120.

PIO witness Cebulko challenged Peoples Gas’ classification of distribution costs for an independent reason. Mr. Cebulko claimed that Peoples Gas’ classification of service line costs is improperly motivated by a desire to increase customer charges. PIO Ex. 1.0 at 105. Contrary to Mr. Cebulko’s assertions, Peoples Gas has a longstanding practice of carefully analyzing and assigning costs. NS-PGL Ex. 16.0 at 9. The methods it uses are consistent with industry guidance and past practice and make sense. The Companies’ classification of distribution costs is supported and should be accepted.

\textbf{b. City’s Position}

The City agrees with PGL that for a properly performed ECOSS, after sorting costs according to function, \textit{i.e.}, production, storage, transmission, and distribution, the ECOSS is required to take PGL’s non-storage distribution costs and classify them by whether they are commodity-related, demand-related, or customer-related. PGL Ex. 6.0 REV at 6, 7. The City also agrees with PGL that the costs in each classification are respectively chosen by whether they are driven by level and timing of loads (demand costs), number of customers (customer costs), or gas throughput (commodity costs). PGL Ex. 6.0 REV 7; COC Ex. 2.0 at 17. The City further agrees with PGL that customer costs are costs that vary exclusively or almost exclusively with the number of customers that connect to the gas system. PGL Ex. 6.0 REV at 7; COC Ex. 2.0 at 17. The City notes that the NARUC Manual defines “customer costs” as “those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied.” AG Ex. 8.01 at 32. In contrast, the NARUC Manual states that “demand costs . . . vary with the quantity or size of plant or equipment.” \textit{Id.} at 33; \textit{see also} COC Ex. 2.0 at 34.

City witness Rábago explained that “customer costs” should be developed thoughtfully by identifying “the smallest portion of the incremental costs to connect the customer to the system as a customer.” COC Ex. 2.0 at 1-3, 17, 33. Mr. Rábago explained that this careful approach to classifying customer costs to avoid counting demand-related costs is referred to as the “basic customer method” and implements the rate design principles endorsed by the Commission in its 2015 Order. \textit{Id.} at 12-13; 33; 35.

The City emphasizes that the Commission set forth its fixed customer charge rate design principles in the 2014 Rate Case. As shown in the 2015 Order from that rate case, PGL openly sought to base its fixed customer charge on both demand-related costs and
costs that it called “customer costs.” 2015 Order at 158-159. The City showed that, according to the 2015 Order, PGL’s theory was that, because its self-selected demand costs and customer costs were, from an accounting perspective, “fixed” costs, meaning long-lived, it should recover all of those costs via a fixed customer charge. Id. The City notes that, in the 2014 Rate Case, PGL was clear that its intent was to increase the customer charge to recover as much of its “fixed costs” as possible, including by having its 2014 proposed costumer charge based on costs its ECOSS classified as customer costs and costs its ECOSS classified as demand costs. See id. at 158-159, 173-176.

The City states that in the 2014 Rate Case, the Commission rejected PGL’s approach, ruling that the fixed customer charge should only recover customer costs and that the fixed customer charge should not be based on demand-related costs. Id. at 173-176.

The City further explains that, to remedy PGL’s attempt to unjustifiably increase the percentage of its distribution costs collected as a fixed customer charge, in 2015, the Commission ordered that PGL use the “more conservative rate design proposed by Staff,” whereby, for purposes of S.C.1 in particular, fixed customer charges would recover only the costs which PGL’s ECOSS classified as “customer costs,” and PGL would recover the remaining non-storage distribution costs as volumetric, i.e., per-therm used, charges. 2015 Order at 176, 182.

The City highlights that at the time of the 2014 Rate Case’s rate design dispute, the focus was on ending PGL’s goal to have almost all of its distribution costs collected through the customer charge. 2015 Order at 173. The City asserts that the intent of the Commission’s 2015 Order was to end PGL’s attempt to recover “non-storage demand-classified distribution costs through a fixed customer charge.

The City notes that, in the 2014 Rate Case, PGL’s classification of demand-related fixed costs as “customer costs” was not specifically raised or disputed in that proceeding. The City asserts that PGL is now relying on the Commission’s silence in its 2015 Order regarding how its ECOSS should classify costs as “customer cost” vs “demand costs” to try to skirt around the language and intent of the Commission’s 2015 Order. The City emphasized that the 2015 Order directed that the fixed customer charge, and, therefore, the ECOSS that produces that charge, should comply 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.” 2015 Order at 176. The City’s position is that the intent of the Commission’s order in 2015 was that PGL was to begin implementing those policies. According to the City, now, for Test Year 2024, PGL is attempting to evade the express direction of the Commission by using its ECOSS to classify a wide range of demand-related costs as “customer costs” and then using that inflated collection of “customer costs” to derive fixed customer charges.

The City argues that PGL’s ECOSS’s exaggeration of its “customer costs” through inclusion of demand-related costs is confirmed by PGL’s own direct testimony. The City points to the testimony of PGL witness Nelson, who defined what PGL believes are “customer-related” costs: “costs associated with customers regardless of the amount of natural gas they demand or consume.” PGL Ex. 6.0 REV at 7. The City avers that, by defining “customer costs” as costs “associated with customers,” PGL is taking a
subjective and broad view of “customer costs” that is unlimited in scope and provides no
distinction between demand versus customer costs, as those classifications are typically
made. The City further finds that, using the broad “associated with” concept, Mr. Nelson
testifies that “customer-related” costs are “costs incurred to extend service to and attach
a customer to the distribution system, meter any natural gas usage, and maintain, bill, and
service the customer’s account.” Id. at 7. The City’s position is that PGL improperly
classifies all of those “customer-related” costs as “customer costs” even when those costs
vary with the level of customer demand. The City highlights that PGL classifies as
customer costs any system connection costs, as they are incurred for all customers, and
even if those costs “vary with the quantity or size of plant and equipment.” See AG Ex.
8.01 at 33; COC Ex. 2.0 at 17-18.

The City points to PGL testimony which the City asserts shows that PGL
recognizes that its cost of connecting a customer to the gas system varies with the amount
of gas the customer will use. The City notes that PGL regularly operates on the basis
that larger demand drives larger, more expensive services, including pipe, regulators, and
other infrastructure.

The City says that, despite the amount of gas determining the sizing of gas service,
PGL broadly lumps all costs attributed to Service Lines (Plant Account 380) (also called
“services”) as “customer costs.” PGL Ex. 6.0 REV at 16. PGL witness Nelson admits
that costs of service lines vary with demand. Id. at 16. Weighting is used to allocate inter-
class costs, not intra-class costs. The City asserts that Mr. Nelson’s testimony shows
that services-related costs vary with the amount of gas a customer uses or plans to use,
but solely because these costs can be “traced back” to a class of many customers with
varying demands, PGL considers all service line costs as “customer costs” and instructed
its EC OSS to count them as such. The City’s position is, however, that to fulfill the
Commission’s 2015 direction not to include demand-related costs in the fixed customer
charge, the services costs in excess of those associated with the most basic customer
connection should be classified as a demand-related cost and not used to calculate the
fixed customer charge.

The City focuses on service lines because they are the largest dollar category in
PGL’s EC OSS’s reports of “customer costs” for all customer classes. The total Test Year
2024 balance for “services,” which PGL classified as “customer costs” for all customer
classes, is more than $1.4 billion. PGL Sched. E-6. As the City highlights, in “services,”
PGL includes the cost of pipe and other components that provide the functional
connection between the gas main and the customer meter. Mr. Rábago explained that,
depending on the customer, “services” could be as little as a tap on an existing service
and a short section of pipe leading to a meter bar. COC Ex. 2.0 at 36.

Mr. Rábago noted in his direct testimony that the cost data in PGL Schedule E-6
was not presented in enough detail to discern the exact dollars by which PGL was
overstating the cost of “services” in its EC OSS. COC Ex. 2.0 at 36. Mr. Rábago explained
that PGL prepares its EC OSS and rates “at a class level,” averaging a range of costs for
a range of infrastructure components, thereby deviating from cost-based rate design. Mr.
Rábago found that, for example, PGL charges a customer in a multi-dwelling unit building
the same customer charge as a customer at a single-family residence. Mr. Rábago relied
on PGL’s response to data requests to confirm that PGL does not know or attempt to
understand how the cost to serve varies with residence type and/or differences in the level of demand. See id. at 36, fn.91; COC Ex. 2.10; COC Ex.2.11.

Mr. Rábago further showed that information regarding the basic customer charge for providing a service line is available to PGL from its proprietary ECOSS model if it chose to input such information into its ECOSS model. Mr. Rábago also found that PGL includes in “services” costs, additional costs of about $13 million for even larger plastic pipe, and approximately $30 million more in steel pipe. COC Ex. 2.0 at 36. In addition, Mr. Rábago testified that service installation costs also vary by size and length of pipe; the cost of two-inch pipe is nearly 30% higher than the costs of pipe equal to or smaller than 1.25 inches in diameter. COC Ex. 2.0 at 36-37.

The City adds that just as PGL overstates its customer costs for services, PGL does the same for other accounts on the FERC chart of accounts. For example, the City points to PGL witness Nelson’s description of its costs listed on the accounting ledger as “Meters and Meter Connection and Installations, Plant Accounts 381 & 382,” as costs that vary with gas flow demand. PGL Ex. 6.0 REV at 16-17. The City highlights that, despite Mr. Nelson’s description of how meter-related costs vary with demand, PGL instructs its ECOSS to include all meter costs, regardless of size or expense, in the calculation of “customer costs.” COC Ex. 2.0 at 22-23. Mr. Rábago explained that the fact that PGL has data that ties meter costs to classes of customers is not a reason to have its ECOSS treat this group of costs as “customer costs” for purposes of generating the fixed customer charge. Id. Mr. Rábago showed that PGL also misclassifies all costs in its ledger for House Regulators (Plant Account 383), as 100% customer-related (PGL Ex. 6.0 REV at 17), even though this equipment, like meters, vary in cost and size with the quantity of gas demanded by the customer. COC Ex. 2.0 at 23.

The City then contends that PGL’s classification of demand-related gross plant costs are further inflated by cascading effects from accounts related to gross plant that PGL also lumps into “customer costs.” Mr. Rábago found that O&M costs (Account 870-894) are classified based on gross plant in each plant account (PGL Ex. 6.0 REV at 18-19), and because PGL inflates customer costs with all costs for services, meters, and regulators, “customer costs” are further inflated by the distribution O&M expenses associated with gross plant. COC Ex. 2.0 at 23.

Mr. Rábago showed the same over-inclusion of demand-related costs when PGL classified all of its “FERC Uniform System of Accounts (“USOA”) Customer Costs,” which are related to customer accounts, customer service and information, sales, and general and administrative expenses as “costumer costs”. COC Ex. 2.0 at 17; 23-24; see also PGL 285 Filing (Part 1) Section 285.305, subpart d. Mr. Rábago concluded that it would be more proper for PGL to classify customer service costs associated with customer-company interactions, such as billing issues, payment problems, ongoing service problems, efficiency programs, account management, and uncollectibles costs, as demand-related because they are largely costs driven and caused by customer demand for gas service. COC Ex. 2.0 at 23-24. Mr. Rábago showed that PGL concedes that it classifies all customer service and general and administrative expenses as “customer costs,” using various allocation methods. Id.; PGL Ex. 6.0 REV at 20-23.
The City also claims that PGL’s ECOSS should not be accepted by the Commission because PGL has not been open and transparent about how it conducts its ECOSS; specifically, the software, inputs, and algorithms that was used in the ECOSS are not available to the Commission, Staff, or any party to this proceeding for testing or inspection. The City describes that, during the course of discovery in this rate case, the City learned that, in 2017, PGL decided to generate its ECOSS based on a proprietary, privately licensed software to which no other party in this rate case, not even Staff, has access. COC Exs. 4.01, 4.02. Instead, PGL’s ECOSS submission to the Commission and all parties is a summary of the ECOSS’s output, which does not show the data sets, formulae, or logic of the software’s operation. Cf. PGL Ex. 6.1 through Ex. 6.9; COC Ex. 4.0 at 2-4.

The City learned about the inaccessible condition of the ECOSS software after the City and other parties were required to file their direct testimony in this matter, from PGL’s response to a City Data Request (COC 6.43) which had asked for more detailed information regarding the ECOSS calculations than PGL had provided to date. COC Ex. 4.01. PGL stated that it would not be possible to provide a spreadsheet of ECOSS results with links and formulae intact, as the City had requested, because the City would need to have arranged and paid for access to a licensed software platform provided by Utilities International, Inc. d/b/a UI Solutions Group (“the Proprietary Software”). Id. In response to data requests that the City subsequently served regarding this software and data restriction issue, PGL explained that it had begun creating its ECOSS using the Proprietary Software in 2017, but that “this is the first case where Peoples Gas is using Utilities International’s software to develop the ECOSS.” COC Ex. 4.02. PGL stated that it was “willing to conduct ECOSS runs using the ECOSS software on behalf of parties to this proceeding as may be reasonably requested.” COC Ex. 4.03.

Upon learning that it would not be able to examine the PGL ECOSS model by spreadsheet with all cells unlocked and formulae intact, the City, while unable to access more specific knowledge about the ECOSS’s content and inner workings, attempted to simulate what the PGL ECOSS should generate if basic customer method principles for classifying customer costs were used. COC Ex. 4.0 at 3. The City further requested exclusion from the classification of customer costs uncollectible costs, indirect labor costs, and customer service costs unrelated to providing basic service to customers and establishing a basic service account. COC Ex. 4.0 at 57-59.

PGL met with the City’s counsel and Mr. Rábago to discuss, as best Mr. Rábago contended he could verbalize without seeing the inner workings of the ECOSS, directions on how to generate an ECOSS using the basic customer method. COC Ex. 4.0 at 2-4. A few days later, PGL provided a report of the results of what it called an “alternative ECOSS,” in response to the City’s request. COC Group Ex. 4.04. The City asserts that, while not the same as being able to analyze the data sets and algorithms the Proprietary Software has been instructed to deploy, the “Basic Customer Method ECOSS” generated by PGL produced a report (COC Group Ex. 4.04) demonstrating that, as expected, PGL’s ECOSS does not properly classify customer costs without substantial inflation for demand-related costs. A table showing the Results of the Basic Customer Method ECOSS can be found at “COC Table 2: Results of Basic Customer Method” on page 43 of the City’s Corrected Initial Brief and COC Group Ex. 4.04.
The City asserts that the Basic Customer Method ECOSS prepared at Mr. Rábago’s oral direction shows that the percentage of costs recovered by a customer cost per month should be much less than what PGL has proposed. Mr. Rábago further concluded that PGL’s generation of the Basic Customer Method ECOSS within days of Mr. Rábago’s oral descriptions of how to perform that ECOSS demonstrates that PGL has the embedded cost data and software available to perform such a study. COC Ex. 4.0 at 7. PGL did not contradict the City’s description of these events in any surrebuttal testimony or otherwise.

The City points out that PGL admits that “the model [it] use[s] for performing cost of service studies has changed since Peoples Gas’ 2015 Rate Case. The legacy Excel model that was used in Peoples Gas’ 2015 Rate Case was integrated onto a new software platform, Utilities International, Inc. dba UI Solutions Group.” PGL Ex. 6.0 REV at 10-11. PGL further admits that “[i]t is not possible to produce [PGL Schedule E-6 (the ECOSS Study Model Inputs and Results)] spreadsheet with links and formulae intact unless the requesting party has the requisite Utilities International software; the output of the software is a report in excel without links or formulae.” COC 4.01.

Given these facts, the City urges that the Commission reject PGL’s ECOSS because it does not allow full transparency to the Commission, Staff, and parties. The City’s position also is that the Commission should not rely on the PGL “black box” ECOSS as a legitimate basis for fixed customer charge rate design. The City points to the NARUC Manual, which states that embedded in a utility’s ECOSS are “judgments” of that utility. AG Ex. 8.01 at 30. In the City’s view, not only is it important to see exactly how the ECOSS computes cost information, the ECOSS should be open and transparent about the information inputted and excluded and how that information is manipulated by the software, i.e., to fully understand the “judgments” PGL deployed.

In this regard, the City highlights the statements of Governor Pritzker when he emphasized the need for transparency by gas utilities in the ratemaking process in his published statement of priorities: “It’s unfair and costly to consumers to allow gas companies to get away with not providing basic transparency and safety information to consumers and regulators.” The City notes that although PGL was willing to take Mr. Rábago’s oral directions on how to direct its ECOSS software, Mr. Rábago stated that his limited access “does not equate to the ability to actually manipulate the ECOSS model, as is possible in the many jurisdictions where open-source ECOSS models are used.” COC Ex. 4.0 at 4:66, fn. 7. The City highlights that, although the results of this limited access to the PGL ECOSS demonstrated quantitatively the dramatic inflation of PGL’s calculation of customer costs due to its decision to include large amounts of demand-related costs in that calculation, the City’s position remains that PGL’s non-transparent, judgment-loaded ECOSS cannot be accepted to determine fixed customer charges.

The City disagrees with PGL’s attacks on Mr. Rábago’s approach to properly calculating “customer costs.” The City counters that PGL ignores the pages of Mr. Rábago’s testimony showing that his approach is supported not only by the Commission’s policy objectives but by authorities as well-regarded as Mr. Bonbright, the NARUC Manual, and more recent rate design analysts. See, e.g., COC Ex. 2.0 at 33-35. Moreover, the City advances that Mr. Rábago himself is a highly regarded expert in the field, having served as a public utility commissioner, utility executive, U.S. Department of
Energy official, and law school professor on utility regulation. COC Ex. 2.0 at 1-3. The City also points out that the esteemed experts who participated at the request of the AG and the PIO also support Mr. Rábago’s analysis. See, e.g., ELPC IB at 17-18; AG Ex. 8.0 at 16-17; PIO Ex. 4.0 at 51-52. Thus, the City declares that PGL’s claim that Mr. Rábago’s approach is “unsupported” is itself unsupported and inaccurate.

The City also disagrees with PGL’s assertion that Mr. Rábago’s basic customer approach is “a significant departure from the historical methods approved by the Commission.” PGL IB at 176. The City counters that, putting aside that there is no requirement to comply with “historical methods” particularly in a rapidly transforming energy industry, PGL does not name a single “historical method” from which Mr. Rábago’s approach would be a departure. The City continues that, in any case, regardless of any “historical methods,” PGL does not show how its ECOSS complies with the Commission’s most recent 2015 directive that non-storage demand related distribution costs should not be recovered as fixed customer charges. 2015 Order at 176. The City asserts that Mr. Rábago supports, rather than departs from, the Commission’s 2015 directives because the purpose of his proposal to use the basic customer method is to strip “non-storage demand related distribution costs” from the costs used to derive fixed customer charges, as the Commission stated it seeks to do. Id.

The City also disputes PGL’s claim that Mr. Rábago’s approach to analyzing “customer costs” would “result in diminishing cost causation responsibility.” PGL IB at 176. The City disagrees and asserts that PGL’s claim again is unsupported and, at best, demonstrates PGL’s lack of understanding of Mr. Rábago’s approach. The City contends that using the basic customer method ensures that there is cost causation responsibility in the exact manner that the Commission desires. The City notes that, with respect to inter-class allocation, Mr. Rábago is not suggesting that any costs attributable to a particular service classification not be paid by the customers within that service classification. Moreover, the City advances that, if the basic customer method is applied to the ECOSS so that its calculation of “customer costs” includes only true customer costs and not demand-related costs, the customer charge to all those S.C.1-HTG customers would ensure that the mix of fixed and volumetric charges vastly improves, not diminishes, cost causation responsibility. The City concludes that, under Mr. Rábago’s approach to developing the ECOSS, costs are attributed to cost causers; and, as the Commission further directed, the basic customer method would “eliminate[e] inequitable cross-subsidization of high users by low users of natural gas.” 2015 Order at 176.

The City also disputes PGL’s claim that Mr. Rábago’s basic customer method “would shift costs from the residential class to other customer classes.” PGL IB at 176. The City declares that this PGL position is erroneous and unsupported.

The City also controverts PGL’s argument that the basic customer method should not be used because it is based on “marginal costs,” not embedded historical costs. PGL IB at 178. The City notes that PGL made this same argument through the rebuttal testimony of Mr. Nelson, but in its Initial Brief, the City did not refer to Mr. Rábago’s explanation in response. Mr. Rábago explained at length that “the classification of customer costs should be based on incremental or marginal costs to connect and establish service for a new customer, [his] recommended approach is entirely consistent with the Illinois requirement for an “embedded cost of service” study, required at 83 Ill.
Admin. Code 285.5110.33; and [he] did not and do[es] not recommend taking the marginal cost of service study approach in classifying customer costs.” He concluded that “Witness Nelson’s explanation of the differences between embedded and marginal cost of service studies … is, therefore, irrelevant and misleading.” COC Ex. 4.0 at 13-14; "Id. at fn. 33.

The City also disagrees with PGL’s assertion that the City’s “goal is simply to set the customer charge as low as possible. Anything in excess of the bare minimum would be classified as demand costs.” PGL IB at 178. Mr. Rábago answered this argument in his Rebuttal Testimony and the City avers that PGL failed to acknowledge his answer. COC Ex. 4.0 at 14.

The City states that perhaps the only valid point that PGL raises is its concern that PGL may not know how to determine true customer costs if it is required to do more than include all costs assigned to a particular FERC Chart of Accounts category: “Choosing one installation to represent all installations as the ‘most basic’ is subjective and will vary widely,” PGL says. PGL IB at 179. The City counters that, for a company that touts its “longstanding practice of carefully analyzing and assigning costs” (PGL IB at 179), PGL’s concern that it does not know how to determine basic system costs is surprising. In any case, the City advises that PGL need only start with the Basic Cost ECOSS that it prepared at the City’s request to build an ECOSS that is based on the basic customer method. See COC Ex. 4.0 at 7.

The City contends that PGL makes four assertions to attempt to support its ECOSS, but they all fail to do so. The City claims that PGL first asserts that its ECOSS should be accepted because “[c]ost causation is the fundamental principle underlying [its] ECOSSs.” PGL IB at 175. However, by definition, every ECOSS is based on cost causation principles, as the NARUC Manual excerpt states: “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.” AG Ex. 8.01 at 30. With respect to “costs” in this context, the NARUC Manual further states: “‘Cost’ like ‘value,’ is a word of many meanings, with the result that people who disagree, not just on minor details but on major principles of ratemaking policy, all may subscribe to some version of the principle of service at cost.” Id. at 27 (internal citations omitted). Thus, in the City’s view, PGL’s statement that its ECOSS is based on cost causation is merely tautological and provides no reason to support its ECOSS use as the sole basis for determining fixed charges versus volumetric charges in this case.

Second, the City points to PGL’s justification of its ECOSS that it is “consistent with allocation methods that the Commission has approved in the last several rate cases” (PGL IB at 177) and that the basic customer method for determining costs used to generate customer charges proposed by the City’s expert Mr. Rábago “would be a significant departure from the historical methods approved by the Commission”. Id. at 176, 178. However, the City notes that PGL does not identify which “last several rate cases” or “historical methods” it is referencing, other than North Shore Gas’ rate case filed in 2020, decided in 2021, in which the ECOSS and rate design were not contested issues.

The City further argues that in both its Initial Brief and its testimony, PGL never cites to or describes the Commission’s statements in the 2014 Rate Case regarding rate
design policy for fixed customer charges. The City, particularly through Mr. Rábago’s testimony examined that 2015 Order and its implications for PGL’s ECOSS and rate design at length, including in reply to the Commissioners’ Question No.1. See., e.g., City’s Reply to PGL’s Response to Commissioners’ Question No.1 at 2; COC Ex. 2.0 at 12-14; COC Ex. 4.0 at 8, 9, 14-15. The City highlights that PGL does not dispute that the Commission made these findings in the 2014 Rate Case; PGL just remains silent.

The City highlights that the Commission found that PGL’s “[straight fixed variable ("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 [1] attributing costs to cost causers, [2] encouraging energy efficiency and [3] eliminating inequitable cross-subsidization of high users by low users of natural gas.” Id. The City also emphasizes that to start the “shift away from SFV based rates,” and without examining the method by which PGL’s ECOSS distinguished between customer-related and demand-related costs, the Commission ordered Staff’s “more conservative” rate design proposal to use only ECOSS customer costs, not ECOSS demand-related costs, as the basis for determining the customer charge. Id.

In the City’s view, the point of the Commission’s 2015 decision was not which of PGL’s “fixed costs” should properly be classified as customer costs versus demand costs, but rather to prevent PGL from expressly including indisputable ECOSS-classified demand costs as part of the basis for the residential fixed customer charge. Id. The City insists that nothing in the Commission’s 2015 Order found that PGL can use its ECOSS to insert “demand related distribution costs” (Id.) into its classification of “customer costs” to inflate the amount of costs that it can recover as customer charges. The City emphasizes that nowhere in PGL’s Initial Brief or testimony does PGL address the language of the Commission’s decision regarding the Commission’s important rate design policy directives. Indeed, the City finds that even the term “energy efficiency,” important to the City’s, State’s, and the Commission’s policy, is missing from PGL’s discussion of its ECOSS in its Initial Brief. The City also notes that PGL’s failure to address the Commission’s statement of rate design policy was noted by the AG’s expert Mr. Larkin-Connolly, too. See, e.g., AG Ex. 8.0 at 11.

Third, the City highlights that PGL attempts to justify its ECOSS by asserting: “Service lines, house regulators, and metering assets are all necessary to connect a customer to Peoples Gas’ system, and their costs do not change with fluctuations in usage. Therefore, the cost of those assets are and should be directed towards customers that use them.” PGL IB at 178-179 (internal citations omitted). In the City’s view, PGL’s argument reveals that PGL is confusing who should pay for those costs with how those costs should be paid for. Commonwealth Edison Co., Docket Nos. 18-1725/18-1824 (cons.), Order on Rehearing regarding Rate RTOUPP at 27 (Apr. 1, 2020).

The City is not disputing that the class of customers who generate costs should pay for them, but it asserts that a critical additional issue in rate design is how they should pay for them, i.e., whether through fixed customer charges or volumetric charges, including so that there is intra-class inequity and energy conservation is encouraged. The City reasons that, once classification and allocation assign costs to the appropriate service classification, rate design should ensure proper intra-class assignment of cost
responsibility, which has not occurred with respect to PGL's ECOSS. See, e.g., COC Ex. 4.0 at 15. Moreover, the City argues that PGL’s attempt to support its ECOSS is not persuasive because PGL does not discuss what it has admitted in its testimony—that costs of service lines, house regulators, and metering assets do change with usage, in the sense that high users of gas have higher costs of connection, as in larger meters, regulators and service lines. The City points to the testimony of PGL witness Nelson for examples of PGL’s record evidence showing that these costs are inflated by demand-related costs. PGL Ex. 6.0 REV at 16; see also City CIB at 36-39; COC Ex. 2.0 at 16-19; 21-26.

The City argues that in order to address the inequity of charging low gas users for the high connection costs of high gas users, an inequity which the Commission wants to “eliminate” (2015 Order at 176), the City’s proposed basic customer method would ensure that the collection of PGL’s approved revenue requirement is, in fact, “directed towards customers that use them,” as PGL states it wants. PGL IB at 178-179. The City explains that under the City’s proposed basic customer method, much of PGL’s approved costs will be collected by a volumetric charge, rather than PGL’s proposed high fixed customer charge, thereby avoiding (1) the “lowest users bear[jing] the brunt of rate increases;” (2) “diminish[ed] . . . incentives to engage in conservation and energy efficiency;” and (3) “inequitable cross-subsidization of high users by low users of natural gas.” 2015 Order at 176. The City further asserts that the basic customer method cures PGL’s deviation from correct assignment of cost responsibility within its service classifications by ensuring that low-demand customers within each service classification are not forced to pay the demand-related costs incurred by high-demand customers in their service classification. The City also notes that, due to volume balancing adjustment rider (“Rider VBA”) and other protective riders, PGL’s ability to recover all of its costs attributed to each class of customers would be fully protected. COC Ex. 2.0 at 43.

PGL’s final argument in support of its ECOSS is that Staff supports its ECOSS. PGL IB at 176. The City asserts, however, that there is no indication that Staff ever evaluated the ECOSS to determine how well it accomplished the Commission’s rate design policy goals. The City expresses concern because, in its view, an ECOSS is more than a benign accounting exercise; especially when used to directly set customer charges. For these reasons, the City challenges Staff’s support for PGL’s ECOSS without justifying how it accomplishes the Commission’s rate design objectives, including supporting the energy policies issued by the City and the State.

The City further highlights that Staff and PGL attempt to justify PGL’s use of its ECOSS, even though based on the Proprietary Software, by noting that North Shore used the same Proprietary Software in its 2020 rate case, made the same types of classification decisions, and North Shore’s rate design was approved. COC Ex. 2.0 at 20, fn. 50; Staff Ex. 13.0 at 5. The City notes, however, that the Commission found in North Shore’s 2020 rate case that, “No parties opposed North Shore’s proposal for S.C. No. 1 HTG customers and it is therefore approved.” See N. Shore Gas Co., Docket No. 20-0810, Order at 90-91 (Sept. 8, 2021). According to the City, neither Staff nor PGL acknowledges that in the 2020 North Shore rate case, neither the ECOSS nor rate design was a contested issue and the fact that inaccessible software was used was not mentioned in the Commission’s Final Order. The City points out that, in this rate case, in contrast, the City, the AG, and
several other parties have examined the facts, the law, and the Commission’s policy and oppose PGL’s attempt to increase its fixed customer charges. See, e.g., AG Ex. 8.0 at 4-20; COFI/LAC Ex. 1.0 at 100-109; PIO Ex. 4.0 at 45-53. In any case, the City was not a party to the North Shore rate case and should not now be prevented from challenging the ECOSS’s lack of transparency and improper calculation of "customer costs.”

The City also reasons that Staff’s position may be signaling to the Commission that PGL’s ECOSS need not be the final basis for determination of fixed customer charges. The City asserts that due to its myriad flaws, the Commission should not use PGL’s ECOSS as a blueprint; instead the Commission should require PGL to conduct a new ECOSS in which demand-related costs are not included in customer costs, and further require PGL to set its customer charges fully consistent with rate design and public policies.

It is the City’s strong belief that the reason PGL did not instruct its ECOSS to classify customer costs to exclude demand-related costs is because, just as PGL did in its 2014 Rate Case, PGL seeks to recover all of its “fixed” costs, i.e., “sunk” costs, in a fixed customer charge. COC Ex. 2.07; NS-PGL Ex. 17.0 REV at 14; COC Ex. 2.0 at 12-13; COC Ex. 4.0 at 8. Thus, the City concludes that, because of the way PGL uses to its ECOSS to classify demand-related costs as "customer costs,” PGL’s SFV rate design approach continues to this day. See COC Ex. 4.0 at 8. The City recommends that just as the Commission did in its 2015 Order, the Commission should reject PGL’s approach to calculating the customer charge in this case.

The City asserts that PGL’s approach is inconsistent with the Commission’s 2015 Order, and in any case, is not what is required now. It is the City’s view that an ECOSS should be used so that costs are attributed to cost-causers, energy conservation and efficiency are encouraged, and intra-class inequity is minimized, just as the Commission established in its 2015 Order. Moreover, according to the City, since the 2014 Rate Case, there is new urgency regarding energy efficiency, and there are new State and City policies demanding energy equity, affordability, and a shift away from fossil fuel use. See, e.g., COC Ex. 2.0 at 6-11. The City concludes that because PGL’s ECOSS is (a) inconsistent with rate design and public policies; and (b) was not conducted in an open and transparent manner, PGL has not met its burden of proof that its ECOSS should be approved as the basis for determining ratepayers’ fixed customer charge. It is the City’s position that using PGL’s ECOSS as the basis for fixed customer charge rate designs would result in unjust and unreasonable rates.

c. PIOs’ Position

PIO witness Cebulko states that Peoples Gas’ classification of distribution costs such as mains and service lines as customer related can be controversial. This statement is true for classifying gas service lines as well. Because the Company’s calculations of customer-related unit costs are used to inform its customer charge, all else equal, the Company is incentivized to inflate customer-related costs for two reasons. First, a higher customer charge increases revenue stability for the Company. Second, the growing economic attractiveness of electrification presents an additional risk to gas utilities as customers may choose to electrify. As demonstrated below, all else equal, higher customer charges decrease the economic attractiveness of electrification. Thus, the
Company’s decision to classify service lines as 100% customer-related aligns with its economic interests – at the expense of ratepayers and state policy goals as described below. Mr. Cebelko states that reclassification services as non-customer related, and eliminating the uncollectible charge would decrease the overall customer charge. PIO Ex. 1.0 at 105-107.

d. Commission Analysis and Conclusion

The Commission agrees with the Companies that the distribution system must connect all customers and handle peak demands. The City, ELPC, and PIO want to move towards the basic customer method and claim this method will limit customer related charges to those that vary with the number of customers on the system. The City argues the fixed customer charge should be limited to the marginal cost to connect the customer to the system. PIO states that the classification of service lines costs is a way of increasing the customer charges.

The Commission required the Companies to limit cost recovery of fixed customer charges to the customer costs identified in the ECOSS. The Companies’ proposals result in cost-based rates that are consistent with the Commission’s principle of cost causation.

The Commission does not agree that the City’s and PIOs’ respective proposals to shift costs in the basic customer method are a meaningful way to determine cost causation, and they are therefore, rejected. The City’s concerns about the Proprietary Software that generated the Companies’ ECOSS, including requirements for future rate cases, are addressed in Section VIII.B.1.f. of this Order.

3. Class Revenue Allocation

a. Companies’ Position

Class revenue allocation is the third step in the process—after functionalization and classification. The Companies explain that in general, demand-related costs are allocated to classes based upon a demand allocation factor, commodity-related costs are allocated based upon a commodity allocation factor, and customer-related costs are allocated based upon a customer allocation factor.

BOMA—a trade association that represents owners of Chicago office buildings—would like to see revised revenue requirements that are more favorable to S.C. No. 2 customers. BOMA’s direct testimony failed to describe its preferred adjustments or apportionment methods or offer any analysis of the costs that contribute to PGL’s total revenue requirements. NS-PGL Ex. 16.0 at 21–22. It was only in rebuttal, after Mr. Nelson pointed this out, that BOMA witness Pruitt described various portions of PGL’s ECOSS that he recommended adjusting. BOMA refers to these as “discrepancies” in the ECOSS. See, e.g., BOMA IB at 4. Mr. Pruitt concluded that using actual historical cost data by customer class causes a cost shift to S.C. No. 2. NS-PGL Ex. 27.0 at 5–6. Mr. Pruitt also challenged the Tax Gross-Up Factor.

PGL addressed various “discrepancies” that BOMA raised, and also explained how it supported its allocation of costs to S.C. No. 2 and other customer classes. Id. at 6. PGL’s methodologies are the same ones that North Shore employed and the Commission approved in North Shore’s test year 2021 rate case. As Staff explained, the Companies’ methodologies are consistent with principles of cost causation and follow industry
guidelines. Staff IB at 108. BOMA’s proposed adjustments to PGL’s ECOSS should be rejected.

The City asserts that PGL’s revenue allocation should be disregarded because PGL’s ECOSS does not distinguish between demand and customer costs. COC IB at 46. For the reasons stated above, the Companies assert that PGL has properly classified these costs.

The Companies dispute the City’s assertion that A&G costs should be treated as non-customer costs that vary with changes in demand. COC Ex. 2.0 at 34. The Companies assert that A&G costs are incurred in the general administration of the business and cannot be readily assigned to utility functions or classifications. NS-PGL Ex. 16.0 at 16. Therefore, these costs are generally apportioned using a composite allocation of other direct costs. Id. at 15.

The Companies state that they allocated labor-related A&G expenses based upon the allocated results of the labor portion of O&M expenses. Plant-related A&G expenses were allocated based upon the allocated results of net plant in service. General O&M-related A&G expenses were allocated based upon the allocated results of all other total O&M expenses, excluding A&G expenses. NS Ex. 6.0 REV at 20; PGL Ex. 6.0 REV at 23. The Companies assert that this treatment of A&G costs is consistent with guidance provided by the American Gas Association Gas Rate Fundamentals text, the NARUC Gas Manual, and the NARUC Electric Utility Cost Allocation Manual. NS-PGL Ex. 16.0 at 16–17.

b. City’s Position

The City does not disagree with PGL’s process for allocating costs to customer classes, per se. See PGL Ex. 6.0 REV at 8. Nor does the City disagree with PGL’s statement that demand, commodity, and customer costs should be allocated to classes based on their relevant allocation factor. Id. However, although the allocation of revenue requirement to classes is typically arithmetical once an allocator is settled upon, the City asserts that the determination of appropriately classified costs, particularly in the demand and customer classifications, requires careful consideration, which, as the City explains, PGL has not done. The City repeats its position that PGL has not instructed its ECOSS to distinguish between true demand costs (which vary by the quantity of gas demanded and size of the plant and equipment needed to supply that amount of gas) and true customer costs (which are the smallest, basic costs of connecting customers to the system). See id. Therefore, it is the City’s view that, although PGL has applied the formula correctly to allocate customer costs to specific classes of customers, the customer costs that it is allocating to those specific classes were not correctly selected. As a result, the City opposes the resulting class revenue allocation amount derived from that flawed ECOSS. Therefore, the City recommends that the Commission reject both the flawed ECOSS and the revenue allocation amounts resulting from that flawed ECOSS.

c. BOMA/Chicago

In his direct testimony, BOMA/Chicago witness Pruitt analyzed PGL’s ECOSS, noting that it inappropriately and unreasonably shifts costs to members of PGL S.C. 2,
the service classification pursuant to which most of BOMA/Chicago’s members receive natural gas service. BOMA Ex. 2.0 at 3-5. Mr. Pruitt concluded that the ECOSS over-allocates costs to S.C. 2, and that S.C. 2 uses generally less of the overall distribution system and services provided by PGL than S.C. 2’s cost allocation suggests. *Id.* at 4-6. BOMA/Chicago notes that, in his rebuttal testimony, PGL witness Nelson dismissed Mr. Pruitt’s analysis without addressing Mr. Pruitt’s assessment of the usage characteristics of S.C. 2. Mr. Pruitt’s rebuttal testimony responded by identifying specific instances in which PGL’s ECOSS departed from the allocation factors it provided, with no explanation. BOMA/Chicago also notes that PGL’s surrebuttal testimony again failed to meaningfully respond to or contest the discrepancies Mr. Pruitt identified (or, for many of them, did not respond at all), and Mr. Pruitt’s recommended adjustments should therefore be adopted by the Commission.

In his direct testimony, Mr. Pruitt explained that the ECOSS is designed to use metrics to determine the responsibility of each class of PGL customers for the costs of PGL’s natural gas delivery system. The revenue allocations established in the ECOSS serve as the basis for PGL’s proposed rates. BOMA Ex. 2.0 at 4.

Under the metrics utilized by the ECOSS, Mr. Pruitt noted, BOMA/Chicago members are responsible for a relatively smaller and decreasing percentage of the cost of service as compared to the ECOSS from the previous rate case, Docket Nos. 14-0224 and 14-0225 (cons.) (the “Prior ECOSS”). BOMA Ex. 2.0 at 4-5; BOMA Ex. 2.2. Mr. Pruitt observed that, as compared to the Prior ECOSS, several material changes in S.C. 2’s usage of the PGL system (relative to other customer classes) suggest that S.C. 2 customers should be assigned a decreased cost allocation. *See BOMA Ex. 2.0 at 5.*

BOMA/Chicago states that these factors indicate that the S.C. 2 class is using comparatively less of the overall distribution system and services provided by PGL. *Id.* at 6. Accordingly, Mr. Pruitt testified that the ECOSS should reflect a moderate decrease in cost allocation to the S.C. 2 customer class. *Id.* Instead, PGL’s ECOSS reduces the cost allocation to S.C. 2 customers by less than 0.71% compared to the Prior ECOSS. *Id.* As a result of the increase in PGL’s revenue requirement and rate of return, actual rates charged to S.C. 2 customers, particularly the Distribution Charge, will rise disproportionately and without justification. *Id.* at 9-10. Mr. Pruitt therefore recommended that the ECOSS be adjusted to better reflect the changes in system usage by S.C. 2 customers. *Id.* at 8-9.

BOMA/Chicago explains that, in his rebuttal testimony, PGL witness Nelson dismissed BOMA/Chicago’s concerns regarding the ECOSS as “rationalizations” without meaningfully responding to BOMA/Chicago’s testimony. NS-PGL Ex. 16.0 at 21. Notably, BOMA/Chicago finds that Mr. Nelson did not contest Mr. Pruitt’s testimony regarding the changes in usage characteristics of S.C. 2 since the Prior ECOSS. Instead, Mr. Nelson suggests that the increased revenue requirement allocated to S.C. 2 customers is driven by the $3.1 billion increase in PGL’s rate base since its last rate case. *Id.* at 22. BOMA/Chicago highlights that Mr. Nelson described one change in PGL’s cost classification since the Prior ECOSS (relating to load dispatching costs that were shifted from customer to demand costs) as a possible explanation for the increased allocations to S.C. 2 that Mr. Pruitt identified, but offered no explanation for why the changes in “overall consumption, number of customers, coincident peak demand, average daily
deliveries, and system load factor” since the prior PGL rate case are not reflected in the ECOSS. See BOMA Ex. 2.5 at 2; NS-PGL 16.0 at 22.

In Mr. Pruitt’s rebuttal testimony, BOMA/Chicago identified several discrepancies in PGL’s ECOSS that result in the unreasonable shifting of costs from other customers classes to S.C. 2 customers. BOMA Ex. 2.5 at 3. Specifically, Mr. Pruitt explained that PGL’s ECOSS (i) inappropriately allocates the cost of general line-item expenditures to specific rate class expenditures (BOMA Ex. 2.5 at 4-6); (ii) arbitrarily allocates rate base costs in instances where general cost allocations were split between Customer and Demand Categories (ld. at 6-8), and (iii) inconsistently and incorrectly applies the Tax Gross-Up factor. Id. at 8.

Mr. Pruitt noted that the Revenue Requirements presented in the PGL ECOSS are the product of a rate base cost allocation methodology that categorizes rate base costs according to whether the cost is attributable to the number of consumers served by the system (“Customers”) and/or by the peak demand for the PGL system (“Demand”). See Sch. E-6, ‘Allocators-I-L5’, at 18-22; Sch. E-6, ‘Allocators-E-L5’, at 18-22. The ECOSS sets forth the extent to which rate base costs are attributable to the Customer category, Demand category, or both categories. BOMA Ex. 2.5 at 3.

Once a cost is attributed to the Average Customers category, the Demand category, or both, Mr. Pruitt explained, PGL applies an “External Allocation Factor” to allocate those rate base costs to the various rate classifications. Id. at 3. Fifteen external allocation factors are defined in Section 285.5110, Embedded Gas Cost of Service Study, WPE-6.14. Id. According to PGL, External Allocation Factor values are based either on specific historical cost data provided by PGL for each rate classification (i.e., meter costs for each rate classification), or a general allocation based on the percentage of Customers or Demand represented by each rate classification. See WPE-6.14-List of external allocators and their descriptions. Mr. Pruitt reviewed these External Allocation Factors, and their application to the various categories of rate base costs to produce the “Balances by Rate Class” that are provided on Schedule E-6, “Report-L6” at 27-33. Id. at 4. He explained that his goal was to determine whether the rate base and revenue requirements presented on Schedule E-6, “Report-L6” were adequately explained and supported in Schedule E-6. In doing so, he determined which of the rate base figures were calculated using a historical-cost External Allocation Factor, and which were calculated using a general External Allocation Factor. Id. Additionally, Mr. Pruitt assessed whether each of the rate base revenue requirements presented on Schedule E-6, Report-L6 was correctly calculated. Id.

Mr. Pruitt identified multiple seemingly general line-item base rate costs in the ECOSS (e.g. “PS_Distribution Services,” “CWIP_Distribution Services,” or “PD_Distribution Services”) that were nevertheless allocated according to specific rate class percentages. BOMA Ex. 2.5 at 4. BOMA/Chicago notes that these items appeared general in nature, did not reference any specific equipment or service that is identifiable to any rate classification, and are not referenced in any of the definitions of External Allocation Factors provided by PGL’s as provided in WPE-6.14. BOMA Ex. 2.5 at 4. Therefore, Mr. Pruitt testified that PGL’s use of a specific historical cost allocator, rather than a general allocation, for these line items was unexplained and unjustified. Id.
BOMA/Chicago contends that the lack of justification for PGL’s departure from this general External Allocation Factor here is emphasized by the fact that PGL did offer fulsome explanations for similar departures on other lines. For example, Mr. Pruitt noted that for Line 18 on Schedule E-6, ‘Report L-6’, PGL’s WPE-14, Item 9 provides a definition of Industrial Measuring and Regulating Devices that helps to explain how it allocated costs to Line 18. BOMA Ex. 2.5 at 5. However, PGL provided no similar explanation, for how it determined the allocation for Line 13. *Id.* Furthermore, BOMA/Chicago explains, the title of Line 13 ("PS_Distribution Services") provided no guidance as to how that category was calculated, lists no specific equipment, and is not defined in PGL’s definitions of External Allocation Factors Schedule E-6, ‘Allocators-E-L6’. *Id.* In this and the other instances Mr. Pruitt identified, the allocations proposed by PGL should be rejected and the general External Allocation Factor should be applied instead. *Id.*

BOMA/Chicago explains that in BOMA Exhibit 2.6, Mr. Pruitt re-calculated the allocations for each of the Lines for which PGL failed to explain its deviation from general External Allocation Factors – Lines 13, 29, and 42. *Id.* at 6. Replacing the specific rate base allocation for these expenses with the more general allocation based on Customers, BOMA/Chicago notes, would not alter the total level of qualified rate base for PGL, but more accurately allocates these costs amongst the customer classes using the External Allocation Factors that PGL provides. *Id.* Mr. Pruitt noted that only two of the adjustments he proposed on BOMA Exhibit 2.6 result in reductions to the allocations to S.C. 2. *Id.* However, his proposed adjustments would reduce the total rate base allocated to S.C. 2 by $67,922,525. *Id.*

The second discrepancy Mr. Pruitt noted was related to rate base cost allocations in instances where the cost was of a general nature, but the cost allocation was split between the Customer and Demand categories. BOMA Ex. 2.5 at 6. In these cases, he noted that the appropriate rate base cost allocation to a rate class should equal the sum of the products of: (a) the general Customer cost allocator and the percentage allocated by PGL to that line item (see Schedule E-6, ‘Report-L5’ at 13-16); and (b) the general Demand cost allocator (i.e., Customer, Demand) and the percentage allocated by PGL to that line item (id.). BOMA Ex. 2.5 at 6.

BOMA/Chicago notes that BOMA Exhibit 2.7 described nine additional line items where Mr. Pruitt identified similar discrepancies. *Id.* at 7. Correcting the calculations for these line items would not alter the total level of qualified revenue requirements for PGL, but more accurately allocates these costs based on the data provided within the ECOSS. *Id.* As with the first categories of discrepancies noted, not all of the adjustments Mr. Pruitt proposed on BOMA Exhibit 2.7 result in reductions to the allocations to S.C. 2. However, Mr. Pruitt’s proposed adjustments would reduce the total rate base allocated to S.C. 2 by $17,843,379. *Id.* at 8.

BOMA/Chicago notes that, in his surrebuttal testimony, PGL witness Nelson provided a brief explanation of one of the nine discrepancies raised by Mr. Pruitt (net retirement benefits), but neglected entirely to address the remaining eight. NS-PGL Ex. 27.0 at 6. While Mr. Nelson disagreed that these nine items are discrepancies, Mr. Nelson argued vaguely that “the allocation of these costs were explained and supported in detail in my direct testimony, work papers, and my rebuttal testimony.” *Id.* However,
BOMA/Chicago states that Mr. Nelson did not engage critically with Mr. Pruitt's calculations or provide any meaningful response to Mr. Pruitt's rebuttal testimony.

In his direct testimony, Mr. Pruitt also noted concerns with the PGL tax gross up factor. Mr. Pruitt explained that the Tax Gross Up Factor adjusts the revenue requirement upward to ensure that PGL can meet its approved return on and return of rate base after income taxes.  BOMA Ex. 2.0 at 7.  PGL performed this calculation by dividing its calculated Income Insufficiency (Ex. 6.2, line 43) by a Tax Gross Up Factor of 40.5% (Ex. 6.2, line 44) to yield an Additional Taxes on Income Deficiency (Ex. 6.2, Line 45) which is then included in the Revenue Requirement from Base Sales value (Ex. 6.2, Line 55).  BOMA Ex. 2.0 at 6-7.  BOMA/Chicago notes that while the value of the Tax Gross Up Factor for the Total Jurisdiction (the entire PGL utility) was set at 45.01%, a higher average Tax Gross Up Factor of 46.67% was applied to the S.C. 2 customer classes.  Id. at 7.  For reference, the average Tax Gross Up Factors for other rate classes were lower than the 45.01% average for the Total Jurisdiction, with the S.C. 1 customer class receiving an upcharge of only 44.34% and the S.C. 4 customer class receiving an upcharge of only 41.99%.  Id.  The increased cost represented by increasing the Tax Gross Up Factor to the S.C. 2 customer class is approximately $1.5 million per year for the customer class.  Id.  Mr. Pruitt noted that an explanation for this variance is not provided in PGL’s exhibits or its direct testimony.  Id.

BOMA/Chicago states that, in his rebuttal testimony, Mr. Nelson responded briefly that PGL “allocated all income taxes based on the composite allocation of total rate base,” and that PGL has used the same methodology since at least 2009.  NS-PGL Ex. 16.0 at 23-24.

In his rebuttal testimony, Mr. Pruitt reviewed the accuracy of the application of the Tax Gross-Up Factor by dividing the values presented by PGL for Additional Taxes on Income Deficiency by the Income Deficiency.  BOMA Ex. 2.5 at 8.  This review revealed that the Tax Gross-Up Factor is not a consistent 45.01% for all rate classifications as indicated in the filing.  Id.  Instead, Mr. Pruitt observed the following effective Tax Gross-Up Factors for the various rate classifications: S.C.1 (44.34%), S.C.2 (46.67%), S.C.3 (42.60%) and S.C.4 (41.93%).  Id.  BOMA/Chicago observes that these are material deviations from the proposed 45.01% value proposed by PGL.  Id.  The effect of the inconsistent application of the Tax Gross-Up Factor has the net effect of increasing the revenue requirement for S.C.2 customers by $1,548,436.  All other rate classifications realize a net reduction in revenue requirement.  Id.  Details of these calculations were presented in BOMA Exhibit 2.8.

BOMA/Chicago states that the net result of these inconsistencies Mr. Pruitt identified is that PGL assigns significant rate base allocations to the S.C. 2 customer class without proper justification.  BOMA Ex. 2.5 at 8-9.  BOMA/Chicago contends that this unexplained cost shifting results in real prejudice to its members.  In effect, PGL asks the Commission to simply take the company at its word that the ECOSS adequately justifies PGL’s cost allocations.  BOMA/Chicago argues that the Commission should reject this suggestion, particularly in light of the fact that PGL’s ECOSS software is a “black box,” which none of the parties – including Staff – had access to during this proceeding.  COC Ex. 4.0 at 21-22; see Tr. at 106–108. (Aug. 10, 2023).  Mr. Pruitt’s analysis demonstrated
that the ECOSS does not adequately justify its cost allocations, and PGL refused to respond directly to that analysis.

BOMA/Chicago therefore requests that the Commission adopt the ECOSS adjustments presented in BOMA Ex. 2.9. This exhibit presents a proposed revenue requirement schedule that consistently applies the value of the metrics presented in Schedule E-6 for consideration and adoption by the Commission. BOMA Ex. 2.5 at 9. As Mr. Pruitt noted, these changes will not reduce the revenue requirement for PGL. However, BOMA/Chicago states that adopting these changes will allow for a more transparent and simplified allocation of costs to all rate classifications, and prevent cost shifting between rate classifications to ensure that costs are borne by the most applicable consumers. Id.

d.  Commission Analysis and Conclusion

The Commission agrees with Staff and the Companies that the ECOSS follows cost causation principles and are consistent with the methods approved by the Commission in the past. The Commission notes that the demand-related costs are allocated to classes based upon a demand allocation factor, commodity-related costs are allocated based upon a commodity allocation factor, and customer-related costs are allocated based upon a customer allocation factor. The Commission agrees with the Companies and Staff that this is consistent with the same methodologies that were approved in the North Shore 2021 rate case. The Companies’ ECOSs determined the costs of each class revenue allocation. The Companies’ methods follow the industry guidelines and the Class Revenue Classifications are approved.

IX.  RATE DESIGN

A.  Uncontested Issues

1.  Schedule of Rates for Gas Charges

North Shore proposes changes to its Schedule of Rates for Gas Service, ILL C.C. No. 17. NS Ex. 7.0 REV at 5. NS Ex. 7.1 contains copies of the tariff sheets that North Shore filed in this proceeding. These changes are uncontested and therefore are approved.

Peoples Gas proposes changes to its Schedule of Rates for Gas Service, ILL C.C. No. 28. PGL Ex. 7.0 REV at 5. PGL Ex. 7.1 contains copies of the tariff sheets that PGL filed in this proceeding. These changes are uncontested and therefore are approved.

2.  Uncontested Tariff Revisions

a.  Rider SCC, Storage Service Charge

For North Shore, under the revenue requirement proposed in this proceeding, the Rider SCC Storage Banking Charge, which applies to transportation customers, is 0.055 cents per therm of storage capacity and the Storage Service Charge, which applies to sales customers, is 0.863 cents per therm of consumption. NS Ex. 7.0 REV at 14. North Shore’s proposed revisions to Rider SCC to reflect the proposed Storage Banking Charge and Storage Service Charge arising from the revenue requirement proposed in this proceeding are approved.
For Peoples Gas, under the revenue requirement proposed in this proceeding, the Rider SSC Storage Banking Charge, which applies to transportation customers, is 1.094 cents per therm of storage capacity and the Storage Service Charge, which applies to sales customers, is 8.042 cents per therm of consumption. Peoples Gas’ proposed revisions to Rider SCC to reflect the proposed Storage Banking Charge and Storage Service Charge arising from the revenue requirement proposed in this proceeding are approved.

b. Other Housekeeping Changes

Peoples Gas proposes changing the “Customer Charge” line item on the bill to “Fixed Charge” to reflect the fact that more than the service classification customer charge is billed in this line item. PGL Ex. 7.0 REV at 20. Staff witness Harden supports this change (Staff Ex. 5.0 at 25) and no party presented evidence contesting it. This change is therefore approved.

3. Rider QIP

Peoples Gas agrees with Staff witness Alan’s proposal that the Commission’s Final Order in this proceeding include a Findings and Ordering paragraph specifying that the Rider QIP costs for 2016 through 2023 remain subject to review for reasonableness and prudence in the applicable annual QIP reconciliation dockets. See Staff Ex. 2.0 at 19; see also NS-PGL Ex. 12.0 REV at 3. The Commission approves Staff’s proposed language and includes such a Findings and Ordering paragraph herein.

The Company also agrees with Mr. Alan’s proposed adjustments to Peoples Gas’ Rider QIP tariff (see Staff Ex. 2.0 at Attach. E), which address the proposed treatment of QIP work completed in 2023 in light of the authorizing statute’s sunset as of December 31, 2023, and further agrees to file the tariff revisions as suggested by Mr. Alan. Because the prudence and reasonableness of QIP expenditures through 2023 will be addressed in separate reconciliation proceedings, the Commission finds that it would be inappropriate for those issues to be considered in this case, and all parties that have addressed or referenced this issue agree that this rate case is not the proper docket to address the historical reasonableness and prudence of QIP work. NS-PGL Ex. 12.0 REV at 4; see also AG Ex. 1.0 at 12; AG Ex. 3.0 at 35; PIO Ex. 1.0 at 25.

4. Existing Riders

a. Rider SST

The AG proposes removing the Daily Demand Measurement Device Charge from Rider SST in response to its move to an AMI network. NS Ex. 7.0 REV, 17-48; PGL Ex. 7.0 REV, 18. No party contests this change, and it is therefore approved.

B. Contested Issues

1. Residential Rate Design

a. Companies’ Position

For S.C. No. 1 NH customers, North Shore proposes recovering 100% of customer costs as allocated through the EC OSS through the customer charge. NS Ex. 7.0 REV at 9. This will result in a recovery of approximately 88% of non-storage related fixed costs
through the customer charge, with all remaining costs being recovered through a
distribution charge. *Id.* at 10. North Shore proposes increasing the customer charge from
$0.50981 to $0.56084 per day for S.C. No. 1 NH sales and transportation customers. *Id.*
at 10. Storage-related costs will be recovered under Rider SSC. North Shore proposes
increasing the distribution charge to 10.759 cents per therm. *Id.* at 10.

For S.C. No. 1 HTG customers, North Shore proposes maintaining 100% recovery
of customer costs through the customer charge. *Id.* This proposal will recover only 59%
of non-storage related fixed costs through the customer charge, with all remaining non-
storage related costs being recovered through a distribution charge. *Id.* at 10-11. North
Shore proposes increasing the charge from $0.79309 to $0.88653 per day for S.C. No. 1
HTG sales and transportation customers. *Id.* at 10. Storage-related costs will be
recovered under Rider SSC. North Shore proposes increasing the distribution charge to
16.281 cents per therm. *Id.* at 11.

North Shore’s proposed revenue requirement and rate design will result in new
distribution rates and related distribution revenues, or Rate Case Revenues (“RCR”) for
Rider VBA, that would be in effect until new rates become effective in a subsequent
proceeding.

For S.C. No. 1 NH customers, Peoples Gas, proposes recovering 100% of
customer costs as allocated through the EC OSS through the customer charge. PGL Ex.
7.0 REV at 10. This will result in a recovery of approximately 92% of non-storage related
fixed costs through the customer charge, with all remaining costs being recovered through
a distribution charge. *Id.* at 10–11. Peoples Gas proposes increasing the customer
charge from $0.53819 to $0.77091 per day for S.C. No. 1 NH sales and transportation
customers. *Id.* at 11. Storage-related costs will be recovered under Rider SSC. Peoples
Gas proposes increasing the distribution charge to 21.774 cents per therm. *Id.*

For S.C. No. 1 HTG customers, Peoples Gas proposes maintaining 100% recovery
of customer costs through the customer charge. *Id.* at 11. This proposal will recover only
62% of non-storage related fixed costs through the customer charge, with all remaining non-
storage related costs being recovered through a distribution charge. *Id.* Peoples Gas
proposes increasing the charge from $1.01392 to $1.47162 per day for S.C. No. 1 HTG
sales and transportation customers. *Id.* Storage-related costs will be recovered under
Rider SSC. Peoples Gas proposes increasing the distribution charge to 31.948 cents per
therm. *Id.*

Peoples Gas’ proposed revenue requirement and rate design will result in new
distribution rates and related distribution revenues, or RCR for Rider VBA, that would be
in effect until new rates become effective in a subsequent proceeding.

The Companies note that the principal rate design issue in this case is the fixed
charge. Various intervenors assert that the Companies’ proposed increases in the S.C.
No. 1 customer charges should be rejected because they disagree with the amount of the
fixed charge. They assert that the fixed charge is too high; the Companies should be
indifferent to rate design because they are guaranteed revenue recovery; and high fixed
charges penalize low-income customers, contravene energy efficiency goals, and send
the wrong price signals. *E.g.*, AG IB at 67–74; COC IB at 50–52; ELPC IB at 5, 8–14;
AARP IB at 3–6. Some of intervenors’ recommendations include the following:
• AG witness Larkin-Connolly contends generally that the Companies should reduce their fixed charges and move towards volumetric recovery of costs. AG Ex. 4.0 at 18-19. For North Shore’s residential heating customers, he recommends that costs be split 50/50 between fixed and volumetric charges and for North Shore’s residential non-heating customers, he recommends a 70/30 fixed-to-volumetric split. Id. at 19-20.

• The City’s witness Rábago argues that the Companies’ ECOSS should use a “base customer” method to determine the fixed charge. COC Ex. 2.0 at 4.

• PIO witness Cebulko recommends, presumably for Peoples Gas, reducing its customer charge to $24.86/month ($.81739/day), claiming that increasing fixed charges contradicts state policy goals encouraging efficiency and electrification. PIO Ex. 1.0 at 102.

The Companies contend that all of the intervenors’ proposed changes should be rejected, as they are not connected to well-established ratemaking principles and do not provide a reason to reject the Companies’ rate designs as unreasonable or unjust.

First, intervenors’ approach to this issue appears to advance a narrow goal according to the Companies: to reduce the fixed charge, thereby allowing customers using less natural gas to reduce their bills even more by avoiding responsibility for the fixed costs of serving them. The more intervenors seek to shift revenue responsibility away from certain customers and towards others, the farther their proposals move away from long-standing established cost-causation principles and the closer they come to cross-subsidization. While the Companies understand intervenors’ motivation, the Companies have a responsibility to approach rate design from a more neutral perspective, just like the Commission. 220 ILCS 5/9-241. The Companies cannot be indifferent to their rate designs. They assert that good and proper rate design is rooted in principles, including rate recovery, cost causation, price signals, equity, and gradualism—all of which are incorporated into the Companies’ approaches.

Second, the Companies’ fixed charges do not penalize any customers. Nor do they send inaccurate price signals. The Companies explain that they incur many costs irrespective of customer demand. Allocating these costs based on usage would therefore make little sense; it would simply result in shifting costs to a subset of customers, which if anything is more akin to a penalty than a design rooted in cost-causation. The intervenors may dislike the fixed charge, but that does not mean it sends the wrong price signal.

Third, the Companies state that the intervenors’ claims that PGL’s customer charge is too high ring hollow. ELPC measured PGL’s proposed charge against PGL’s charge in 2007 simply to try to portray the increase as extreme. This arbitrary comparison fails to consider any changes in the economic landscape or PGL’s expenses in the last sixteen years. ELPC simply labels PGL’s request “extreme” and says it would move PGL’s customer charge “into uncharted territory.” ELPC IB at 5. Other intervenors characterize the charge as unaffordable. However, the Companies contend that the fundamental issue is whether PGL’s rate is just and reasonable, not whether it seems
high in light of what a particular rate was sixteen years ago. 220 ILCS 5/9-101; BPI 1, 146 Ill.2d at 208. The intervenors also fail to adequately consider that it has been nine years since PGL has sought a rate increase, that PGL only seeks to recover customer costs through its customer charge, and that PGL’s design is not results-oriented but rather allocates costs according to well-established principles.

Fourth, the Companies add that the fact that several intervenors challenge the Companies’ fixed charges does not make their positions any more reasonable. For one, they generally represent the same group of customers on this issue. Shared interests aside, the AG, PIO, and COC propose significant changes to the Companies’ rate designs that depart from established ratemaking principles. For example, as Staff pointed out in its initial brief, the AG’s 50/50 and 70/30 fixed-to-volumetric charge proposals for North Shore’s residential heating and residential non-heating customers, respectively, are arbitrary. Staff IB at 117–118. PIOs’ proposal to cut PGL’s customer charge nearly in half is extreme, unsupported, and would subject customers to significant volatility as more charges would have to be recovered through volumetric rates. COC’s recommendation is to freeze and then continuously lower PGL’s customer charge over “a short period of time, no longer than five years” based on the “basic customer method.” COC IB at 55. As the Companies have explained, Mr. Rábago’s “basic customer method” is not a sound approach to rate design.

Finally, the Companies note that the intervenors assert that high fixed charges are inconsistent with energy efficiency and conservation goals. COC even goes so far as to say that the focus of this case “should be on price signals to ratepayers about energy conservation and efficiency, affordability, and decarbonization—and about how higher use today drives higher fixed costs tomorrow.” Id. at 51. NS and PGL argue such sweeping statements miss the mark. As stated above, the Commission’s review of the Companies’ proposed rate designs must consider whether they result in just and reasonable rates that reflect cost-causation principles. Energy efficiency goals may be one consideration, but it is just one of many, and intervenors have not provided any evidence that the Companies’ proposals fail the just and reasonable test. Moreover, there are many ways to address energy efficiency goals. Significantly increasing volumetric charges, reducing fixed cost recovery, and requiring some customers to subsidize others is not an appropriate way to do so. The Companies assert that their proposals are rooted in sound principles and should be approved.

b. Staff’s Position

The Companies proposed recovering only the customer-related costs through its fixed customer charge as identified in the ECOSS. Staff Ex. 5.0 at 11. Staff observes that before 2015, the Companies were moving toward recovery of all fixed costs through the fixed customer charge. Id.

Staff agrees with the Companies’ rate design proposal to recover only customer-related costs through fixed customer charges. Id. at 12. Staff witness Harden emphasized that the Commission has previously encouraged attributing costs to cost causers, which supports energy efficiency and can eliminate cross-subsidization. Id. The Commission has also referenced the General Assembly’s explicit directive to encourage energy efficiency. Section 8-104 of the Act 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. 220 ILCS 5/8-104. The Commission has recognized that reducing the fixed charges of customers can reduce overall natural gas usage, as envisioned by the General Assembly in creating the Section 8-104 energy efficiency programs. Id.

Staff witness Harden testified that the rate design proposals present customers with a better opportunity to control their bills due to more costs recovered in the distribution charge rather than in the fixed customer charge. Id. at 12-13. Specifically, fixed customer charges do not vary with usage whereas variable distribution charges are based on the amount of gas used by a customer. To the extent the proposed fixed customer charge is below Peoples Gas’ allocated fixed costs to serve the customer, the remaining fixed costs are recovered through distribution charges. The Company’s proposal allocates only 89.2% of Peoples Gas’ allocated fixed costs to serve residential non-heating customers to the customer charge, which provides a better opportunity for customers to control their bills than if customer charges were based on 100% of Peoples Gas’ allocated fixed costs to serve this customer class. COC Cross Ex. 7.

If the Commission approves a different revenue requirement than that proposed by the Companies, NS and PGL state they will make the necessary adjustments to the appropriate ECOSS accounts and allocation factors based on the findings in the Commission’s Final Order in this proceeding. Staff has no objection to the Companies’ proposal to submit ECOSSs that are based on the Commission’s Final Order as compliance filings. Staff Ex. 5.0 at 13.

c. AG’s Position

The AG argues that the Companies’ rate designs are unfair to low-usage customers, are not cost-based, and result in unaffordable fixed fees that customers must pay before they use a single therm of gas. According to the AG, the Companies’ proposal to collect approximately 60% of their residential heating revenue requirements and an even greater percentage of their residential non-heating revenue requirements through monthly fixed charges is contrary to the state’s clean energy, equity, and affordability goals. The AG thus asks the Commission to reject NS’s and PGL’s rate design proposal. The AG argues that North Shore and Peoples Gas, along with Nicor, collect most of their residential revenues through fixed charges while Ameren collects a greater percentage of residential revenues through a volumetric charge. See AG IB at 68, citing AG Ex. 4.00 at 13: Table 3. The AG argues that the Companies’ reliance on high fixed monthly charges is inconsistent with the State’s clean energy, equity, and affordability goals because it reduces the incentive for customers to limit their natural gas consumption, provides customers with less control over their bills, would require customers to pay as much as $44.76 before they use a single therm of gas, and results in lower-use customers paying more per unit than higher-use customers. NS approximate monthly fixed charges: $26.97 (heating customers); $17.06 (non-heating customers). PGL approximate monthly fixed charges: $44.76 (heating customers); $23.45 (non-heating customers). The approximations for both companies were calculated by multiplying their proposed daily fixed charges by 365 and dividing the result by 12. AG Ex. 4.00 at 12: Table 2.
It is undisputed that P.A. 102-0662 places a significant emphasis on clean energy and rate affordability. AG Ex. 2.00 at 24; see also 220 ILCS 5/16-108.18(a)(6)–(8). To achieve these goals, AG witness Larkin-Connolly testified that ratepayers need to use energy more efficiently and use less fossil fuel (i.e. natural gas). AG Ex. 4.00 at 14. By collecting more revenue through the fixed customer charge, Mr. Larkin-Connolly testified that the Companies lower their volumetric prices and reduce the incentive for customers to limit their natural gas consumption. Id. at 14–15. Conversely, Mr. Larkin-Connolly stated that if the Companies were to collect a greater percentage of their revenue through volumetric charges, then it would incentivize customers to reduce their gas consumption to lower their overall bills. Id.

According to Mr. Larkin-Connolly, the Companies’ reliance on high fixed customer charges also overburdens low-usage customers who are more likely to be low-income customers because it gives them less control over their bills. Id. at 15; see also LAC Ex. 1.0 at 6. Mr. Larkin-Connolly testified that low-usage customers pay significantly more per therm with a higher fixed charge than they pay with a lower fixed charge. AG Ex. 4.00 at 16: Figure 1. The AG notes that, as shown on PGL Sch. E-8 Rev., 16% or 1.35 million of PGL’s residential heating customer bills are for less than 10 therms, and 86%, or 1 million, of PGL’s residential non-heating customer bills are for less than 10 therms. PGL Sch. E-8 Rev. at 1–2. Likewise, the AG notes that 6.6% or 118,298 of North Shore’s residential heating customer bills are for less than 10 therms, and 69% or 13,352 of North Shore’s residential non-heating customer bills are for less than ten therms. NS Sch. E-8, at 1-2. Mr. Larkin-Connolly showed that the cost per therm is dramatically higher for the first 10 therms of natural gas, and that this effective, high per therm cost affects a substantial number of PGL and NS bills and customers. Sch. E-8R at 1; see also AG IB at 69, citing AG Ex. 4.00 at 16: Figure 1.

The AG also contends that the Companies’ proposals are inconsistent with the principles set forth by Governor Pritzker in a Chicago Sun-Times Op-Ed. AG Ex. 4.00 at 18. In this Op-Ed, the AG notes that Governor Pritzker expressed concerns about how the possible migration of customers from natural gas services to electric cooking and heating will affect those customers who cannot afford to make this transition. The AG states that he provided several proposals to protect gas customers—particularly low-income Black and Brown people and rural residents—from unreasonably and unsustainable high rates. Id. According to the AG, the most relevant to this discussion is Governor Pritzker’s proposal that natural gas companies recover most of their revenues through “volumetric rates, not customer charges – so those who use more gas pay more.” Id. The AG asserts that the Companies’ rate designs are inconsistent with this approach because NS and PGL rely on high fixed charges, which burden low-usage customers and allows those who use more gas to pay a lower effective per-therm cost.

The AG notes that the Commission has demonstrated a preference for lowering exorbitant fixed charges in recent rate cases, especially for companies like NS and PGL that have a revenue decoupling mechanism like Rider VBA. In their 2014 rate cases, the Commission found “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.” Docket Nos. 14-0224/14-0225 (cons.), Order at 176. Similarly, the AG notes that in a ComEd rate design
proceeding, the Commission recognized the need to balance fixed and volumetric rates to accommodate the state’s interest in promoting energy efficiency, adopting “the parameters put forth by the AG which decrease the fixed customer charge and increase the variable charges for customers in the SFNH and SFH classes. This policy to reduce high fixed charges supports Illinois’s energy efficiency goals without affecting the average customer’s bill.” Commonwealth Edison Co., Docket No. 13-0387, Order at 75 (Dec. 18, 2013), see also Illinois Commerce Commission Report Concerning Coordination Between Gas and Electric Utility Energy Efficiency Programs and Spending Limits For Gas Utility Energy Efficiency Programs, (“EE Report”) at 23 (Aug. 30, 2013).

In response, the Companies generally argue that the AG’s and other intervenors’ proposals “would allow smaller customers to subvert paying their share of costs that the Companies incur irrespective of customer demand.” NS/PGL IB at 188. This mischaracterizes the intervenors’ positions and ignores the regressive nature of the Companies’ proposed rate structures. The AG reasserts that the Companies’ high fixed charges require low-usage customers (who are more likely to be low-income customers) to pay a higher effective per unit cost than higher usage customers. AG Ex. 4.00 at 15; see also COFI/LAC Ex. 1.0 at 6. In other words, the AG contends that lowering the fixed charges is necessary because up to this point low-use customers have been overpaying through the fixed charges and would continue to do so under the Companies’ proposed rate designs.

The AG highlights that the Commission has expressed support for reducing customer charges and increasing volumetric rates in order to create the appropriate incentive to the Companies’ customers to use energy efficiently. In Peoples Gas’ and North Shore’s last joint rate case, Docket Nos. 14-0224/14-0225 (cons.), the Commission acknowledged both the reduced efficiency incentive resulting from high fixed charges and how fixed charges negatively affect the cost of service for low usage customers. Docket Nos. 14-0224/14-0225 (cons.), Order at 175–176. Similarly, in Ameren’s 2018 gas rate case, the AG notes that the Commission approved a reduction in customer charge cost recovery from 70% to 60%. Ameren Ill. Company d/b/a Ameren Ill., Docket No. 18-0463, Order at 13 (Nov. 1, 2018).

The AG states that the Companies’ continued use of high fixed fees would also “adversely impact a majority of seniors, who use less than the average amount of natural gas” and would “reduce the control that older customers have over their monthly bills, by weakening the incentives for energy conservation and energy efficiency measures.” AARP IB at 1–2. The Companies’ high fixed charges would subvert the General Assembly’s goal of providing much needed relief to struggling ratepayers because “[a]greeing to the Companies’ requests would represent a regressive burden on ratepayers not justified by the record, and worse, would make it even harder to structure an effective [low-income discount rate] that provides meaningful relief to low-income customers.” COFI/LAC IB at 5.

To be consistent with recent Commission decisions and the state’s energy policies, the AG requests the Commission require North Shore to collect no more than 50% of its residential heating revenue requirement and no more than 70% of its residential non-heating revenue requirement through its fixed charges. AG Ex. 4.00 at 19–20. According to the AG, this would result in a fixed charge of approximately $22.78 (or $0.74884 per
day) for residential heating customers and $6.07 (or $0.19949 per day) for residential non-heating customers per month. *Id.* The AG believes this reflects a more gradual approach for non-heating customers, although the Commission should move the non-heating fixed charge closer to the 50% threshold in future rate case proceedings. *Id.*

Mr. Larkin-Connolly did not make specific recommendations for PGL’s residential rate design in his direct testimony, but made a general recommendation “that any rate design that is adopted for Peoples Gas’ residential heating and non-heating customers result in a reduction in the proportion of base revenues collected through the fixed charge.” *Id.* at 21. In rebuttal, Mr. Larkin-Connolly reviewed the alternative PGL rate designs proposed by PIO witness Cebulko and the City’s witness Rábago. Mr. Cebulko proposed that the Commission require PGL to adopt a fixed residential heating charge of $24.86 per month, down from the current charge of $30.84. PIO Ex. 1.0 at 6. Mr. Rábago proposed that the Commission require PGL to adopt a residential fixed charge that is either 50% of the Commission approved customer costs ($22.46 for heating customers, $11.77 for non-heating customers) or continue PGL’s current rate design ($30.84 for heating customers, $16.70 for non-heating customers). COC Ex. 2.0 at 39. Mr. Larkin-Connolly testified that these proposals were improvements to PGL’s proposed rate design, but in the interest of gradualism, proposed that the Commission adopt Mr. Rábago’s second option and require PGL to keep the same residential fixed charges that it has under current rates. AG Ex. 8.00 at 16–17.

The AG also asks the Commission to direct NS and PGL to collect a greater percentage of revenue through volumetric charges in future rate cases; this should include consideration of increasing block rates, which would increase the volumetric rate as usage increases, and further align the Companies’ rate designs with state policy. As noted in NARUC Staff Subcommittee on Gas’ Gas Distribution Rate Design Manual (“NARUC Rate Design Manual”), these types of rates have two core objectives “promoting conservation by discouraging customers from using large quantities of gas” and “provid[ing] an affordable level of gas services to meet basic human needs, often referred to as lifeline rates.” AG Ex. 8.01 at 22. By moving toward increasing block rates, the AG believes the Commission can ensure that NS and PGL’s rate designs are consistent with the state’s clean energy, energy efficiency, and affordability policies.

The Companies, however, claim their proposals are cost-based and “limit cost recovery through the Customer Charge to customer costs as identified in the ECOSS.” PGL/NS IB at 188. The AG acknowledges that cost causation is the touchstone of any ECOSS. But they also point out that rate design consists of more than merely allocating costs by category—it can achieve desired policies and outcomes, and directly affects the prices customers pay. While Staff supported the Companies proposals and referred to the intervenors’ alternatives as “arbitrary,” Staff acknowledged that “utility ratemaking and rate design is more art than science with ample judgment that can reflect the final result.” Staff IB at 109. Based on the NARUC Rate Design Manual, which states that “[u]tility rate design is more art than science. Even with a seemingly objective standard, such as cost of service-based rates, there remains considerable latitude for judgment and personal value systems to affect the final result.” AG Ex. 8.01 at 27. The AG asserts that the intervenors’ proposals are not arbitrary because adopting lower customer charges is necessary to ensure the Companies implement cost-based rate designs that are
consistent with the state’s clean energy, equity, and affordability goals and do not overburden lower-use customers. Further, both the PIO and the COC witnesses found Peoples Gas’ ECOSS categorization of customer costs overinclusive. PIO IB at 53 (Noting “the Commission should consider . . . whether Peoples Gas is subjectively misclassifying certain costs as ‘customer-related’ when they are more appropriately classified as demand-related costs.”), COC IB at 36–37 (Noting that PGL uses a “subjective and broad view of customer costs that is unlimited in scope and provides no distinction between demand versus customer costs, as those classifications are typically made.”). Since NS and PGL use the same ECOSS models, the AG argues that it is reasonable to assume that these same errors are present in North Shore’s rate design. Staff IB at 108. The AG asks the Commission to reject the Companies’ proposed rate designs because they contain overinclusive definitions of customer costs and are not cost-based.

The AG reminds the Commission that the Act does not require the Companies to collect customer costs through a fixed charge, but does require that utility service ensure efficiency, environmental quality, reliability, and equity. 220 ILCS 5/1-102. For purposes of utility regulation, the AG notes that equity means “the fair treatment of consumers and investors,” requires “the cost of supplying public utility services is allocated those who cause the costs to be incurred,” and that “rates for utility services are affordable and therefore preserve the availability of such services to all citizens.” Id. at 1-102(d). In its Initial Brief, ELPC pointed out that “[a]s recently as 2007, Peoples’ customer charge was $9.00 per month. Today, residential heating customers pay a fixed charge of $30.84 per month, an increase of more than 300%” and if the Commission approves PGL’s proposed $44.76 customer charge in this proceeding “it would mean that the customer charge has increased nearly 500% since 2007.” ELPC IB at 5. The courts have made clear that “[t]he Commission cannot fulfill its statutory duty to balance the competing interests of stockholders and ratepayers without taking into account the interest of ratepayers by considering the impact of proposed rates on ratepayers.” Citizens Util. Bd. v. Ill. Comm’n, 276 Ill. App. 3d 730, 737 (1st Dist. 1995). According to the AG, the record shows that NS’s and PGL’s proposed rate designs are unfair to low-usage customers, are not cost-based, and result in unaffordable fixed fees that customers must pay before they use a single therm of gas.

For these reasons, the AG recommends that the Commission require North Shore to collect no more than 50% of its residential heating customer revenue through a fixed charge and no more than 70% of its residential non-heating customer revenue through a fixed charge. The AG also recommends that the Commission adopt the recommendation of City witness Rábago and require PGL to maintain the fixed charges that it has under current rates. The AG believes these combined recommendations will result in a more equitable rate structure that is consistent with Illinois’ clean energy, equity, and affordability goals.

d. City’s Position

PGL’s proposed residential rate design includes having a fixed customer charge and a volumetric, per-therm charge for non-storage distribution costs. PGL currently imposes customer charges for each subclass in the S.C.1 Small Residential Service class. For S.C.1-NH customers, the current customer charge is $16.37 per customer per
month (rounded to $0.54 per day). COC Ex. 2.06. PGL proposes to increase the customer charge for S.C.1-NH customers by 43% to $23.45 (rounded to $0.77 per day). For S.C.1-HTG customers, the current charge is $30.84 (rounded to $1.01 per day). \textit{Id.} PGL proposes to increase the current customer charge for S.C.1-HTG customers by 45% to $44.76 per month (rounded to $1.47 per day). The City asserts that Chicago gas utility customers would be required to pay their assigned customer charge of $23.45 (S.C.1-NH) or $44.76 (S.C.1-HTG) before using a single therm of gas. The City’s position is that PGL’s proposed rate design based on these unjust and unreasonable customer charges should be rejected by the Commission because the rate design is contrary to Commission direction, law, and policy.

The City asserts that PGL’s residential customer charge cannot be approved because it is based on a flawed ECOSS and improper classification of costs as “customer costs.” In sum, the City’s position is that PGL’s ECOSS is the result of PGL using a proprietary software program that it has improperly directed to classify many accounting categories of costs as “customer costs,” even though those categories of costs include demand-related costs. See, e.g., PGL Ex. 6.0 REV at 14-17; COC 2.07. By not limiting the customer charge to costs that meet the definition of customer costs, i.e., costs that vary with the number of customers, PGL: (a) violates the principle that rates should be based as much as practicable on cost causation; and (b) is not abiding by the direction of the Commission’s 2015 Order to design rates that attribute costs to cost causers, encourage energy efficiency, and eliminate inequitable cross-subsidization of high-users by low-users of gas. Docket No. 14-0224/0225 (cons.), Order at 176 (“2015 Order at 176”).

Although PGL asserts that it has classified residential costs correctly, the City’s view is that, in fact, PGL’s residential design undermines the Commission’s 2015 Order in which PGL was required to design its residential rates so that cost causers pay for their costs, customers are encouraged to conserve and use energy efficiently, and unfair allocation within a service sub-classification is avoided. 2015 Order at 176. The City’s conclusion is that PGL made decisions in its proprietary ECOSS software that lumps into the classification of “customer costs” a broad range of costs that, in fact, are demand-driven, and which inflates fixed customer charges contrary to the Commission’s policy objectives.

It is the City’s view that PGL’s flawed ECOSS and inflated customer costs have significant improper rate design consequences for residential customers that the Commission has sought to prohibit. The first negative consequence is that small users with low connection costs are required to subsidize the customer connection costs of higher-demand customers. It follows, according to the City, that when fixed customer charges impose unreasonably higher costs on users that do not cause those costs, those charges unjustly discriminate, resulting in rates that are inconsistent with Commission-recognized rate design policies and not just or reasonable.

The City points to language in the Commission’s 2015 Order finding that fixed customer charges are “patently” regressive, meaning that they have greater cost impact on low-users that are often also low-wealth customers. 2015 Order at 176. As shown by Mr. Rábago in his Table KRR 2 (City CIB at 62), the calculations in which, were not contested by PGL, the regressive effect of high fixed customer charges can be illustrated
through an effective rate per-therm of gas for S.C.1-HTG customers. See COC Ex. 2.0 at 26-27; PGL Ex. 7.7. In Table KRR-2 (City IB at 62), per PGL, the average rate per-therm, for a S.C.1-HTG customer using 20 therms per month is $2.64, which is about three times higher than the effective rate for such a customer who uses 86 therms per month (PGL’s predicted average amount for all S.C.1-HTG customers), at $0.92 per-therm.

Mr. Rábago further analyzed that these impacts become economically regressive when there is a high correlation between low usage rates and lower household incomes. Mr. Rábago cited to the U.S. Department of Health and Human Services, which administers the federal LIHEAP, and which analyzed 2009 Residential Energy Consumption survey data from the U.S. Department of Energy, and applied 2017 data on weather and fuel price to estimate that low-income households use about 10% less gas in their homes than non-low-income households. COC Ex. 2.0 at 29-30. Mr. Rábago further showed that PGL, unreasonably in his view, assumes that low-income customers have the same average usage as other customers in their respective classes. COC Ex. 2.0 at 30. Mr. Rábago’s analysis is disturbing, according to the City, because the regressive nature of high fixed customer charges matter in Chicago and Illinois because they affect affordability, efficiency, and equitable energy sector transformation. Id. The City asserts that PGL did not address or dispute Mr. Rábago’s findings, relying instead on its position that it only did what the Commission allowed it to do—collect in customer charges all costs its ECOSS labeled as “customer costs.” The harmful effects of PGL’s customer charge rates are important to the City, however.

Not only is the issue of energy affordability important to the City, but the City highlights that utility rate affordability is important to the Illinois General Assembly and the Commission, which comprehensively studied low-income issues and found that low-income discount rates for income-qualified customers are appropriate and necessary. See Illinois Commerce Commission Low-Income Discount Rate Study Report to the Illinois General Assembly (Dec. 15, 2022). It is the City’s view that many Chicago households live with very high energy burdens and in a state of energy insecurity. For these customers, a very high percentage of household income is devoted to getting essential energy services. The City believes that because of such high energy burdens, these residents are at risk of losing access to service or having to forego other essential goods and services if they experience even modest interruptions in household income.

Mr. Rábago analyzed the impact of the regressive customer charge on low-wealth ratepayers. COC Ex. 2.0 at 31-32. He relied on the American Council for an Energy-Efficient Economy (“ACEEE”), which found that the median energy burden in Chicago is 2.7%, and the median energy burden among low-wealth customers is much higher at 8%. COC Ex. 2.0 at 31. About 25% of low-income households have energy burdens above 15%—more than 5.5 times higher than the median energy burden. Id. Approximately 20% of Chicago households have a high energy burden, defined as above 6%. Id. at 32. Also according to ACEEE, 10% have a severe energy burden—above 10% energy burden. Id. As Mr. Rábago explained: “These higher burdens create a constant risk of energy insecurity for low-wealth customers and are a function of high rates and low income in combination with legacy housing and energy-consuming home equipment that is older and less-efficient.” Id.
Further, the City is concerned that energy burden, like financial burden, is not experienced equally among Chicago’s low-wealth citizens. Based on Mr. Rábago’s research and analysis, 37% of Black households and 19% of Hispanic households face high energy burdens. *Id.* The City demonstrated that low-income, low-income multifamily, and black households experienced the highest median energy burdens in Chicago. *Id.* In the City’s view, PGL did not dispute Mr. Rábago’s testimony on this issue.

It is the City’s position that unaffordable customer charges cannot be allowed to continue to be imposed on any residential PGL customers. *Util. Servs. of Ill., Inc.*, Docket No. 21-0198, Order at 15 (Dec. 1, 2021) (“rates that are unaffordable cannot sensibly be considered reasonable”). Among their other many faults, high fixed customer charges are a significant factor in making gas bills unaffordable to many and, therefore, the City urges that the customer charges must be redesigned to end their inequities.

The City also opposes PGL’s residential customer charges because they conflict with State and City policy regarding least-cost and equitable utility services, which are prioritized in the Act. 220 ILCS 5/1-102. The City argues that the Illinois Legislature strongly favors energy efficiency, clean energy, decarbonization, beneficial electrification, and a fair and reasonable transition away from the use of fossil fuels. COC Ex. 2.0 at 8. The City showed that its law and policies call for the same on the local level. *Id.* at 9-10. The City is concerned that PGL’s proposed high customer charges are never reduced by how energy efficient a customer’s use is or whether the customer converts to an electric appliance—as long as they retain gas service. Therefore, the City concludes that uncontrollable customer charges negatively impact the affordability of energy efficiency investment paybacks and reduce the marginal cost of additional use. For the same reason, the City is concerned that high customer charges make it less economical and more difficult to pursue decarbonization. Mr. Rábago also asserts that high customer charges reduce the benefits that low-income bill assistance and weatherization assistance programs can provide individually and in total, which is a further concern of the City. COC Ex. 2.0 at 32. In sum, the City’s position is that high fixed customer charges send price signals that are anti-efficiency and anti-conservation, a rate design contrary to Illinois and City law and policy, and, therefore, cannot be accepted in this rate case.

It is the City’s view that Staff’s recommendation that PGL’s proposed rate design be approved, including its proposed high customer charges, is not supported by the evidence and should not be accepted. *See also* COC Ex. 4.0 at 21-23. The City believes that Staff accepts PGL’s residential rate design because it is based on PGL’s ECOSS’s calculation of “customer costs,” but Staff never examines the underlying logic that PGL has built into its calculation of customer costs. *Id.* at 21. The City also notes that Staff, like the City and other parties, are not privy to PGL’s proprietary ECOSS software program. COC Cross Ex. 4. The City illustrates this point using COC Table 2 (City CIB at 43), to show the dramatic impact of PGL’s ECOSS instructions to include demand-related costs in its “customer costs.” According to the City and based on the Basic Customer Method ECOSS, almost half of PGL’s “customer costs” for service lines have been inflated by demand-related costs. *Id.*

The City concludes that because Staff accepts, without further analysis, PGL’s statement that its fixed customer charge is based on “customer costs,” Staff allows PGL to subvert the language and intent of the Commission’s 2015 Order, and Staff’s support
for PGL’s proposed fixed customer charges for residential customers is not supported by the evidence in the record and, therefore, should not be credited.

The City concludes that PGL has not met its burden of production and proof to support its proposed fixed customer charges for residential customers. The City asserts that PGL should be required to re-run its ECOSS, using the basic customer method to design rates that are just and reasonable. The City asks the Commission to order PGL to follow a basic customer method in calculating its “customer costs” and, thereby, fixed customer charges and report, in an open and transparent way, to the Commission and all parties the results of such calculation within 180 days of the entry of the Final Order in this proceeding.

The City believes that PGL’s ECOSS can be instructed to follow appropriate cost-causation principles, because a rough version of that appropriate ECOSS was prepared when PGL re-ran its ECOSS based on Mr. Rábago’s verbal instructions. A summary of the results of that revised ECOSS is provided by the City at COC Table 2, page 43 of the City’s Corrected Initial Brief. The City urges that PGL should be required to develop instructions to its proprietary ECOSS software that allows the program to disaggregate customer-related costs from demand-related costs, and thereby develop a change in rate design based on that disaggregation. The City asserts that PGL’s continued reliance on its proprietary, inaccessible software does not cure the access or transparency problems associated with PGL’s unilateral decision to adopt a proprietary ECOSS tool, but the ECOSS prepared at Mr. Rábago’s request at least shows that more reasonable rates can be supported in this proceeding by an improved ECOSS formulation.

The City further proposes that, if the shift to a basic customer method would cause rate changes that are too abrupt—not gradual—PGL’s improper classification of demand-related costs as “customer costs” should not be continued. Instead, the City suggests that rates based on lower customer charges should be phased in, consistent with the principle of gradualism. Specifically, following the gradualism principle, starting in 2024, PGL should charge residential customers no more than the current dollar amounts that PGL charges as its customer charges for its two subclasses of residential customers. The City proposes that the Commission should then direct PGL to establish a schedule by which the S.C.1 fixed customer charges will be reduced to the level identified under new, accurately classified “customer costs” by instituting incremental annual reductions starting one year from the entry of the Final Order in this case. In the interest of rate change gradualism and rate predictability, the total number of years for the reductions to reach the new basic customer method customer charges should not be greater than five, and the percent reduction should be the same in each year. See COC Table 3, City CIB at 56. As appropriate, a similar approach can be implemented for other service classifications.

The City notes that, assuming PGL’s initially proposed revenue requirement for Test Year 2024, when PGL retains and does not raise the current customer charges for residential heating customers, the volumetric charge increases from $0.19477 per-therm (current per-therm distribution charge) to $0.48136 per-therm. COC Ex. 2.0 at 42-43. Although this is a significant increase in the volumetric rate, the overall bill for the average customer would remain the same as that proposed by PGL. However, the City recommends its proposal because the burden of such a per-therm rate increase would,
in the City’s strong view, be more equitably assigned to cost-causers—those who use more gas. The City asserts that its proposal would restore and strengthen the incentive to efficiently use gas, and there would be improved payback calculations for efficiency and decarbonization investments. The City notes that, under its proposal, PGL would be kept whole because of the operation of the VBA and uncollectibles riders, and PGL would see a meaningful price signal to improve its cost management. Id. Finally, the City recommends its proposal because PGL’s rate design should be required to conform to the Commission’s direction on rate design policy to develop just and reasonable rates.

The City believes that, as currently proposed, PGL’s customer charges will frustrate the Commission’s direction regarding cost-causation, energy efficiency, and other policies.

The City argues that, in this case, the focus should be on price signals to ratepayers about energy conservation and efficiency, affordability, and decarbonization—and about how higher use today drives higher fixed costs tomorrow, which are not the signals sent by PGL’s proposed rate design. The City contrasts that, in PGL’s proposed rate design, low-use customers are forced to pay for the higher costs to connect and serve customers with higher demands for gas. According to the City, PGL’s proposed rate design, the price signals in rates to low-users are distorted in favor of excessive consumption and the incentive to conserve is weakened by high fixed customer charges. The direction to PGL to keep connection costs low is also weakened. See COC Ex. 2.0 at 26-29.

The City further takes the position that the high percentage of customer charges in the average PGL bill sends a loud signal that ratepayers receive little price benefit from energy conservation or efficient use of energy. The City asserts that such charges signal that the costs of gradual electrification will be higher because there is little the customer can do to control their gas bill, and the marginal savings associated with gas use reduction are artificially suppressed. The City explains that, unless the customer cuts ties with the gas utility entirely, the payback on any electrification investments will be longer if the customer still must pay a high customer charge just for being a Peoples Gas customer. The City concludes that, under the unreasonably high fixed customer charges that PGL proposes, a customer achieves less of a benefit from choosing to electrify their appliances or heating systems or participating in energy efficiency programs, despite State and City policies encouraging such behavior.

The City’s position is that, in sum, PGL’s rate design sends many wrong price signals to customers and creates perverse incentives for the utility. COC Ex. 2.0 at 14, 24, 28-29. The City urges the Commission to reject PGL’s rate designs because they result in unjust and unreasonable rates.

e. COFI-LAC’s Position

As part of its rate filing, Peoples Gas proposed an increase of its customer charge from the current $30.84 to $44.76 per residential heating customer—an increase of more than 45%. COC Ex. 2.0 at 15. Peoples Gas also proposes to calculate this customer charge on a daily, rather than monthly, basis. COFI/LAC note that this change to a daily cost would be new for Peoples Gas, though North Shore has had daily fixed charges in place since 2020. AG Ex. 4.00 at 12. COFI/LAC refer to the monthly cost here in order
to avoid obfuscating the true cost of Peoples Gas’ regressive proposal. North Shore proposes an increase from approximately $24.12 to $26.97 per residential heating customer—a 12% increase. AG Ex. 4.00 at 12. While the percentage of costs Peoples Gas and North Shore will recover would differ somewhat based on each service classification, under these proposed rates Peoples Gas would recover about 62% of its costs via the customer charge, while North Shore would recover 59%, for residential heating customers. AG Ex. 4.00 at 13.

COFI/LAC argue that the Commission should reject these requests and adopt the AG’s proposal to lower the North Shore residential heating customer charge by, among other things, evenly splitting fixed and volumetric revenue collection. AG Ex. 4.00 at 18-19. The Commission should likewise adopt a proposal that would allow Peoples Gas to collect no more than 50% of its revenue requirement through the fixed customer charge, as proposed by the City of Chicago. COFI/LAC Ex. 1.0 (CORR) at 108; COC Ex. 2.0 at 39-45; AG Ex. 4.00 at 18-19. Agreeing to the Companies’ requests would represent a regressive burden on ratepayers not justified by the record, and worse, would make it even harder to structure an effective LIDR that provides meaningful relief to low-income customers, COFI-LAC point out. See COFI/LAC Ex. 1.0 (CORR) at 102-09.

COFI/LAC point out that the affordability of a utility’s rates is integral to making them just and reasonable. The General Assembly included in the Act the requirement that “the rates for utility services are affordable and therefore preserve the availability of such services to all citizens.” 220 ILCS 5/1-102(d)(viii). Moreover, the Illinois Appellate Court has held that when setting rates, the Commission must consider the impact of those rates on customers. Citizens Util. Bd. v. Ill. Commerce Comm’n, 276 Ill.App.3d 730, 738, 658 N.E.2d 1235 (1st Dist. 1995). The Commission cannot meet its duty to “protect[ ] the interests of the ratepayers …, without taking into account the varying effect of rate restructuring on consumers.” Citizens Util. Bd., 276 Ill.App.3d at 738.

COFI/LAC argue that achieving rates that are just and reasonable involves a balancing of investor and consumer interests. Citizens Util. Bd. v. Ill. Commerce Comm’n, 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995). The U.S. Supreme Court’s analysis in Bluefield has been adopted by Illinois courts in assessing the justness and reasonableness of rates. See, e.g, Ill. Bell Tel. Co. v. Ill. Commerce Comm’n, 414 Ill. 275, 287, 111 N.E.2d 329 (1953). In Bluefield, the U.S. Supreme Court held that a utility’s rates should reflect the opportunity—not a guarantee—to earn a return when a state commission sets rates, but that utilities have no constitutional right to profits. Bluefield, 262 U.S. at 693. 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 Pub. Util. Comm’n ex rel. City of Springfield v. Springfield Gas & Elec. Co., 291 Ill. 209, 216, 125 N.E. 891 (1919).

In fact, in setting rates, COFI/LAC assert, ratepayers’ interests should generally 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 Util., Inc. v. Ill. Commerce Comm’n, 51 Ill.App.3d 5, 10, 365 N.E.2d 312 (1977).
COFI/LAC point out that while rate design is supposed to be a revenue neutral exercise, for both investor profits and customer bills, customer charges have an outsized impact on affordability if not designed to appropriately reflect cost causation and customer usage characteristics that drive revenue collection. COFI/LAC state the Companies’ decoupling riders, which allows them to reconcile any failure to collect its authorized revenue requirement through a per therm surcharge to residential customers, negates the need to keep the Companies’ customer charge high in order to ensure the level of revenues needed to cover its costs and earn a reasonable rate of return.

A close look at the Companies’ proposed increases in their customer charges demonstrates they are financially unsound and overly burdensome for their customers, especially low-income customers who will experience an increase in the regressive customer charge most acutely, according to COFI-LAC. The customer charge is “regressive” in the traditional sense, i.e., the size of the charge is the same for all customers, yet its impact is felt more by lower-income customers. For the more than 300,000 low-income customers the Companies serve, Peoples Gas’ proposed customer charge increase would represent a nearly $47.2 million increase in costs annually, plus another $1 million for North Shore’s. COFI/LAC Ex. 1.0 (CORR) at 20, 104. This compares to $35 million in LIHEAP benefits Peoples Gas’ low-income customers received during the first four months of 2023, and $1.86 million in LIHEAP benefits for North Shore customers. In other words, Peoples Gas’ proposed customer charge increase would wipe out the entire value of LIHEAP benefits provided to customers during the first third of 2023, and more. North Shore’s customer charge increase would take up more than half of the LIHEAP benefits distributed during the first third of 2023. See COFI/LAC Ex. 1.0 (CORR) at 104 citing NS-PGL Responses to COFI 3.14. This is especially concerning given (i) ongoing, growing limits on the state’s ability to provide LIHEAP funding to all who need it, (Id. at 23-24; COFI/LAC Ex. 2.0 at 11), (ii) stagnating, and arguably falling, incomes within the Companies’ service areas, (Id. at 9-11), and (iii) the Companies’ increasing revenues per customer, COFI-LAC note. Id. at 12-13.

As the Commission noted in its report when decoupling riders were first approved, a significant customer charge increase is also unnecessary. The Companies’ VBA riders decouples revenue collection from customer usage. The purpose of these riders is to “stabilize[s] the recovery of variable distribution revenues through distribution charges due to variances in volumes of gas service used by customers.” COFI/LAC Ex. 1.0 (CORR) at 108-109. COFI-LAC remind the Commission that, as a result, the Companies will automatically recover revenue shortfalls—their risk of non-recovery is essentially zero. Increasing the customer charge will only increase low-income customers’ burdens even when they use less gas, at no ultimate benefit to the Companies.

Finally, the Commission’s goal of increasing household energy efficiency investments supports a lower customer charge for at least three reasons, COFI-LAC argue. First, increasing the customer charge would not provide a meaningful incentive for customers to reduce energy usage. In practice, research has shown that energy bill unaffordability tends to cause many customers to take “dramatic[] and unhealthy or dangerous[] steps” to make ends meet: closing off part of the home; keeping the home at unsafe temperatures; using kitchen appliances to supplement heating; and more. COFI/LAC Ex. 1.0 (CORR) at 102-103. Increasing the customer charge makes these
potentially harmful deprivation actions less impactful while increasing the likelihood that customers will be forced to turn to them. PIO witness Cebulko concurred, testifying that high customer charges penalize low-income customers because they “often consume less [gas] than higher income residents.” ELPC IB at 13, citing PIO Ex. 1.0 at 110-111.

Second, increasing the customer charge would disincentivize low-income homeowners from adopting energy efficiency measures. Low-income customers are already overly burdened by the Companies’ bills. COFI/LAC Ex. 1.0 (CORR) at 12-19. Adding this mandatory cost to their bills will only lower what disposable income these families have, making it even harder to invest in weatherization or other energy efficiency measures. COFI/LAC Ex. 1.0 (CORR) at 105-107.

Last, increasing the customer charge risks dampening the effect of price signals. A higher customer charge divorces customers’ perception of the costs of their gas usage from reality. AG Ex. 4.00 at 14-16; see also Ill. Commerce Comm’n, Report to the Ill. Gen. 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). Further, a lower customer charge “fits with the policy goals endorsed by Governor Pritzker” and “the state’s [P.A. 102-0662] goals” by “enabling consumers to realize a greater financial benefit from using gas more efficiently.” AG Ex. 4.00 at 21. As the City explained, too, small users with low connection costs are required to subsidize the customer connection costs of higher-demand customers under the Companies’ flawed rate design proposal, resulting in rates that are neither just, reasonable or nondiscriminatory. See COC IB at 60.

COFI/LAC also point out that the Commission has recognized the impropriety of such high customer charges and rejected them in past proceedings. For example, in Peoples Gas’ 2015 rate case, the Commission rejected a proposed monthly customer charge increase from $26.91 to $38.50 as “inconsistent with public policy.” 2015 Ill. PUC LEXIS 50, at *447, 529. There, a witness for the AG estimated that the AG’s ECOSS justified “collecting a maximum of 63% of the total cost of service through the customer charge.” Id. at 451. Also, in that same proceeding, the Commission mentioned that it had looked askance at Ameren’s request for an increase in its residential customer charge from 44.8% to 50% around the same time. Id. at 440.

COFI/LAC note that the Companies argue that failing to adopt their proposed customer charge would shift more of the “fixed costs of service” to customers using more natural gas, and “would allow smaller customers to subvert paying their share of costs that the Companies incur irrespective of customer demand.” NS-PGL IB at 189. Staff endorses this cost of service and rate design presentation, and offers no rebuttal to the Companies’ customer charge proposals, apparently accepting the Company’s proposed ECOSS and belief that any proposal that does not recover 100% of costs through the customer charge allows customers to potentially reduce their usage, small as that opportunity may be. Staff IB at 113-114.

However, as City witness Rabago points out, this position and alleged justification for high customer charges is based on a flawed ECOSS that broadly lumps demand-related infrastructure costs into a “fixed costs” category. For example, the City notes the Companies attribute Service Lines (Plant Account 380) (also called “services”) as (fixed)
“customer costs.” COC IB at 37, citing PGL Ex. 6.0 REV at 16. This cost of service classification, as presented in its ECOSS, belies its own recognition that its cost of connecting a customer to the gas system varies with the amount of gas the customer will use and that larger demand drives larger, more expensive services, including pipe, regulators, and other infrastructure. Id. at 37. The City further points out that PGL witness Nelson admits that costs of service lines vary with demand: “A service line is a lateral installed off distribution or high pressure main in order to serve a customer request for gas. In general, the more gas demanded by a customer or group of customers, the larger and more costly the service lateral will be.” Id. citing PGL Ex. 6.0 REV at 16.

The City notes, too, that “PGL does not know or attempt to understand how the cost to serve varies with residence type and/or differences in the level of demand.” COC IB at 38, citing COC Ex. 2.10; COC Ex. 2.11. This may be related to the fact that Peoples Gas has not provided a true, detailed ECOSS, instead providing a “summary report of a proprietary, private software run, with inputs that no one other than PGL has seen”—a “black box” ECOSS summary at a high level, at best, COFI-LAC argue. COC IB at 44. COFI-LAC urge the Commission to reject PGL’s proposal to continue ballooning fixed charges, which will disproportionately burden low-income and low-usage customers, based on meager evidence that these charges are remotely cost-based.

COFI-LAC asserts that focusing on and increasing revenue recovery through the customer charge should be rejected by the Commission for several reasons. First, increasing the customer charge, in which a substantial portion of the bill cannot be avoided through reduced usage, reduces the incentive for customers to reduce energy usage and is a particularly regressive rate design for low-income customers, who tend to have lower average usage compared to other customers.

PGL claims that its rates will still send accurate price signals about the costs of gas overall based on an unsupported claim in Ms. Egelhoff’s testimony that it will improve customers’ appreciation of the “costs of delivery service[.]” NS-PGL IB at 188, citing NS-PGL Ex. 17.0 REV at 14. This completely misunderstands what price signals are and how they work in COFI/LAC’s opinion. Unlike with volumetric usage, customers cannot act to reduce their bills in response to a high fixed charge. Even if a customer does understand that lower usage may eventually, theoretically lead to lower delivery service costs for NS and PGL, COFI-LAC argue the chain of proximate cause between customers reducing their usage and the Companies voluntarily asking this Commission for a lower customer charge at an unspecified point in the future is so remote as to be non-existent.

COFI/LAC concur with the AG that the Commission should adopt a rate design that recovers no more than 50% of its heating revenue requirement for both PGL and NS in order to be consistent with recent Commission decisions, the State’s energy policies, and the fact that the Companies are assured recovery of their revenue requirement through the decoupling rider, Rider VBA. AG IB at 72, citing AG Ex. 4.00 at 19–20; COC IB at 61-65.

COFI/LAC ask that the Commission view the Companies’ proposed customer charge increases as negatively as it did Peoples Gas’ and Ameren’s requests in 2015—particularly given the Companies’ VBA riders. COFI/LAC urge the Commission to reject these proposed customer charge increases, reduce the percentage of revenues collected
through the customer charge consistent with AG witness Larkin-Connolly’s recommendation, and otherwise adopt City witness Rabago’s proposal for evenly splitting revenue collection sources.

f. PIOs’ Position

In this case, Peoples Gas proposes to raise its residential fixed charge—the portion of the bill customers cannot change even if they use zero gas—from $30.84 to $44.76 per month. PGL Ex. 7.0 at 11. PIO note that the Company’s residential fixed charge is already the highest in the state. Its proposal would vault its fixed charge far above most other Midwest utilities. PIO Ex. 1.0 at 110.

PIO request that the Commission reject the Company’s proposal here, just as it rejected its proposed fixed charge in Peoples Gas’ most recent rate case. They maintain that Peoples Gas’ proposed fixed charge would undermine the state’s efficiency and conservation objectives, because it would reduce customers’ incentive to invest in reducing their gas use. PIO witness Cebulko explains: “Because gas rates are a zero sum game, customer charge increases are offset by decreases to the volumetric charge. Decreases to the volumetric charge reduce customers’ ability to control their bills by adjusting their usage, thus reducing the incentive to conserve energy or invest in energy efficiency.” Id. at 108. PIO note that the Commission has recognized the relationship between high fixed charges and customers’ incentive to invest in energy efficiency: in the Company’s last rate case, the Commission stated that high fixed charges “are inconsistent with 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.” Docket No. 14-0224/0225, Order at 176 (Jan. 21, 2015).

PIO explain that a high fixed charge also penalizes low-usage and low-income customers. That is because, all else equal, the fixed charge represents a relatively large portion of those customers’ bills. As PIO witness Cebulko testifies, “[l]ow-income households have higher ‘energy burdens,’ meaning that they spend a disproportionate amount of their income on energy bills.” PIO Ex. 1.0 at 112. A higher fixed charge “would disproportionately increase energy bills for the customers who are already spending a disproportionate share of their income on energy, further limiting the resources that such customers have to spend on food, housing, health expenses, and other essentials.” Id. at 112.

PIO note that the Company’s chief justification for its proposal is that its proposed fixed charge follows its ECOSS and recovers 100% of those costs that are classified as “customer-related” costs through its fixed charge, consistent with the Commission’s directives in its last rate case (Docket Nos. 14-0224/0225 (cons.)). Staff recommends approval of the Company’s proposed fixed charge on largely the same basis. Staff Ex. 5.0 at 27-28.

PIO assert that the Company and Staff overstate the relevance of the Commission’s determination in Peoples Gas’ 2014 rate case to its determination here. They explain that the Commission is not bound by its prior decisions and has the power to change course in this proceeding. The Commission is free to reverse its decision in any prior docket because it “is not a judicial body and its orders do not have the effect of res judicata; the Commission, as a regulatory body[,] must have the authority to address
each matter before it freely, even if it involves issues identical to a previous case.” Lakehead Pipeline Co. v. Ill. Com. Comm’n, 296 Ill. App. 3d 942, 956 (3d Dist. 1998)

Here, PIO maintain that the Commission should consider both whether a smaller portion of Peoples Gas’ “customer-related” costs should be recovered through the fixed charge, and whether Peoples Gas is subjectively misclassifying certain costs as “customer-related” when they are more appropriately classified as “demand-related” costs. In particular, the Commission should reject the Company’s classification of service lines as “customer-related”. As Peoples Gas witness Nelson acknowledges, the cost of service lines varies with customers’ demand. NS-PGL Ex. 6.0 at 16. In rebuttal, witness Nelson again testifies that service line costs are not identical for each customer, instead varying based on operating pressure and pipe diameter. NS-PGL Ex. 16.0 at 10-11. This testimony supports the classification of service line costs as “demand-related”, not “customer-related.” As PIO witness Cebulko explains, “service pipe diameter varies with demand requirements, not the number of customers served by a service line.” PIO Ex. 4.0 at 48. The costs of Peoples Gas’ service line allowances alone increases its monthly customer charge by $16.69—equivalent to many other Midwest utilities’ entire fixed charge. PIO Ex. 1.0 at 110; PIO Ex. 1.2 at 45-50 (Company Response to PIO 5.15).

ELPC submits separate briefing that addresses Peoples Gas’ residential fixed charge in greater detail. Consistent with ELPC, PIO recommends the Commission reject Peoples Gas’ proposal to increase its residential heating customer fixed charge, and reduce that fixed charge to no higher than $24.86 per month.

g. AARP’s Position

AARP strongly opposes the Peoples Gas proposal to raise the fixed charges on residential customers’ bills. The current fixed charges of Peoples Gas are already outrageously high at $30.84 per month for heating customers. The Company now proposes in this case to raise that fixed part of the bill by 45% higher through a daily fixed charge of about $44.00 per month. AARP believes that such high fixed charges would send the wrong price signal and would be contrary to the public interest in several ways.

PIO witness Cebulko recommends decreasing the customer charge to $24.86/month (or $0.81739/day) to better reflect cost causation and move in the direction of more efficiently achieving state policy goals. The City recommends that the Commission adopt the “basic customer method” for developing its fixed customer charges, or alternatively, an approach that limits fixed charges to no more than 50% of all distribution costs. COC Ex. 2.0 at 41-49. AARP supports these recommendations on cost causation grounds, believing that fixed charges should only reflect those utility costs that are customer-specific or “customer caused”, such as billing, customer service, and the line to the house. A fixed customer charge of $24.86 would more than adequately cover those customer costs. In the previous Peoples Gas rate case, the Commission recognized these policy concerns, finding the following:

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.

Docket No. 14-0224/14-0225 (cons.), Order at 175-176.

As the City witness Rabago points out, the utility’s approach would charge all the customers in the residential heating class the same averaged fixed customer charge, “despite there being a wide range of demand-induced costs generating that fixed customer charge. Small users with low connection costs are therefore required to subsidize the customer connection costs of higher-demand customers. This is not just or reasonable and is not consistent with Commission-recognized rate design policies that attribute costs to cost causers, encourage energy efficiency, and eliminate inequitable cross-subsidization of high users by low users of gas.” COC Ex. 2.0 at p. 24.

Moreover, there are public policy considerations that should be incorporated into the Commission’s reasoning on the proper residential rate design. The utility itself will not be financially harmed by whatever balance is struck between fixed charges and volumetric charges, as the rates overall will be designed to reach whatever revenue requirement the Commission ultimately adopts. If Peoples Gas is allowed to increase fixed fees ever higher, then low usage residential consumers, including many households with older residents, will be financially harmed on a relative basis. Low usage customers will also experience a much higher percentage increase as a result of this rate case than the average residential customer. AARP asks that the Commission give due consideration to protecting small usage customers when determining this issue, many of whom are vulnerable and have little to no extra means to pay for the disproportionate bill impacts that high fixed charges impose upon them.

Perhaps the most direct rate design consideration in this regard is the harmful impact of high fixed charges on the ability to control one’s energy bills. AARP explain that if unavoidable fixed charges constitute the majority of a customer’s gas distribution charges each month, then there is little that a customer can do to react to such increases. The higher the fixed charges, the lower the financial rewards a consumer can experience from engaging in energy conservation or energy efficiency measures. Peoples Gas’ plan for ever higher fixed charges would discourage energy conservation and energy efficiency, and would thus impede many Illinois state energy goals. COC Ex. 2.0 at 8.

AARP assert that high fixed charges are also regressive, because there is a high correlation between low usage rates and lower household incomes. Id. at 29-30. Many households with seniors in the Chicago area live with very high energy burdens and in a state of energy insecurity. City witness Rabago explains high energy burden as when “a very high percentage of household income is devoted to getting essential energy services. Because of such high energy burdens, these people are at risk of losing access to service or having to forego other essential goods and services if they experience even modest interruptions in household income.” Id. at 31. AARP urges the Commission to protect those vulnerable customers by adopting fixed charges for natural gas heating customers in this case no higher than $24.86.
h. ELPC’s Position

According to ELPC, Peoples Gas supports the requested 45% increase in the customer charge with the very arguments that the Commission rejected in the 2014 rate case. The objectives Peoples Gas provides to justify the proposed rate design in this case are nearly verbatim to the objectives the Company provided in the 2014 rate case. In this rate case, Peoples Gas states that the Company’s rate design objectives for this case are to: (1) recover Peoples Gas’ revenue requirement, (2) align rates and revenues with underlying costs, (3) send the proper price signals, (4) provide equity between and within rate classifications, and (5) reflect gradualism considering test year revenue requirements. PGL Ex. 7.0 at 5.

In the 2014 rate case, Peoples Gas likewise provided a list of stated objectives to support the Company’s rate design. The Commission summarized the stated objectives in that case as follows: (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. Docket No. 14-0224/14-00225, Order at 152. ELPC notes that there was a sixth objective in the 2014 Rate Case relating to distribution block structures that is not relevant to the residential rate design in this case.

ELPC points out that the 2014 rate case Order rejected Peoples Gas’ argument that the best way to accomplish these objectives is through a high customer charge. In fact, with respect to several of these goals, the Commission found that a lower fixed charge would be more effective.

ELPC states that in this case, Peoples Gas makes the overlapping assertions that (1) the Company needs to raise the fixed customer charge in order to ensure cost recovery and (2) the proposed rate design will “align rates and revenues with underlying costs.” PGL Ex. 7.0 at 5. The 2014 Peoples rate case Order directly rebuts those points. In that Order, the Commission explained 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.” Docket No. 14-0224/14-00225, Order at 176. The Commission accordingly “reject[ed] the Companies’ claim that customer charges must be raised to ensure cost recovery.” Id. at 175. The Company still maintains decoupling, uncollectibles, and infrastructure riders. As the Commission explained when it approved decoupling in the Company’s 2007 rate case, the Company’s decoupling rider “adjust[s] customer prices . . . in a way that . . . revenues are held constant despite changes in customer consumption.” Docket No. 07-0242, Order at 138 (Feb. 5, 2008). Hence, Peoples Gas does not need to raise the customer charge to align revenues with costs.

ELPC states that while Peoples Gas fails to adequately address this issue, intervener testimony raises precisely the same concerns of cross-subsidization that the Commission addressed in the 2014 rate case. City witness Rábago provides data demonstrating how the Company’s rate design hits low-use customers the hardest. As Mr. Rábago explains, the data “shows that the average rate per therm for a customer using 20 therms per month is $1.77, which is three times higher than the effective rate for
an average customer, who uses 86 therms per month, at $0.52 per therm.” COC Ex. 2.0 at 26. AG witness Larkin-Connolly likewise testifies that low-use customers “pay exceedingly more per therm with a high fixed charge than when the fixed charge is lower.” AG Ex. 4.00 at 15.

i. Commission Analysis and Conclusion

The Commission declines to adopt the Companies’ proposed increase in the fixed customer charge. The Commission is concerned with the impact that this proposal could have on low-income customers and its failure to recognize the Commission’s energy efficiency goals. Rather, the Commission will require PGL to collect no more than 39.06% of its residential heating revenue requirement through the customer charge. This percentage reflects the amount PGL’s current fixed customer charge for residential heating customers, $30.84, would recover as a proportion of PGL’s proposed residential revenue requirement. Similarly, the Commission finds that PGL should collect no more than 62.28% of its residential non-heating revenue requirement through its fixed charge, reflecting the amount PGL’s current fixed customer charge for residential non-heating customers, $16.37, would recover as a proportion of PGL’s proposed residential revenue requirement. Based on the AG’s recommendation, the Commission orders North Shore to collect no more than 50% of its residential heating revenue requirement, and no more than 70% of its residential non-heating revenue requirement, through its fixed customer charge.

Given the disallowances found in this Order, the Commission finds this proportional approach to be an appropriate middle ground to address the fixed charge concerns raised by many intervenors, without over-inflating the volumetric charge. This proportional approach ensures that customers who use more gas pay more and encourages customers to use less natural gas in furtherance of the State’s clean energy goals. The proportional approach also limits the burden on low-usage customers, who are more likely to be low-income customers, and advances the State’s equity and affordability policies articulated in CEJA. 220 ILCS 5/16-108.20(a) (“The General Assembly finds that it is critical to maintain…focus on utility bill affordability as the State transitions to a clean energy economy.”). The Commission notes that the City recommends further gradual reductions to the customer charge, but the Commission declines to adopt that proposal because it is based on the City’s concerns with the ECOSS which the Commission rejected.

The Commission finds that the Companies’ risk of not recovering their authorized revenue requirement is minimal in light of the guaranteed revenue recovery that the Companies enjoy through Rider VBA, their revenue decoupling riders.

As the Commission is approving a different revenue requirement than that proposed by the Companies, NS and PGL are directed to make the necessary adjustments to the appropriate ECOSS accounts and allocation factors. The Companies are further directed to submit ECOSSs that are based on the Commission’s Order as compliance filings.
2. Low Income Discount
   a. Companies’ Position

   The Companies note that in December 2022, the Commission directed certain gas and electric utilities to propose a low-income discount rate with their next rate case filings consistent with new changes to Illinois law. Pursuant to this directive, the Companies each propose establishing Rider LIDA, Low Income Discount Adjustment, under which eligible low-income customers will receive a Low Income Discount Credit (“LIDC”) on their bills. NS Ex. 7.0 REV at 17-18; PGL Ex. 7.0 REV at 22. Staff and various intervenors also offered low-income discount proposals. The Companies’ proposal incorporates many of Staff’s recommendations and should be accepted. The Companies argue it is cost effective, raises fewer operational issues than intervenors’ proposals, and focuses on helping those who could benefit most from a low-income discount program.

   *The Companies’ Proposal*

   Under the Companies’ proposal, customers eligible for the LIDC will be residential customers with income levels at or below 300% of the Federal Poverty Level (“FPL”) and/or who qualify for Low Income Home Energy Assistance Program (“LIHEAP”) or Percentage of Income Payment Plan (“PIPP”) benefits as determined by the LIHEAP administrator and the Companies. NS-PGL Ex. 28.2 at 1, 6. As Staff proposed, the Companies’ program will have three tiers that will be applied to the customer charge component of the bill. The eligibility criteria and the discounted amounts for each LIDC Tier are shown below:

<table>
<thead>
<tr>
<th>Tier</th>
<th>Eligibility Limit for Tiers</th>
<th>Daily LIDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tier 1</td>
<td>0 – 100% of Federal Poverty Level</td>
<td>100% of Customer Charge</td>
</tr>
<tr>
<td>Tier 2</td>
<td>Over 100% of Federal Poverty Level – LIHEAP/PIPP Limit</td>
<td>75% of Customer Charge</td>
</tr>
<tr>
<td>Tier 3</td>
<td>Up to 300% of Federal Poverty Level</td>
<td>25% of Customer Charge</td>
</tr>
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   *Id.* at 5, 10.

   The Companies will work with the LIHEAP administrator to determine eligibility for Tier 1 and Tier 2. *Id.* at 1, 6. Tier 3 can be self-reported by the customer to the company via the application provided on the company’s web page, by fax, or by mail. *Id.* For Tier 3, qualification will be effective when the company receives the completed application. *Id.*

   The Companies accepted Staff’s proposal to use percentage discounts rather than fixed credit amounts because percentage discounts alleviate the need to “carry over” credit balances. Further, applying the percentage discount to the customer charge complies with a requirement of the Commission’s Low Income Discount Rate Study Report to the Illinois General Assembly. NS-PGL Ex. 28.0 at 4.
The Companies explain that expenses resulting from the LIDC will be recovered from all customers. For North Shore, this means S.C. Nos. 1, 2, 4, 5, and 7; for Peoples Gas, this means S.C. Nos. 1, 2, 4, 5, 7, and 8. NS Ex. 7.0 REV at 18; PGL Ex. 7.0, at 22. The LIDC will be effective April 1 through March 31 and will be displayed on bills as a separate line item labeled as “Low Income Discount Adjustment.” NS-PGL Ex. 28.2, 1, 6. However, the initial effective period will be from October 1, 2024 through March 31, 2025. Id.

No later than June 30 of each year, the Companies state they will file petitions to reconcile the revenues collected during the effective period with the actual total LIDCs applied.

Response to Intervenors’ Proposals

The Companies note that COFI/LAC, PIO, and the AG submitted low-income discount proposals. They generally want a higher discount than the one proposed by the Companies and Staff. COFI/LAC witness Colton proposed a five-tier program of discounts for customers with income tiers between below 50% of FPL up to 300% of FPL. NS-PGL Ex. 17.0 REV at 7. AG witness Larkin-Connolly proposed a similar five-tier discount with differing discounts that would apply to a participating customer’s total bill. AG Ex. 8.0 at 48. PIO witness Schott proposed a two-tier credit applicable to the customer’s total bill. NS-PGL Ex. 17.0 REV at 9. The first tier would be for customers under 30% State Median Income (“SMI”) with a 75% credit or discount. The second tier would be for customers with a 30%-60% AMI for a 25% credit or discount.

It is the Companies’ position that the intervenors’ varying tiered proposals should be rejected in favor of the three-tiered system that Staff proposed and the Companies accepted. COFI/LAC’s and the AG’s five-tiered systems would be overly complex and administratively burdensome. NS-PGL Ex. 17.0 REV at 7. They would require the Companies to make a variety of changes to their IT system and billing process and necessitate developing processes to identify customers eligible for certain tiers beyond the LIHEAP/PIPP levels, increasing costs and implementation time. NS-PGL Ex. 31.0 at 6. In contrast to both the five-tiered and two-tiered proposals, the Companies’ point out that their three-tiered system would maximize low-income customer participation while balancing the administrative and IT hurdles the Companies would face in implementing the LIDC. Id. at 8.

The Companies add that the intervenors’ proposals would also impose significant cost burdens on non-participating customers. NS-PGL Ex. 17.0 REV at 7-8, 11. And their applications of the discount to the total bill would fail to comply with the Commission’s determination that discount rates should only apply to delivery service charges. Staff Ex. 14.0 at 14; NS-PGL Ex. 28.0 at 6.

The intervenors’ concern for and advocacy on behalf of low-income customers is notable according to the Companies. But the Companies state that the reality is that customers who do not receive the LIDC will be responsible for paying for it. NS-PGL Ex. 12.0 at 23. Thus, the Companies (and the Commission) have to balance competing interests, and they have to do so in a way that results in just and reasonable rates. The Companies note that they have a number of existing programs to help low-income customers, and their LIDC proposal will be one more way to assist these customers. Id.
at 22. It is consistent with statutory requirements and will be effective. *Id.* at 23. By reducing the customer charge, low-income customers will have greater control of their monthly natural gas bills, as Staff witness Moushon testified. Staff Ex. 14.0 at 15.

The Companies maintain that Mr. Larkin-Connolly's suggestion that the costs of Rider LIDA should be combined and allocated over both Companies is inappropriate. The Companies are separately incorporated and are two separate utilities under the Act with their own Commission-approved tariffs of service. Cross-charging would create a potential for impermissible cross-subsidization in violation of the Act. The Companies note that the Commission has repeatedly rejected attempts to cross-subsidize costs. In the Companies' 2015 Rate Case, the Commission rejected a proposal to allocate the same percentage of revenue deficiency across all service classifications regardless of what the Companies' ECOSSs showed, because doing so would create cross-subsidization across service classifications as opposed to cost-based rates. Docket Nos. 14-0224/0225 (cons.), Order at 157-158; *see also Ill. Gas Co.*, Docket No. 98-0298, 1998 WL 34302600 (Sept. 10, 1998) (supporting eliminating cross-subsidization between rate classes).

The AG also urges the Commission to adopt a single program for all utilities—allegedly to "facilitate customer communication, adoption, and implementation." The Companies assert this position is unsupported. There is no requirement that utilities implement the same rates and there is no support in this record for the idea that another utility’s proposal is more appropriate than the Companies' proposals.

The Companies observe that implementing Rider LIDA will take time and come with costs. The Companies will need to change their tariff books' Table of Contents and sample bills and add Rider LIDA to the "Base Rates" definitions within the Rider ICTA, Invested Capital Tax Adjustment and Rider VITA, Variable Income Tax Adjustment tariffs and to the adjustment amounts for delivery service within the Rider UEA tariff. NS Ex. 7.0 REV at 19-20; PGL Ex. 7.0 REV at 24. Further, as indicated above, IT and billing changes are needed, increasing the time and cost for implementation. NS-PGL Ex. 31.0 at 6, 10-11.

Staff witness Moushon recommends that the Companies file a low-income rate design in their next filed rate case. Staff Ex. 14.0 at 12. The Companies state that they are not opposed to having a low-income rate design, but recommend that any rate design would be implemented no sooner than a general rate proceeding filed six months after the first report filed with the first annual reconciliation of Rider LIDA. NS-PGL Ex. 17.0 REV at 13. The first reconciliation of Rider LIDA will be filed by June 30, 2025. *Id.* at 13. The Companies believe that there is a need to get sufficient data from Rider LIDA's operation prior to making a decision on rate design. *Id.* at 13.

**b. Staff’s Position**

Staff asserts that the Commission should approve its proposed low-income discounts and Rider LIDA with agreed modifications proposed by the Companies and accepted by Staff witness Moushon. *See NS-PGL Ex. 28.2.*

*Staff’s Proposal*
Staff explains that its proposal consists of a three-tiered low-income discount that would reduce the Customer Charge for Heating and Non-Heating residential customers based on eligibility determined by household income as a percentage of the FPL. Staff Ex. 6.0 at 9. The Tiers consist of 0 – 100% of FPL for Tier 1, 100% of FPL -LIHEAP/PIPP limit for Tier 2, and up to 300% of FPL for Tier 3. Eligibility for Tiers 1 and 2 is to be reported by the LIHEAP administration and Tier 3 can be self-reported by the customer. Id. at 9-10. The proposed discounted amount for each Tier is: Tier 1, 100% of the Customer Charge, Tier 2, 75% of the Customer Charge, and Tier 3, 25% of the Customer Charge. Staff Ex. 14.0 at 13.

Staff’s proposal also requires the Companies to periodically, but at least every twelve (12) months, verify eligibility through sampling 5% of the eligible Tier 3 customers, or 200 Tier 3 customers, whichever is greater. Staff Ex. 6.0 at 9-11; Staff Ex. 14.0 at 13. Staff recommended an effective date of October 1, 2024, which is approximately nine (9) months from the date the Final Order in this case is expected. Staff Ex. 14.0 at 10. Additionally, Mr. Moushon recommended that the Companies provide status reports on the Rider LIDA program implementation to the Commission every three months until the program is implemented. The proposed implementation reports would include, at minimum, the following:

1. A summary of actions taken by the Companies to implement the low-income discount program during the reporting period;
2. Itemized list of implementation costs during the reporting period;
3. A summary of the Companies progress toward 100% implementation (may be expressed in percentages); and
4. Projected completion date for implementation of the low-income discount program.

Id. at 10 -11.

Staff recommends that the Companies be required to submit, at minimum, a rate design proposal that includes at least one low-income rate class at the time of the next general rate case proceeding. Staff Ex. 6.0 at 16. Further, Staff recommends reporting requirements for the low-income discount program. Staff recommends reporting requirements are as follows:

1. The number of participants enrolling in each Tier for each month of the preceding year by zip code;
2. The billed usage in each Tier for each month of the preceding year by zip code;
3. Itemized list of administrative costs incurred to implement and operate Low Income Discount Program for each year since approval of program;
4. Description of education and outreach materials (copies of those materials, where applicable);
5. Data on processing time for Tier 3 eligibility from initial request to approval under each of the options available to customers requesting the Tier 3 credit (online, by phone, by mail); and
6. Detailed description of the sampling technique used to verify eligibility of Tier 3 discounts/credits using 5% threshold specified in the tariff, or 200 customers, whichever is greater, and results of the review/audit including, but not limited to, the number of customers within the 5% of customers sampled that were unable to meet the income requirement or the income verification requirement. 

_id_. at 14-15; Staff Ex. 14.0, Attach. 14.01.

In response to Staff’s recommended changes to the Companies’ Rider LIDA proposals, Companies witness Eglehoff stated the requirement to apply discounts as credits to only the delivery charges as defined would cause undue burden and costs for the Companies to implement. NS-PGL Ex. 17.0 at 6. Staff notes that Companies witness Baron also raised concerns that the credits carrying over to the next monthly bill for households where the initial credit is greater than the bill delivery charge would be challenging because the process goes beyond the ability of the current billing systems; it would require customization of the systems; and it would add complexity. NS-PGL Ex. 20.0 at 14. Mr. Baron also disagrees with Staff’s proposed self-reporting eligibility process to the Companies for Tier 3. Thus, Mr. Baron proposed verifying the income information at the time of application through the same process the Companies currently use to certify low-income customers to be excluded from late payment charges, as well as recertification annually. _id_. at 11. Mr. Baron also estimated the implementation time for Staff’s proposal (as outlined in Staff Ex. 6.0) from the date of the Commission Final Order would be at least 18 months.

In surrebuttal testimony, the Companies agreed with Staff’s proposed Rider LIDA in NS-PGL Ex. 28.1, with slight modifications to the tariffs as accepted by Mr. Moushon in Staff Ex. 14.0. NS-PGL Ex. 28.0, 4. Ms. Eglehoff stated that while the Companies continue to believe that it would be reasonable for enrollment in Tier 3 to review income eligibility, similar to the requirement for Tier 1 and Tier 2 status For Tier 1 and Tier 2, customers apply to local administering agencies that will verify income and confirm eligibility. However, to narrow the issues in this case, the Companies agreed that no Tier 3 customer income verification needs to be conducted for enrollment. _id_. at 5.

The Companies agreed to accept Mr. Moushon’s recommended proposal for a three (3) tiered proposal implementing percentage-based discounts that would be applied only to the Customer Charge and would not need to be carried over to the next month. The Companies also agreed to accept Mr. Moushon’s recommended proposal for Tier 3 applicants automatically enrolled in the Low-Income Discount Program at the time their applications are completed. The Companies accept the October 1, 2024 implementation date and agree to provide status reports on the implementation of Rider LIDA every 3 months until the program is implemented. NS-PGL Ex. 31.0 at 3. Staff notes that Rider LIDA, with modifications agreed to by Staff and the Companies, is provided in NS-PGL Ex. 28.2.

(Response to COFI/LAC’s Proposal)

Staff states that COFI/LAC witness Colton presented a five-tier customer proposal, which provides discounts to the customer’s total bill and does not meet the provisions of the Commission’s directive in the Low-Income Report. Additionally, COFI/LAC oppose the number of tiers and the corresponding discount levels provided for in Staff’s LIDR
propose. COFI/LAC also oppose Staff’s proposal to have the discounts applied to the customer charge only. *Id.* Instead, COFI/LAC recommend the Commission approve their proposed five tiers of discounts that would be applied to a residential customer’s whole bill. *Id.*

Staff argues the Commission should reject COFI/LAC’s proposal for several reasons. First, COFI/LAC criticize all other LIDR proposals, except its own, for not providing an “affordability assessment.” COFI/LAC IB at 30. The affordability assessment COFI/LAC provide centers on using a 3% energy burden to determine discounts on total bills for various income levels. *Id.* However, Staff states COFI/LAC disregard the Commission’s recommendations in the Commission’s December 2022 Low-Income Discount Rate Report. Specifically, the Commission’s recommendations did not require using a 3% energy burden threshold; rather, the Commission recommended discounts be applied to delivery service charges only (Illinois Commerce Commission, Low-Income Discount Rate Study Report to the Illinois General Assembly, Dec. 2022 at 8 (“the Low-Income Report”), which is the approach used in the low-income proposal agreed upon between the Companies and Staff. Additionally, Staff notes that the Companies’ estimate there would be a significant cost associated with the five eligibility tiers that COFI/LAC propose. Importantly, COFI/LAC have not demonstrated that the benefit to low-income customers would exceed the cost of their 5-tier discount proposal.

Second, COFI/LAC attempt to justify their proposed five tier discount structure by noting that customers with incomes <50% of the FPL have energy burdens that are nearly twice as high as those with incomes between 50 – 100 % of the FPL. COFI/LAC IB at 33. Staff’s proposal addresses the concern raised by COFI/LAC by applying the maximum discount to the delivery service charges (100% of the customer charge) to eligible customers with income up to 100% of the FPL. Staff IB at 121-122. Additionally, Staff’s proposal would provide discounts for the same income ranges as proposed by COFI/LAC – i.e., zero to 300% of the FPL. COFI/LAC IB at 27. The Companies also provided feedback, Staff notes, regarding the implementation of higher amount of tiers as in COFI/LAC’s proposal, noting that five tiers would be “overly complex and administratively burdensome” and would require a variety of changes to the IT system and billing process. NS-PGL IB at 191. Thus, it follows according to Staff that its proposal actually has a lower projected administrative cost and a shorter implementation timeline than the COFI/LAC proposal.

Third, COFI/LAC also incorrectly assert that its proposed LIDR discounts will result in fewer collection costs. COFI/LAC IB at 34. As previously stated, Staff’s proposal provides the highest available discount to the lowest income brackets. Staff surmises that it follows that Staff’s proposal would also reduce the collection costs by providing LIDR discounts to the same income brackets (i.e., zero – 300% of FPL) as proposed by COFI/LAC.

**Response to the AG Recommendations**

Staff notes that the AG did not provide a proposal, but states as a general recommendation, the Commission should adopt discount rates for all four gas companies with ongoing rate cases that are similar with aligned eligibility criteria, discounts, and recovery methods. The AG specifically recommends that COFI/LAC’s proposal be
modified to provide the same percentage discounts that COFI/LAC proposed in the ongoing Nicor rate case. *Id.* at 77. Staff argues the Commission should reject the AG’s position as it disregards the Commission’s recommendations in the Low-Income Report.

**Response to PIOs’ Proposal**

Staff contends that PIO witness Schott’s proposal, which provides discounts to the customer’s total bill, does not meet the provisions of the Commission’s directive in the Low-Income Report. Staff notes that PIO argues that the Act permits the Commission to adopt a total bill discount. Specifically, PIO states that, “The Commission has the authority to adopt the PIOs’ low-income discount rate pursuant to Section 9-241. While the Commission’s Low-Income Report concludes discounts ‘are applicable only to the delivery service charges’, nothing in Section 9-241 limits the Commission’s discretion to flat rate discounts or discounts that apply only to delivery charges.” PIO IB at 59.

Staff urges the Commission to reject PIOs’ argument. PIO is correct that there is no limiting language in the Act; however, while making that argument, PIO ignores the plain language of the Act. The Act specifically states that the Commission “shall conduct” a comprehensive study to assess whether low-income discount rates are appropriate and the potential design and implementation of those rates. 220 ILCS 5/9-241. Upon completion of the study, the Commission “shall have the authority to permit or require” utilities to file a tariff establishing low-income discount rates. 220 ILCS 5/9-241. The Section then goes on to discuss what the study must assess.

Pursuant to the Act, the Commission conducted the comprehensive study and upon completion of the study, the Commission issued the Low-Income Report to the Illinois General Assembly. Staff highlights that Section VIII (2) of the Low-Income Report states that, “All such utility low income discount rate and proposals should include tiered discounts for different income levels, which are applicable only to the delivery service charges.” Low-Income Report at 63 (emphasis added).

Staff also highlights that Section 9-241 of the Act gives authority to the Commission to permit or require low-income discount rates after conducting the comprehensive study and submitting the Low-Income Report to the Illinois General Assembly. Staff argues that it is clear that the low-income discount rates adopted by the Commission should be consistent with the Low-Income Report that was issued as a result of Section 9-241 of the Act.

Therefore, Staff concludes that the Commission should approve its recommendations, which are consistent with the study conducted pursuant to the Act. And reject PIOs’ argument that the discount should be applied to the total bill, which is in conflict with the Commission’s conclusions in the Low-Income Report.

c. **AG’s Position**

The AG notes that in accordance with the Commission’s Low-Income Report, North Shore and Peoples Gas proposed to modify their Rate 1—Residential Service rates to include a discount rate for low-income customers. The AG further notes that Staff, COFI/LAC, and PIO each offered alternative proposals.

The AG ask the Commission to approve the low-income discount rate proposed by COFI/LAC witness Colton, as modified by AG witness Larkin-Connolly, because it
provides the most equitable and effective discount for low-income ratepayers. The AG also recommends that the Commission adopt discount rates for all four gas companies with ongoing rate cases that are similar “with aligned eligibility criteria, discounts, and recovery methods, which would facilitate customer communication, adoption, and implementation.” AG Ex. 4.00 at 25-26.

The Companies, the AG states, generally argue that the Commission should reject all of the alternative proposals because the implementation and other costs of these would be too high. The AG contends that the Companies’ arguments are meritless. As to implementation and program costs, the AG argues that the Commission should disregard the Companies’ claims that the AG’s discount rate proposal would overburden other customers. This critique contains two separate issues: (1) administrative costs and time to implement the program and (2) the ongoing costs of the program. Regarding implementation costs, the Companies state that Staff’s rebuttal proposal (which the Companies adopted in surrebuttal) could be implemented for between $25,000 and $37,000. PGL Response to AG DR 15.12 (AG Cross Ex. 3 at 3). The Companies, despite having the opportunity, decline to provide any estimate for the implementation costs for the AG’s and COFI/LAC’s proposals. Id. at 3–4. Therefore, the AG iterates that there is nothing in the record to support the Companies’ complaint that the costs would be “significant[ ]” other than their own vague statement. According to the AG, what the record does show is evidence that the AG’s modified COFI/LAC proposal would bring about transformational support and that they result in minimal impact on the Companies’ overall revenue requirements. AG Ex. 4.00 at 36-37, 40-42. Given this, the AG claims the Companies allegation that the COFI/LAC’s discount program implementation costs “significantly” exceed $25,000–$37,000 should be disregarded by the Commission. As to overall costs of the program, the AG also refutes the Companies’ argument that the intervenors’ proposals “would also impose significant cost burdens on non-participating customers.” NS/PGL IB at 192. The AG states that the record evidence undeniably shows that PGL and NS customers are struggling to pay their bills.

The Companies also took issue with the intervenors’ proposals that the discount apply to customers’ entire bills, noting the intervenors’ “application of the discount to the total bill would fail to comply with the Commission’s determination that discount rates should only apply to delivery service charges.” NS/PGL IB at 192. The AG responds that it does not believe the Low-Income Report is the Commission’s final word on discount rates, but a tentative or first step toward enacting low-income discounts. According to the AG, the Commission did not address the issues that other parties could raise, nor did it limit what type of programs the Commission could consider in a docketed proceeding or adopt in an evidentiary proceeding like this one. The AG asserts that nothing in the Low-Income Report or the Act limits the Commission’s authority to adopt a discount program that applies to customers’ entire bills. To support its position, the AG notes that the Commission received comments from Staff, utilities, and other stakeholders, including the AG, and compiled these comments into the Low-Income Report. It is evident that the Low-Income Report was not a final order from a docketed adversarial proceeding, but a series of tentative, first step suggestions based on a limited comment period. Moreover, the AG argues that the current case provides the Commission the opportunity to receive and assess evidence on which discount program will best benefit the Companies’ low-income customers at a reasonable cost to other ratepayers.
The AG refers to PIO witness Schott, who testified that “[i]t is not possible to achieve an affordable gas burden for the lowest income customers by discounting only the delivery charges.” PIO Ex. 6.0 at 11. The AG opines that this means that adopting full bill discounts like those proposed by the AG, COFI/LAC, and PIO would bring low-income customers closer to an affordable 3% energy burden. The AG argues that its proposal achieves the goal of a transformational full-bill discount to low-income customers at an estimated cost of approximately $16–36 per year to the average residential customer. The AG urges the Commission to adopt this proposal in light of the evidence provided in this proceeding and not arbitrarily limit the discount to delivery charges.

The AG’s Recommendations

The AG explains that Mr. Larkin-Connolly recommended that COFI/LAC’s proposal be modified to provide the same percentage discounts that Mr. Colton provided in the Nicor rate case: Tier 1 – 75%; Tier 2 – 55%, Tier 3 – 25%, Tier 4 – 10%, and Tier 5 – 5%. Id. at 22, ref. Docket No. 23-0066. According to Mr. Larkin-Connolly, applying this approach can ensure that the discounts are consistent across all four ongoing natural gas rate cases and reduces the costs of COFI/LAC’s PGL proposal by approximately $19 million per year and COFI/LAC’s NS proposal by approximately $815,000 per year. Id., see id. at 41: Table 4; see also AG IB at 78.

The AG states that Mr. Larkin-Connolly’s modification to COFI/LAC’s proposal applies a percentage discount to the total bill and therefore would provide a meaningful discount to all low-income customers, rather than to the subset of low-income, low-usage customers who may benefit from the fixed discounts proposed by the Companies and Staff. Id. at 29. According to the AG, this discount, coupled with the AG’s proposed residential rate design, could lead to a meaningful bill reduction for all low-income customers, and all residential customers generally, except for the highest usage customers. Id. In combining these two proposals, the AG asserts that the Commission can ensure that the Companies’ rate design is consistent with the state’s clean energy policies, while protecting high-usage, low-income customers who may have higher bills due to larger families or inefficient housing.

In addition to adopting this modified discount rate, the AG asks the Commission to adopt certain reporting requirements proposed by the Staff to track the progress of the program. Specifically, the AG ask the Commission to order the Companies to:

1. Use the five-tiered eligibility criteria for each tier as proposed by COFI/LAC, with the discounts for each tier proposed by Mr. Larkin-Connolly;
2. Recover the costs of the program through a new rider mechanism that is charged to residential and non-residential customers on a per therm basis;
3. Require the Companies to comply with the reporting requirements proposed by Staff witness Moushon and outlined in Staff’s LIDA Rider, Staff Ex. 6.0 at 15-16; and
4. Allow for customers at 200-300% of the FPL (Tier 5 in LAC-COFI’s proposal) to self-certify their participation, like Staff proposed in its LIDA Rider, Staff Ex. 6.01 at 4.

AG Ex. 8.00 at 48-49.
Response to the Companies’ and Staff’s Proposal

AG witness Larkin-Connolly noted that the costs of the program could be reduced for PGL customers if the collection of the program costs were combined for PGL and NS. *Id.* at 44. Under that scenario, he stated that the average PGL residential customer would pay $30.04 per year and the average NS residential customer would pay $36.41 per year toward the AG-modified program. *Id.* at 42: Table 5.

The AG notes that the Companies complain that such combined collection “would be inappropriate” because NS and PGL “are separately incorporated and are two separate utilities under the [PUA] with their own [Commission]-approved tariffs of service.” NS/PGL IB at 192. However, the AG notes that there are many inefficiencies and potentially duplicative costs associated with the Companies filing separately (despite routinely consolidating the matters as well as a loss of economies of scale). According to the AG, the record provides no evidence that would prohibit the Companies from collecting the program costs in a combined manner. The AG argues that the record shows only that such an approach would reduce what the average PGL residential customer would pay.

In addition, Mr. Larkin-Connolly testified that the recovery of these costs from both residential and non-residential customers is justified because commercial and industrial customers may have employees or customers who would be eligible for these discounts, and local businesses would also benefit from the increased affordability of gas services because low-income households will have more financial security and more disposable income available to spend on other goods and services. *Id.* at 47.

Additionally, the AG asserts that its modified COFI/LAC proposal is also preferable to the Companies’ proposals and Staff’s rebuttal proposal because it is not tied to the fixed customer charge. By tying their discounts to the fixed charge, the Companies and Staff effectively disincentivize any reduction in the fixed charge because the discount would fall with the fixed charge. AG Ex. 8.00 at 37-38. The AG believes the Commission should reject this approach because it would lock in the high-fixed charge structure used by NS and PGL, rather than moving to the AG’s and the City’s more equitable rate design approach.

d. City’s Position

The City is a strong supporter of the Commission’s decision to require that PGL provide a low-income discounted rate. The City urges the Commission to approve a low-income discount program that provides effective and equitable relief to low-income City residents. It is the City’s strongly held position that all Chicago residents should be able to have affordable energy bills, with the goal of a gas energy burden of no more than 3% of household income.

The City’s position is that PGL’s proposal for a low-income discount is not sufficient to provide the rate relief needed for low income PGL customers. In particular, PGL’s and Staff’s proposal would not apply to the entire gas bill but only to the fixed customer charge portion of the bill. Staff Ex. 14.0 at 13. The City agrees with the perspective of AG witness Larkin-Connolly that “when evaluating proposals for a low-income discount program the focus should first be on the potential effectiveness of the program to improve affordability
for low-income customers, and then the corresponding bill impacts of program costs on other customers.” AG Ex.8.0 at 26. The City contends that the low-income discount should apply as a percentage of the entire gas bill, including volumetric and commodity charges, in order to “address the substantial energy burden faced by families that are larger, need to heat more space, or live in less efficient residences.” See AG Ex. 8.0 at 38.

The City supports the proposals made by COFI/LAC and the AG to expand the reach of the low-income discount program, including a five-tiered discount to provide appropriately targeted assistance to those up to 300% of the Federal Poverty Level, applicable to the whole bill. The City appreciates COFI/LAC witness Colton’s emphasis on analyzing and crafting a proposal with a goal to limit low-income customers’ gas energy burden to no more than 3% of income. See, e.g., COFI-LAC 1.0 at 80-82.

The City urges the Commission to adopt the proposals made by COFI/LAC, in order to provide affordable gas rates to all while also promoting the efficient and conservative use of energy by all.

e. COFI/LAC’s Position

COFI/LAC note that this rate case is the first opportunity for the Commission to weigh in on the establishment of a low-income discount rate for PGL’s and NS’s financially struggling customers. The Commission must consider several competing proposals for the Companies’ newly-required LIDR, including COFI/LAC’s, PIOs’, and the Companies’. COFI/LAC state that NS and PGL oppose all of the proposals except Staff’s proposal in rebuttal and the Companies adopted Staff’s proposal on surrebuttal. NS-PGL Ex. 28.0 at 6. The AG generally supports COFI/LAC’s proposal, with modifications designed to assign a consistent level of discount to all customers across the state. AG Ex. 8.00 at 21-23.

COFI/LAC argue that their proposal will genuinely reduce low-income customers’ energy burdens to an affordable level and should be adopted. As discussed below, COFI/LAC’s LIDR tiered discount will cost-effectively apply specific discount levels to NS and PGL customers based on their income, with discounts applied to the entire bill – not just the customer charge, as Staff proposes. That approach serves the point of the creation of the discounted rate: to make bills meaningfully affordable for financially struggling customers, and to minimize arrearages and disconnections. It also serves the larger interests of ratepayers as a whole, who can be assured that the discounts being applied are neither too small (which increases uncollectibles) nor too large (an “overpayment” on the discounted rate). COFI/LAC assert that their low-income discount rate is the only proposal to truly address energy burden and improve the affordability of the Companies’ rates.

As the Commission assesses the various discount rate proposals in the record, COFI/LAC point out that it is critical that evidence of the unaffordability of Peoples Gas and North Shore Gas rates inform the selection of an appropriate low-income discount rate. Testimony and recent NS and PGL data filed with the Commission make clear that hundreds of thousands of the Companies’ residential customers cannot afford their bills each month, putting them at risk of disconnection, and forcing them to make difficult decisions about which life essentials they will go without, according to COFI-LAC. This
reality is documented by record evidence and NS and PGL credit and collections data filed with the Commission. It supports adopting the COFI/LAC proposal—the only one to address energy burden by ensuring rates do not exceed 3% of customers’ monthly incomes.

COFI/LAC provide extensive data that they insist demonstrates the Companies’ current rates are unaffordable. They contend that there are multiple indicators supporting their position that the Companies’ bills are unaffordable for a substantial portion of customers. Some of these indicators include:

- **Unprecedented PGL and NS arrearages.** The Companies’ reports of residential customer arrearages, as revealed in their monthly credit and collection reports filed pursuant to Section 8-201.10 of the Act, detail record-breaking levels of bills past due bills. AG Ex. 4.0 at 8.

- **High Rates of Default on Customer Deferred Payment Arrangements (“DPAs”).** In March of 2023, 24% of residential Peoples Gas customer DPAs failed. In that same month, 26% of North Shore residential customer DPAs failed. AG Ex. 4.0 at 9.

- **High energy burdens.** For Peoples Gas, the 131,644 residential customers carrying a past due balance owe an average of $792 each. For a family of three living at the poverty line, this past due balance would make up nearly 40% of their monthly income. AG Ex. 4.0 at 9. For North Shore, the 11,354 residential customers carrying a past due balance owe an average of $355 each. For a family of three living at the federal poverty line, this past due balance would make up nearly a fifth of their monthly income. Id. at 9.

- **A record-breaking rate increase request.** The unaffordability of Peoples Gas’ and North Shore’s rates will be significantly exacerbated by the pending request. In this case, Peoples Gas requests a $401.7 million increase—which is a 57% increase in delivery service rates. PGL/NS Ex. 24.01P, Sched. 1. North Shore is requesting a $16.5 million increase in revenues—which is a 17% increase. PGL/NS Ex. 24.01N, Sched. 1.01N.

- **High numbers of customers assessed late fees.** A total of 255,814 or 31% of Peoples Gas residential customers were assessed late payment fees or charges in March, highlighting the difficulties customers have staying current with PGL monthly bills. Id. at 9. A total of 27,483 or 18% of North Shore residential customers were assessed late payment fees or charges in March. AG Ex. 4.0 at 9.

- **Thousands of customers disconnected or at risk of disconnection.** From the period of April to November 2022, PGL issued 263,821 disconnection notices and executed 15,410 disconnections. These included 4,642 disconnection notices and 64 disconnections among low-income customers. PIO Ex. 3.0 at 14.

- **Disproportionate impact on PGL communities of color.** Within PGL’s service territory, even among zip codes with comparable median incomes, the rates of disconnection notices and disconnections are higher among zip codes that are...
most represented by a racial minority and rates of reconnection are lower among these same zip codes. PIO Ex. 3.0 at 20.

- **High flat, monthly customer charges.** Both AG witness Larkin-Connelly and COFI-LAC witness Colton agree that the Companies’ disproportionate reliance on the fixed charge has a disparate impact on low-usage customers, who are more likely to be lower-income customers. COFI-LAC Ex. 1.0 (CORR) at 103, 105, and 106; AG Ex. 4.0 at 14-15.

- **PGL bills consistently highest in the State.** Having examined the Commission’s annual “Comparison of Gas Sales Statistics” reported each year from 2013 through 2021 (the last year data was available), COFI/LAC witness Colton observed that Peoples Gas bills have consistently been higher than average gas bills for the State of Illinois as a whole. Mr. Colton noted a similar trend in North Shore rates. COFI-LAC Ex. 1.0 (CORR) at 8, 9.

  COFI/LAC also point out that the need for a robust, whole-bill low-income discount rate is highlighted by the fact that Illinois’ energy assistance programs, LIHEAP and PIPP, are budget-constrained and insufficiently funded. LIHEAP and PIPP can only protect low-income customers if they have adequate resources to truly reduce high energy burdens to make bills affordable, and if eligible customers participate in the programs. However, the Illinois Department of Commerce and Economic Opportunity (“DCEO”) – the agency that oversees the delivery of PIPP and LIHEAP within the state – reports that its program only reaches 21% of the eligible Illinois population (i.e., those whose income falls at or below 200% FPL). COFI/LAC Ex. 1.0 (CORR) at 23.

  Mr. Colton testified that DCEO has reported a significant increase in LIHEAP applications since the beginning of the October, 2023 program year—as high as a 33% increase as of January 2023. The agency reports that its overall energy assistance budget will drop from $404 million in fiscal year 2023 to $239 million in fiscal year 2024, which begins this fall. DCEO has reported that the average LIHEAP benefit for the coming 2024 fiscal year will decrease by nearly $300, from $1,010 to $725. Id. at 23. COFI/LAC note that DCEO also made the decision to shut down the PIPP program to new enrollees for the 2023 fiscal year due to budget constraints. And DCEO has confirmed at its quarterly Policy Advisory Committee meeting of April 27, 2023 that it will again not accept new PIPP enrollees for the 2024 fiscal year. Id. at 24.

  COFI/LAC assert that this shows the existing energy assistance programs are insufficient and underfunded, making it very difficult to address the Companies’ rate unaffordability. This underscores the need for COFI/LAC’s LIDR.

**COFI/LAC’s Proposal**

COFI/LAC explain that under their proposal, customers eligible for the LIDR would be customers with household incomes up to 300% FPL, including customers at or below 200% FPL, who are income-eligible for LIHEAP, and include those who do not currently participate in the program. The program will consist of a five-tier LIDR applied to the whole bill, not just the customer charge, with the discount percentage levels recommended by COFI/LAC witness Colton. Using a five-tiered structure, those tiers and discounts are:
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<thead>
<tr>
<th>Tier and income level</th>
<th>Peoples Gas</th>
<th>North Shore Gas</th>
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<tbody>
<tr>
<td>Tier 1: 0% to 50% FPL</td>
<td>83%</td>
<td>79%</td>
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<tr>
<td>Tier 2: 51% to 100% FPL</td>
<td>68%</td>
<td>68%</td>
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<tr>
<td>Tier 3: 101% to 150% FPL</td>
<td>45%</td>
<td>36%</td>
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<tr>
<td>Tier 4: 151% to 200% FPL</td>
<td>20%</td>
<td>12%</td>
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<tr>
<td>Tier 5: 201% to 300% FPL</td>
<td>5%</td>
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COFI/LAC further explain that their program allows eligibility for the LIDR to be based on a customer’s self-certifying income, where their household income is between 200% and 300% FPL. It also allows those who qualify for LIHEAP to participate regardless of whether they are participants in the program.

Individuals can apply for the discount through community action agencies or an income self-certification process, and the application process could be managed by a partnership between the Companies and Community Action Agencies, consistent with Nicor Gas Company’s comments to the Commission, which were included in the Low-Income Report.

COFI/LAC acknowledge that the LIDR will result in a revenue shortfall, requiring a plan for revenue recovery. COFI/LAC, Staff, PIO, and the Companies propose recovering these costs through a rider, disagreeing only on the structure of this rider. COFI/LAC propose a flat monthly charge to commercial and industrial customers, and a monthly volumetric charge to all residential customers of $.0932/therm for Peoples Gas and $.0225/therm for North Shore. The other parties propose a fixed monthly charge for all customers, meaning COFI/LAC only disagree with the method of cost recovery applied to residential customers. See AG Ex. 8.00 at 23.

It is COFI/LAC’s view that a proposal to recover LIDR costs from residential customers via a per therm charge is more consistent with Illinois’ clean energy goals because it is usage-based. They posit that high fixed costs disassociated from usage will tend to mute the effect of price signals. This risks limiting an important source of the Companies’ customers’ inclination to lower their energy usage.

Finally, COFI/LAC note that the LIDR ensures that the discounts applied specifically target a goal of 3% energy burden, and in a way that ensures that customers with the lowest incomes receive the largest discounts.

**Response to the Companies’ and Staff’s Proposal**

COFI/LAC state that both the Companies and Staff revised their LIDR proposals each time they filed testimony, with no revisions to incorporate any assessment of energy burden or bill affordability impacts. They add that the Companies simply adopted Staff’s revised proposal in its surrebuttal testimony, with no explanation as to how the shift in approach would affect these issues. NS-PGL Ex. 31.0 at 3. COFI/LAC note that neither Staff nor the Companies performed any analysis of the Companies’ customers’ energy burden at current rates, proposed rates, or under Staff’s revised customer charge low-income discount. In short, COFI/LAC state that neither the Companies nor Staff made any kind of assessment of whether their customer-charge-only discount would actually improve affordability for NS’ and PGL’s customers to an affordable level.
COFI/LAC assert that as Mr. Colton explained in his rebuttal testimony, the purpose of offering a low-income discount is not simply to provide "some" dollar amount to low-income customers. It is their position that the revised Staff proposal not only fails to supply sufficient discounts to those with the least income to achieve a 3% energy burden, it inefficiently applies the discount, with tiers that are too broad to precisely and efficiently address unaffordability.

COFI/LAC point out that Staff has proposed the same discount rate in all three pending gas rate cases, including Nicor’s (Docket No. 23-0066) and Ameren’s (Docket No. 23-0067) cases. This uniformity is unnecessary according to COFI/LAC. They assert that to the extent that Staff is seeking consistency in the LIDR across the state, no such recommendation was made in the Commission’s Low-Income Report. Additionally, the Companies specifically objected to such a policy and their witness, Mr. Barron, explained in his rebuttal testimony why a one-size fits all approach to a low-income discount rate is ill-advised. NS-PGL Ex. 20.0 at 17. COFI/LAC, however, states that on surrebuttal, Mr. Barron changed his position and accepted Staff’s revised proposal.

Response to the AG’s Recommendations and PIOs’ Proposal

COFI/LAC assert that other proposals, while better than Staff’s and the Companies’ proposal, do not achieve true affordability either. COFI/LAC identify several flaws in PIOs’ proposal. PIO witness Schott bases his tiers on increments of SMI rather than on increments of FPL (as the COFI/LAC proposals uses). COFI/LAC point out that while the federal LIHEAP statute allows for the use of SMI as a measurement of maximum income eligibility for LIHEAP to be set up to 60% of SMI (the maximum income eligibility recommended by Mr. Schott), there are additional complexities inherent in using SMI versus FPL. COFI/LAC remind the Commission that DCEO’s LIHEAP matrix divides benefit amounts in the precise FPL tiers used in Mr. Colton’s first four tiers, making determination of which discount a qualified customer should be assigned significantly easier for both a community action agency and even the company. See COFI-LAC Ex. 2.1.

Beyond this, COFI/LAC argue there are two aspects of Mr. Schott’s testimony that include the same flaws as the Staff/Companies’ revised approach. First, a two-tiered discount does not adequately disaggregate low-income customers when the objective is to achieve a gas bill as an affordable percentage of income. In Illinois, for example, in Federal Fiscal Year 2023, 60% SMI for a three-person household is $56,789, while 30% SMI for a three-person household would be $28,394. Using an undiscounted PGL bill of $1,472 simply for purposes of illustration, the PGL burden at the top of Mr. Schott’s Tier 2 would be 2.6% (below that burden deemed to be affordable) while the PGL burden at the bottom of the same income range would be 5.2%, nearly two times as high as the burden deemed to be affordable. COFI-LAC Ex. 2.0 at 40. Despite that difference, both such customers would receive the same discount under Mr. Schott’s proposal. Mr. Colton explained that if the objective is to achieve an affordable burden, that spread between the “top” and “bottom” is too great. Id.

Second, COFI/LAC note that Mr. Schott’s discount fails to include a needed fifth discounted tier (201% to 300%) to ensure customers who struggle each month to afford gas bills—but just miss qualifying for LIHEAP or PIPP—receive a modest discount. As
COFI/LAC witness Colton observed, incorporating a fifth tier recognizes the fragility of income at that income range. *Id.* at 40-41.

Finally, COFI/LAC note that AG witness Larkin-Connelly supports a LIDR with a modified version of the five tier criteria and the specific total bill discounts for each tier like COFI/LAC have proposed but with the discounts for each tier matching the discounts COFI/LAC proposed in the Nicor Gas case (Docket No. 23-0066). AG Ex. 8.0 at 48-49. COFI/LAC agree with all but the reduction in the actual discounts applied to the five tiers that would accompany a matching of the Nicor Gas proposal. They argue that Mr. Larkin-Connelly’s own analysis shows that the difference in his proposal versus the COFI/LAC proposal amounts to an average reduction in the PGL program cost savings, per customer, of $10.20 per year or 85 cents per month, with no assessment of the impact on affordability for those financially struggling customers receiving the smaller discounts. For NS customers, the average annual per customer savings for the cost of the LIDR program is $2.47 per year or 21 cents per month. COFI/LAC contend those annual increases to the cost of the LIDR program do not justify leaving eligible financially struggling customers with a higher energy burden.

f. **PIOs’ Position**

PIO note that P.A. 102-0662 amended Section 9-241 of the Act. The amended provision requires the Commission study the appropriateness, design, and implementation of discounted utility rates for low-income residential customers (Low-Income Discount Rate Study). 220 ILCS 5/9-241. Section 9-241 further authorizes the Commission “to permit or require electric and natural gas utilities to file a tariff establishing low-income discount rates” upon completion of its study. *Id.* PIO further note that the Commission completed a Low-Income Discount Rate Study on December 15, 2022 and the Commission directed Illinois’ large electric and gas utilities, including Peoples Gas, to file low-income discount rate tariffs with their next rate design filing. Minutes of the Commission, December 15, 2022 Regular Open Meeting at 25.

PIO state that Peoples Gas proposed a low-income discount rate tariff in its direct testimony. Subsequently, PIO, COFI/LAC, Staff, and the AG submitted counterproposals. PIO argue that the fundamental difference between the proposals is that PIO, COFI/LAC, and the AG’s proposals are designed to ensure all gas bills are affordable for Peoples Gas’ customers, whereas Staff’s and Peoples Gas’ proposal is not. Importantly, PIO point out that whereas the PIO, COFI/LAC, and AG’s proposals would apply a discount to a customer’s total bill, Staff’s and Peoples Gas’ proposal would apply a discount only to PGL’s customer charge. PIO maintain that PGL’s low-income customers struggle to pay their bills under *existing* rates, and Peoples Gas’ proposed rate increase—coupled with the impacts of electrification—will make it even tougher for low-income customers to do so in the future (even if the Commission were to adopt PIOs’ recommended disallowances and reduced customer charge).

PIO state that Peoples Gas’ low-income customers therefore require a robust discount to make their gas bills affordable. For that reason, PIO request that the Commission adopt PIOs’ proposed low-income discount rate, or in the alternative, COFI/LAC’s or the AG’s proposals. PIO argues PGL’s and Staff’s proposal is inadequate and therefore the Commission should reject it.
**PIOs’ Proposal**

PIO witness Justin Schott proposed a two-tier discount program for PGL, based on state median income ("SMI"). Under PIOs’ proposal, customers whose incomes are:

1. Up to 30% SMI would receive a discount of 75% of their total bill; and
2. From 30% SMI–60% SMI would receive a discount of 25% of their total bill.

PIO Ex. 3.0 at 27.

**Response to Peoples Gas’ and Staff’s Proposal**

PIO note that Peoples Gas and Staff agreed to their low-income discount rate after intervenor rebuttal testimony and thus PIO did not have an opportunity to comment on this proposal. However, PIOs’ witnesses commented extensively on the limited ability of delivery-only bill reductions to achieve affordability and those comments are applicable to the parties’ new proposal. PIO witness Schott presented evidence showing that “it is not possible to achieve an affordable gas burden for the lowest income customers by discounting only the delivery charges, which total $44.76 per month or $537 annually.” PIO Ex. 6.0 at 11. Mr. Schott shows that even with a 100% credit of the delivery charges, a discount that would be more generous than the one proposed by the Company and Staff, that households below 100% of the FPL would still face a 9.9% gas burden. *Id.* at 11. Meanwhile, PIOs’ proposal provides significant certainty that customers' bills remain around 3.5% of their total energy burden by discounting the entire bill. *Id.* at 11.

Mr. Schott explained that a household is “energy insecure” if it pays more than 3% of its gross household income on its gas bills. PIO Ex. 6.0 at 2. PIO note that Peoples Gas has a high prevalence of energy insecure customers in its service territory with over 80% of its customers having incomes below 60% of SMI. PIO Ex. 3.0 at 4-5. Energy insecurity disproportionately impacts low-income households, Black and Hispanic households, and households with children. *Id.* at 12. PIO elaborate that when energy insecure individuals are unable to pay their bills, they risk disconnection, which has a series of negative additional effects.

PIO observe that Peoples Gas witness Baron criticizes the discount rate proposals which apply to total bill. He states that such a rate would be inconsistent with the Low-Income Discount Rate Study which states that discount rates are applicable only to delivery service charges. NS-PGL Ex. 31.0 at 10. PIO take issue with this claim and maintain that the Commission should reject this argument. It is PIOs’ position that the Commission has the authority to adopt PIOs’ low-income discount rate pursuant to Section 9-241. While the Commission’s Low-Income Report concludes discounts “are applicable only to the delivery service charges”, PIO assert that nothing in Section 9-241 limits the Commission’s discretion to adopt flat rate discounts or discounts that apply only to delivery charges. Moreover, PIO, COFI/LAC, and the AG have shown in this proceeding that a discount that applies only to delivery service charges—like Peoples Gas’ and Staff’s proposal—would not ensure affordable gas bills for Peoples Gas’ low-income customers.
PIO assert that Peoples Gas’ and Staff’s proposal also leaves open the possibility of dramatic increases in price caused by variable supply prices. In a situation where gas supply charges spike by 50%, customers earning less than 30% of SMI would only experience a 12.5% increase in their bills under PIOs’ proposal. Id. at 12. However, under Peoples Gas’ and Staff’s proposal, which only applies to delivery charges, none of that new 50% increase in the bill would be mitigated. PIO emphasize that a discount rate that applies only to delivery charges leaves customers highly vulnerable to price shocks in volumetric supply charges. Id. at 12. Thus, PIO assert that Peoples Gas’ and Staff’s proposal would still place the lowest-income customers at risk of disconnection and the negative knock-on effects caused by this disruption in service.

PIO maintain that it is particularly important the Commission adopt an effective and comprehensive low-income discount rate, and not Peoples Gas’ inadequate proposal, because the assistance options the Company currently offers to its customers are not robust. See COFI/LAC Ex. 1.0 at 23-24 (describing the limitations of LIHEAP and PIPP programs). EDF witness Taylor, a Peoples Gas customer, described her experience applying for assistance from Peoples Gas for relief from bills that were over $1,000 in winter months—PGL informed Ms. Taylor she was not qualified for assistance, and did not offer any other support. EDF Ex. 1.0 at 3. PIO point to her testimony in which she states: “In all of the interactions I have had with Peoples Gas representatives, I was never directed to bill payment assistance or energy efficiency program resources. It would seem to me that helping people means making sure they are aware of all of the ways they can help mitigate the burden of ever increasing energy bills.” EDF Ex. 1.0 at 6. PIO also point to EDF witness Watson, another Peoples Gas customer, who echoed a similar concern about the assistance options Peoples Gas makes available to its customers, stating: “assistance programs don’t always work in a way that is helpful, despite seeming on the surface that they are moving the needle. Utilities get you in a cycle where the threat of disconnection is always looming – and in many cases give you a handful of days to pay huge bills – but any assistance programs have cycles that make them unavailable for weeks or months.” EDF Ex. 2.0 at 11. PIO state that its robust discount rate, in contrast, would be readily available to the PGL’s customers, and would offer relief specifically designed to help customers achieve affordability.

g. Commission Analysis and Conclusion

The evidence in the record shows that Peoples Gas’ and North Shore Gas’ current and proposed rates are unaffordable for substantial numbers of financially struggling customers within the Companies’ respective service territories. Staff proposes a three-tiered discount applied only to the customer charge and endorsed by the Companies in their surrebuttal testimony. LAC/COFI propose a five-tier program design based on a calculation relative to each customer’s total monthly bill.

The reigning measure of energy affordability aims for maximum 6% of income burden for gas (3%) and electric service (3%). See 305 ILCS 20/18(c)(2) (Illinois PIPP); see also LAC/COFI Ex. 1.0 at 14-15. The record evidence demonstrates that a significant portion of NS-PGL customers (i) have energy burdens well above the 3%-of-household income level, and (ii) are in need of a level of assistance well above what Staff offers. The LAC/COFI LIDR assessed the Companies’ rates, the income of the Companies’ customers in both service territories and developed discount rate levels for each
Company specifically designed to ensure that the Companies’ customers pay no more than 3% of their monthly income for gas utility service. The record shows the LAC/COFI LIDR program is the only one that included a specific assessment of the affordability of the Companies’ rates.

For all these reasons, the Commission approves the LAC/COFI low-income discount proposal. Specifically, under the LAC/COFI proposal, the Companies shall provide a targeted, five-tier discount applied to the customer’s whole bill. The Commission’s study report “tentatively” recommended that low-income programs should apply to delivery services only, pending specific proposals in a formalized proceeding. See ICC, Low-Income Discount Rate Study Report to the Illinois General Assembly, at 8-9, 62-63 (Dec. 15, 2022). The record evidence on the total bill discount presented by parties supports the Commission’s decision to alter that tentative determination and approve LAC/COFI’s proposed full bill discount. The Commission recognizes applying the discount to the entire bill will increase the amount to be paid by non-eligible customers, but also notes the potential utility system benefits associated with this program and encourages the Company to prioritize energy efficiency programming to reduce bills overall.

Under the structure adopted, eligibility shall be determined by household income as a percentage of the Federal Poverty Level (“FPL”). The Tiers consist of 0%-50% of FPL for Tier 1, 50%-100% of FPL for Tier 2, 100%-150% of FPL for Tier 3, 150%-200% of FPL for Tier 4, and 200%-300% of FPL for Tier 5. Eligibility for Tiers 1 through 4 can be reported by the community action agencies that serve LIHEAP customers. The discounted amounts for eligible Peoples Gas customers are Tier 1: 83%; Tier 2: 68%; Tier 3: 45%; Tier 4: 20% and Tier 5: 5%. The discounted amounts for eligible North Shore customers are Tier 1: 79%; Tier 2: 60%; Tier 3: 36%; Tier 4: 12% and Tier 5: 5%. Tier 5 can be self-reported by the customer.

Staff also recommends that the Companies develop a rate design proposal that included at least one low-income rate class at the time of the next general rate case. See NS-PGL Ex. 28.2. The Commission agrees with the Companies that Staff’s rate design can be implemented no sooner than a general rate proceeding filed six months after the first report filed with the first annual reconciliation of Rider LIDA. The Commission finds the current circumstances premature to give direction on this issue without the benefit of implementation data. Staff’s proposal is not adopted. The Commission finds that the lost revenue resulting from the LIDR program will be recovered from all customers. The initial effective period will be from October 1, 2024 through March 31, 2025. Thereafter, the LIDR will be effective April 1 through March 31. The adjustment to non-eligible customers’ bills will be displayed as a separate line item labeled as “Rider LIDAR.” The credit to eligible customers’ bills will be displayed as a separate line item labeled as “Low Income Discount Credit.” No later than June 30 of each year, the Companies will file petitions to reconcile the revenues collected during the effective period with the actual total discount credits applied.

The Companies will be required to provide reports every 3 months after the date of this Order about the status of implementation efforts until the implementation of the program is complete. These status reports shall be filed as compliance filings in this docket. The Companies are ordered to implement the adopted discount rates as quickly
as possible, no later than October 1, 2024. This timeline should reduce the need for interim relief given implementation will occur prior to the 2024/2025 winter heating season. Accordingly, the Commission declines to adopt LAC/COFI’s interim Share the Warmth Fund increase. While the Commission adopts the LAC/COFI Rider LIDA proposal in this proceeding, the Commission directs Staff to work with the Companies and stakeholders to commence workshops no later than January 15, 2026 to further consider the questions raised in this docket and the Low-Income Report, including but not limited to:

1. should Rider LIDA, or another cost recovery mechanism, be limited to residential customers only;
2. should the LIDR program incorporate seasonal differences in costs to customers and enable the Companies to discount either the distribution charge or the whole bill depending on the maximum potential discount to eligible customers;
3. should additional low-income levels be added to the program;
4. should the Commission consider approving a uniform LIDR program across all regulated gas utilities in Illinois;
5. is customer self-reporting income sufficient; and
6. what other income reporting methods could be used in determining customer eligibility.

Staff shall present a report to the Commission 60 days after the workshops conclude synthesizing the workshops and any recommended steps the Commission or the Companies should take going forward.

While the Commission expects LIDR to increase affordability across eligible customers, the Commission also anticipates the Companies will realize system benefits associated with reduced collections and customer service-related costs. LAC/COFI Witness Roger Colton noted Peoples Gas and North Shore Gas agreed the LIDR mechanism will reduce the Companies’ revenue requirements. LAC/COFI Ex. 1.0 CORR at 100; LAC-COFI Ex. 2.0 at 27-28; PGL response to COFI 3.17; NS response to COFI 9 3.17. The LIDR should also reduce uncollectibles and related disconnections tied to arrearages. To capture these various savings that will benefit all customers, the Companies will need to track the LIDR’s utility system impacts. The Companies, Staff, and stakeholders shall use system savings information when evaluating and estimating the value LIDR provides for the Companies. The Commission intends for these system savings to be quantified and incorporated into Rider LIDA reconciliations to adjust the under-recovery amounts consistent with the Companies’ realized LIDR-related system benefits. For the system savings to be included in future Rider LIDA reconciliations, the Commission directs Peoples Gas and North Shore Gas to track the following information (to the extent possible):

1. the dollar amount of uncollectibles costs that have been reduced on an annual basis subsequent to the implementation of the LAC/COFI LIDR;
(2) the dollar amount of credit and collections costs, and any other Company costs that have been reduced on an annual basis subsequent to the implementation of the LAC/COFI LIDR;

(3) the aggregated Tier 1 (0%-50% FPL) and Tier 2 (51%-100% FPL) customer billing and arrearage data from the two years prior to LIDR implementation to assess how LIDR impacts the customer and utility system benefit analysis (prioritizing past data from only Tier 1 and Tier 2 now, but eventually tracking this information for all tiers as the discount program matures);

(4) how the Companies have marketed the availability of the LIDR to populations who might qualify for the discount;

(5) what improvements can be made in those marketing efforts to reach more eligible customers; and

(6) other information Staff identifies as needed for incorporating system savings into a Rider LIDA reconciliation.

The Companies shall present a report with the above information to the Commission within twelve months from the date the LIDR goes into effect and every year thereafter. The report shall clearly document the level of reduced uncollectibles, credit, and collections costs, and any other reduced Company costs attributable to the LIDR. After the initial report, Staff will review and make a recommendation to the Commission as to when such system savings should be included in the Rider LIDA reconciliation accounting.

The Companies shall have 60 days after the final Order is entered to develop a final estimated timeline to make the necessary changes to its system by the implementation deadline of October 1, 2024. The report must include, but shall not be limited to the following: 1) identification of specific system changes necessary to implement the LIDR program; 2) any logistical, IT, or system barriers to implementing the program; 3) how the system changes to accommodate the LIDR program are prioritized among other existing IT and/or system upgrades and changes; and 4) implementation timelines for each discount tier, if they vary. The Commission finds that implementing the program by October 1, 2024 is imperative to ensure that the Companies’ most financially vulnerable customers receive assistance as the 2024/2025 winter heating season begins.

3. Non-residential Rate Design

a. S.C. No. 2, General Service

(i) Companies’ Position

North Shore proposes maintaining the three meter classes for S.C. No. 2. NS Ex. 7.0 REV at 12. Based on the ECOSS, North Shore proposes recovering 100% of customer-related costs through the customer charge for all meter classes. Id. at 12–13. In its Final Order in the Companies’ 2015 Rate Case, the Commission agreed that in the interest of gradualism, a portion of non-storage related demand costs could be recovered through the customer charges. Id. at 13. Therefore, the customer charge will recover 20% of non-storage demand related costs for Meter Classes 1 and 2 and 10% for Meter Class 3. Id. This proposal will recover only 38.5% of the revenue requirement for S.C.
No. 2 through fixed customer charges. *Id.* This will result in proposed customer charges of $1.08255, $2.70133, and $5.26828 per day for Meter Classes 1, 2 and 3 sales and transportation customers, respectively. *Id.* North Shore proposes recovering 70% and 30% of all remaining non-storage related fixed costs through the front block and end block, respectively. *Id.* Accordingly, the front block distribution charge will be set at 13.969 cents per therm and the end block distribution charge will be set at 11.960 cents per therm. *Id.* Storage-related costs will be recovered under Rider SSC.

North Shore’s proposals for S.C. No. 2 will affect the calculation of adjustments under Rider VBA. The S.C. No. 2 RCR will be set based on the distribution rates approved in this proceeding.

Peoples Gas proposes maintaining the three-meter classes for S.C. No. 2. PGL Ex. 7.0 REV at 13. Based on the ECOSS, Peoples Gas proposes recovering 100% of customer-related costs through the customer charge for all meter classes. *Id.* In its Final Order in the Companies’ 2015 Rate Case, the Commission agreed that in the interest of gradualism, a portion of non-storage related demand costs could be recovered through the customer charges. *Id.* Therefore, the customer charge will recover 16% of non-storage demand related costs for Meter Class 1, 20% for Meter Class 2 and 0% for Meter Class 3. NS-PGL Ex. 17.0 REV at 22. This proposal will recover only 30% of the revenue requirement for S.C. No. 2 through fixed customer charges. PGL Ex. 7.0 REV at 14. This will result in proposed customer charges of $1.76989, $5.60090, and $12.17670 per day for Meter Classes 1, 2 and 3 sales and transportation customers, respectively. *Id.* Peoples Gas proposes recovering 70% and 30% of all remaining non-storage related fixed costs through the front block and end block, respectively. *Id.* Accordingly, the front block distribution charge will be set at 28.767 cents per therm and the end block distribution charge will be set at 21.844 cents per therm. *Id.* Storage-related costs will be recovered under Rider SSC.

Peoples Gas’ proposals for S.C. No. 2 will affect the calculation of adjustments under Rider VBA. The S.C. No. 2 RCR will be set based on the distribution rates approved in this proceeding.

The Companies note that BOMA and the City challenge PGL’s rate design for S.C. No. 2 customers. BOMA claims that PGL’s requested rate increase is dramatic. BOMA IB at 11. The City challenges the fixed charge, asserting that PGL’s non-residential rate design “suffers from many of the same defects” as its residential rate design. COC IB at 70–73. For the reasons stated above, the Companies assert that both of these claims should be rejected and PGL’s proposal should be accepted.

(ii) Staff’s Position

According to Staff, North Shore proposed to recover 100% of its customer-related costs through the customer charge for each of the three-meter classes and proposes increases for all components within S.C. No. 2. Staff Ex. 5.0 at 18. Previously, the Commission agreed that a portion of non-storage related demand costs could be recovered through the customer charges. *Id.* citing NSG/PGL 2015 Order at 176. This exception results in 20% of non-storage related demand costs for Meter Classes 1 and 2, and 10% of non-storage related demand costs for Meter Class 3, being recovered through the customer charge. Staff Ex. 5.0 at 18. This calculated to 38.5% of the S.C.
No. 2 revenue requirement being recovered through the customer charges. *Id.* North Shore proposed to recover 70% of the remaining non-storage related fixed costs through the front block distribution charge and the remaining 30% through the end block. *Id.* The daily customer charge would increase from 87.604¢ ($26.65 monthly) to $1.08255 per day ($32.93 monthly) for Meter Class 1. *Id.* at 18-19. An increase of 20.651¢ daily or $6.28 monthly, which is an increase of 23.6%. The daily customer charge would increase from $2.31462 ($70.40 monthly) to $2.70133 per day ($82.17 monthly) for Meter Class 2. *Id.* at 19. An increase of 38.671¢ daily or $11.76 monthly, which is an increase of 16.7%. The daily customer charge would increase from $5.09322 ($154.92 monthly) to $5.26828 per day ($160.24 monthly) for Meter Class 3. *Id.* An increase of 17.506¢ daily or $5.32 monthly, which is a 3.4% increase. Staff Ex. 5.0 at 19.

The front block distribution charge would increase from 10.007¢ to 13.969¢ per therm, or by 3.962¢, which is a 39.6% increase. The end block distribution charge would increase from 8.974¢ to 11.960¢ per therm, or by 2.986¢, which is a 33.3% increase. *Id.*

Staff witness Harden recommends approval of Peoples Gas’ proposal for customer and distribution charges for general services sales and transportation customers be approved as it is based on the ECOSS and collects the class revenue requirement. *Id.*

Peoples Gas proposed to recover 100% of its customer-related costs through the customer charge for each of the three meter classes and proposes increases for all components within S.C. No. 2. Staff Ex. 5.0 at 29. The Commission agreed that a portion of non-storage related demand costs could be recovered through the customer charges. *Id.* citing NSG/PGL 2015 Order at 176. This resulted in 30% of non-storage related demand costs for Meter Classes 1 and 2, and 20% of non-storage related demand costs for Meter Class 3, being recovered through the customer charge. Staff Ex. 5.0 at 29. This calculated to 30% of the S.C. No. 2 revenue requirement being recovered through the customer charges. Peoples Gas proposed to recover 70% of the remaining non-storage related fixed costs through the front block distribution charge and 30% through the end block. *Id.* at 29-30.

The daily customer charge would increase from $1.16219 ($35.35 monthly) to $1.76989 per day ($53.83 monthly) for Meter Class 1. An increase of 60.770¢ daily or $18.48 monthly, which is 52.3%. The daily customer charge would increase from $4.10466 ($124.85 monthly) to $5.60090 per day ($170.36 monthly) for Meter Class 2. An increase of $1.49624 daily or $45.51 monthly, which is 36.5%. The daily customer charge would increase from $11.37205 ($345.90 monthly) to $12.17670 per day ($370.37 monthly) for Meter Class 3. An increase of 80.465¢ daily or $24.47 monthly, which is 7.1%. *Id.* at 30. The front block distribution charge would increase from 16.289¢ to 28.767¢ per therm, or by 12.478¢, which is 76.6%. The end block distribution charge would increase from 9.577¢ to 21.844¢ per therm, or by 12.267¢, which is 128.1%. Both of the distribution charges increase about 12¢. *Id.* at 29-30.

Staff witness Harden recommends approval of Peoples Gas’ proposal for customer and distribution charges for general services sales and transportation customers be approved as it is based on the ECOSS and collects the class revenue requirement. *Id.* at 30-31.
(iii) City’s Position

It is the City’s position that PGL’s rate design for S.C.2 and S.C.4 customers suffers from many of the same defects found in the rate design for residential customers. PGL intends to significantly increase its fixed customer charge for all users except for S.C.2, Meter Class 3.

The City claims that PGL’s rate designs for S.C.2 and S.C.4 are flawed and should be rejected for the same reasons that its rate design for S.C.1 should be rejected—it is based on an ECOSS that PGL has directed to classify many demand-related costs as “customer costs.” According to the City, PGL’s ECOSS shows that customers in S.C.2 and S.C.4 use service lines, meters, and regulators that have a range of costs, which vary with the level of demand. The City continues that, despite the demand-based variation in costs, PGL totals all costs in its accounting ledger’s categories for service lines, meters, and regulators as “customer costs” and that all customers in their assigned service sub-classification are required to share those “customer costs” equally. The City believes that, instead, PGL should be required to include in the customer cost classification only those costs for the basic level of service within that service classification and use only that basic customer level cost as the fixed customer charge. Then, all remaining costs should be classified as demand costs and collected through volumetric rates. COC Ex. 2.0 at 46-47.

According to the City, a proper rate design is one that avoids a regressive impact on lower commercial users, increases the incentive for efficient use and conservation of gas, and minimizes intra-class subsidization of higher users and that these objectives are just as, if not more important for gas customers in the commercial sector, as they are for small residential customers. The City takes the position that all of the commercial users in S.C.2 and S.C.4, including the City as a utility customer and as the sole local government policy maker within PGL’s service territory, will benefit from price signals that achieve the rate design policy set forth by the Commission in its 2015 Order. See 2015 Order at 176.

The City takes the position that Staff’s support for PGL’s S.C.2 and S.C.4 rate designs is as deficient as Staff’s support for PGL’s residential rate design. The City notes that, as with its analysis of residential rates, Staff has not had access to PGL’s proprietary ECOSS system nor has Staff analyzed the extent to which PGL’s calculation of “customer costs” includes demand-related costs. It is the City’s view that Staff also does not consider that, as a result of demand-inflated customer costs, PGL’s S.C.2 and S.C.4 rate designs are contrary to the Commission’s policy objectives established in the 2015 Order. See COC Ex. 4.0 at 20-23.

The Commission should, at a minimum, order PGL to develop new rate designs for S.C.2 and S.C.4 based on a new, transparently conducted ECOSS that: (a) classifies customer costs based on the basic customer method; and (b) briefly caps the customer charge at the current (pre-rate case). As a start, the City points to the basic customer method approach to the ECOSS and S.C.2 and S.C.4 rate design that PGL conducted based on Mr. Rábago’s instructions. See COC Table 2- City CIB at 43. The results of a Basic Customer Method ECOSS based on those oral instructions in the discovery
process of this proceeding are shown in “COC Table 6: Fixed Customer Charge for Commercial Users, Adjusted for Basic Customer Method Approach” City CIB at 72.

The City states that, based on years of PGL misclassifying its “customer costs,” correcting the problem of a fixed customer charge inflated by demand-related costs will be a significant change for S.C.2 and S.C.4 customers. Therefore, the City recommends and requests that the Commission direct PGL to prepare a schedule starting at the current customer charges and then decrease the customer charge in equal increments over a short period of time, no greater than five years.

The City also requests that the declining block rates in S.C. No. 2 should be considered for elimination, once the basic customer method is used in an ECOSS. COC Ex. 2.0 at 47. For S.C.4, the Commission should consider adjusting the demand charge for S.C.4 so that it applies only to customer-specific demand-related costs only during non-coincident system peaks. COC Ex. 2.0 at 47.

In sum, the City urges that the Commission require PGL to restructure its ECOSS’s method for classifying “customer costs” in S.C.2 and S.C.4 and, thereby, develop S.C.2 and S.C.4 customer charges that are based on cost-causation principles, minimize intra-class discriminatory rates, incentivize energy efficiency and conservation, and support the State’s and the City’s decarbonization policies.

(iv) BOMA/Chicago

In many respects, PGL attempts to characterize its proposed rate increase as “business as usual,” arguing that its positions are based on longstanding practice or merely continuations of programs that have been previously addressed by the Commission. However, according to BOMA/Chicago, for PGL customers, including BOMA/Chicago’s members, PGL’s dramatic and sudden rate increases represent serious economic threats. In his direct testimony, BOMA/Chicago witness Pruitt noted that PGL’s proposed rates may impose Distribution Charge increases of 46.07% on BOMA/Chicago members. BOMA Ex. 2.0 at 10; BOMA Ex. 2.4. PGL did not dispute Mr. Pruitt’s calculations regarding projected rate increases—or respond to that testimony in any way. Nor did PGL even acknowledge the testimony of T.J. Brookover, on behalf of BOMA/Chicago, regarding the potential impacts of such a dramatic rate increase, in particular in light of the other economic challenges facing commercial customers like BOMA/Chicago members. BOMA/Chicago note that the Commission has previously held that “[i]t is a widely held ratemaking policy that rates should be designed to reflect cost causation, maintain gradualism, and avoid rate shock.” Cent. Ill. Light Co. d/b/a AmerenCILCO, Docket Nos. 09–0306 to 09–0311 (cons.), Order at 295 (Apr. 29, 2010) aff’d 2012 IL App (4th) 100962. Therefore, to help to limit the sudden, dramatic rate increases PGL proposes, the revised cost allocations proposed by BOMA/Chicago should be adopted by the Commission.

BOMA/Chicago argue PGL witness Egelhoff simply dismissed Mr. Pruitt’s direct testimony on the grounds that it does not “propose any adjustments to the Companies’ rate design,” but did not offer any substantive comments that testimony. NS-PGL Ex. 17.0 at 18.
In his direct testimony, BOMA/Chicago witness Brookover described BOMA/Chicago, its members, and the potential impacts of PGL’s proposed rates on BOMA/Chicago members and the broader economy of the City of Chicago. BOMA Ex. 1.0. Mr. Brookover explained that BOMA/Chicago is a trade association representing Chicago office buildings and its membership includes 244 office, institutional, and cultural buildings and 190 companies that provide building support services, representing roughly 80% of the rentable downtown Chicago office space. Id. Mr. Brookover further testified that approximately two thirds of BOMA/Chicago member buildings use natural gas and are customers of PGL. Id. at 4. For these buildings, natural gas costs are one of the largest categories of expenses. Id.

Mr. Brookover explained that a dramatic change in utility costs over a short period of time, such as the increase proposed by PGL for non-residential customers, can cause financial distress for BOMA/Chicago’s member buildings and directly impact the thousands of businesses they house. Id. at 5. Increased utility costs are typically passed down to tenants of Chicago office buildings, and most commercial leases in downtown Chicago contain provisions assigning a portion of the projected utility costs to tenants based on the square footage leased. Id. When utility costs rise beyond projections, tenants may be assessed additional charges to account for the shortfall. Id. If a building is not fully occupied, the utility costs that would normally be paid by the tenants of the vacant space are either borne by the building or recovered through additional charges to remaining tenants (above and beyond the direct cost of utility rate increases). Id. Because commercial leases in downtown Chicago are typically for terms of 5 to 15 years, Mr. Brookover noted that tenants facing rapid cost increases may seek to sublease their space or to reduce their number of employees in order to offset rising facility costs. Id.

Critically, PGL’s proposed rate increases would come on the heels of other serious challenges currently facing BOMA/Chicago members. Mr. Brookover testified that Chicago commercial properties are facing increased vacancies, decreased office occupancy, increased interest rates, and rising rates of other utilities. Id. at 6.

Citing to the most recent data from Colliers, International (“Colliers”), a real estate services and investment management company, Mr. Brookover explained that as of Q1 2023 the vacancy rate in downtown Chicago office buildings was a record 22.1% (up from a pre-pandemic vacancy rate of 12.9%). Id. Moreover, Mr. Brookover quoted Colliers’s projection that “there is no expectation that overall vacancy will decrease” in the Central Business District in the near term. Id. Colliers also reports (and BOMA/Chicago members are experiencing) record high levels of office sublease inventory in downtown Chicago. Id. As existing leases on these spaces expire it is expected that the vacancy rates in downtown Chicago will continue to rise. Id. at 6-7. Additionally, Mr. Brookover testified that many office tenants executed short-term extensions during the COVID-19 pandemic, and as these expire the vacancy rate may further increase. Id. at 7.

Mr. Brookover noted that these issues are compounded by the drastic increase in work-from-home employment since the COVID-19 pandemic. Id. at 7-8. Mr. Brookover stated that employee occupancy in downtown Chicago office buildings has plateaued at an occupancy rate of between 40%-43% over the past year. Id. at 7-8.
An additional factor contributing to the financial difficulties faced by BOMA/Chicago members is higher interest rates. Id. Office building ownership and management is a capital intensive business, and rising rates may have significant impacts and may ultimately contribute to increased rents, higher vacancies, and lower building valuations. Id. Finally, Mr. Brookover pointed out that PGL rate increases will be compounded by ComEd’s proposed electric rate increase, currently pending in Docket No. 22-0487/23-0055 (cons.). Id. at 9.

In total, Mr. Brookover testified that increased vacancies and other economic challenges will and already are leading to reduced valuations for buildings in downtown Chicago. Id. at 7. Reduced building valuations will lead to reduced property tax revenues for the City, potentially requiring cuts to services or re-allocation of lost tax revenue to other taxpayers. Id. at 7, 11. Additionally, Mr. Brookover testified high vacancy rates and other economic issues have already led to reduced employment and contracting by BOMA/Chicago members for services such as building operations, engineering, cleaning, etc. Id. at 7. Mr. Brookover added that the rise in vacancy has correlated with a significant decline in downtown office building construction, to the detriment of the quality union jobs that the construction industry supports. Id. at 10.

Mr. Brookover further testified that rising vacancy and declining building values also lead to lower building transactions, and this in turn hinders capital projects, downtown revitalization, and tax revenues. Id. at 9. Mr. Brookover highlighted a downward trend in building transactions in downtown Chicago in recent years. In 2021, building transactions in the Central Business District were valued at $1.5 billion, down from a recent high of $6.4 billion in 2015. Id. at 10. The City of Chicago has acknowledged these issues, announcing a $500 million investment program for the LaSalle Street corridor in response to “significant office and retail vacancy rates exacerbated by the COVID-19 pandemic and its ongoing market trends.” Id. at 10.

BOMA/Chicago state PGL’s proposed rate increase will dramatically increase costs for its customers and disproportionately shift the burden of that rate increase onto non-residential customers such as BOMA/Chicago members. These severe changes will significantly impact the commercial real-estate industry that is already reeling from the lasting effects of the COVID-19 pandemic. PGL declined to respond – or even acknowledge in any way – the significant concerns raised by Mr. Brookover on behalf of a major PGL customer group and an important industry for the City of Chicago. As Mr. Brookover’s uncontested testimony shows, PGL’s proposed rate plan poses a significant risk of rate shock, and the Commission should take steps to ensure that cost increases are spread over a larger customer base to reduce these risks. See Ill.-Am. Water Co., Docket No. 22-0210, Order at 147 (Dec. 15, 2022) (holding that spreading the cost of capital improvement costs over a larger customer base would mitigate potential rate shock).

(v) Commission Analysis and Conclusion

Staff reviewed the proposals by the Companies and agrees with the charges for S.C. No. 2. The Commission, therefore, accepts North Shore’s proposal to maintain the three meter classes for S.C. No. 2, with 100% recovery of customer-related costs through the customer charge for all meter classes. The Commission finds that this proposal is
consistent with its Order in the 2015 Rate Case, which found that, in the interest of gradualism, a portion of non-storage related demand costs could be recovered through the customer charges. Accordingly, the customer charge will recover 20% of non-storage demand related costs for Meter Classes 1 and 2 and 10% for Meter Class 3; and the recovery of only 38.5% of the revenue requirement for S.C. No. 2 through fixed customer charges, resulting in proposed customer charges of $1.08255, $2.70133, and $5.2628 per day for Meter Classes 1, 2, and 3 sales and transportation customers, respectively. The Commission further agrees with North Shore recovering 70% and 30% of all remaining non-storage related fixed costs through the front block and end block. Lastly, the Commission approves the Companies’ proposal for storage-related costs to be recovered under Rider SSC, and to base the S.C. No. 2 RCR on the distribution rates approved in this proceeding.

The Commission also agrees with North Shore recovering 70% and 30% of all remaining non-storage related fixed costs through the front block and end block, respectively. Lastly, the Commission approves the Companies’ proposal for storage-related costs to be recovered under Rider SSC, and to base the S.C. No. 2 RCR on the distribution rates approved in this proceeding.

b. S.C. No. 4, Large Volume Demand Service

(i) Companies Position

For North Shore, the customer charge for S.C. No. 4 will be set at cost and will decrease to $10.34763 per day. NS Ex. 7.0 REV at 13. The demand charge will recover 70% of non-storage related demand costs and will increase to 82.433 cents per therm of billing demand. Id. at 13–14. The distribution charge, which will recover remaining non-storage related demand costs, will increase to 2.425 cents per therm. Id. at 14. Storage-related costs will be recovered under Rider SSC.

For Peoples Gas, the customer charge for S.C. No. 4 will be set at cost and will increase to $65.42912 per day. PGL Ex. 7.0 REV at 14. The demand charge will recover 55% of non-storage related demand costs and will increase to 1.61285 per therm of billing demand. Id. at 14. The distribution charge, which will recover remaining non-storage related demand costs, will increase to 8.747 cents per therm. Id. at 140. Storage-related costs will be recovered under Rider SSC.

The City challenges PGL’s design, claiming that it “suffers from many of the same defects” as its residential rate design. COC IB at 70–73. For the reasons stated above, NS and PGL argue the City’s claim should be rejected and PGL’s proposal accepted.
(ii) **Staff’s Position**

Staff states that North Shore proposed to set the customer charge at cost which will result in a decrease to the customer charge and increases to the demand charge and the distribution charge. Staff Ex. 5.0 at 20. The Company’s proposal recovers 70% of non-storage related demand costs in the demand charge with the remainder recovered from the distribution charge. Id. The daily customer charge would decrease from $11.57152 per day ($351.97 monthly) to $10.34763 per day ($314.74 monthly) or by $37.23, which is a 10.6% decrease. Id. at 21. The demand charge would increase from 68.708¢ per therm to 82.433¢ per therm, for an increase of 13.725¢ per therm, or 20.0%. Id. The distribution charge would increase from 2.058¢ per therm to 2.425¢ per therm, which is an increase of 3.67¢ per therm, or 17.8%. Id.

Staff recommends approving the proposal to decrease the customer charge and increase both the demand and distribution charges for the Large Volume Demand Service sales and transportation customers, as it is based on the ECOSS and recovers the revenue requirement. Id.

Staff states that Peoples Gas proposed an increase to the customer charge, the demand charge and the distribution charge for S.C. No. 4, Large Volume Demand Service customers. Staff Ex. 5.0 at 32. Company witness Egelhoff proposed to set the customer charge at cost and recover 55% of non-storage related demand costs in the demand charge, with the remainder recovered from the distribution charge. Id. The daily customer charge would increase from $30.18082 per day ($918.00 monthly) to $65.42912 per day ($1,990.14 monthly) or by $1,072.14, which is 116.8%. Id. The demand charge would increase from 87.835¢ per therm to $1.61285 per therm, for an increase of 73.450¢ per therm, or 83.6%. Id. The distribution charge would increase from 6.036¢ per therm to 8.747¢ per therm, which is an increase of 2.711¢ per therm, or 44.9%. Id.

Staff recommends approving Peoples Gas’ proposal to increase the customer charge, the demand and distribution charges for the Large Volume Demand Service sales and transportation customers, as it is based on the ECOSS and recovers the revenue requirement. Staff Ex. 5.0 at 32.

(iii) **City’s Position**

It is the City’s position that PGL’s rate design for S.C.4 customers suffers from many of the same defects found in the rate design for residential customers. The City claims that PGL’s rate designs for S.C.2 and S.C.4 are flawed and should be rejected for the same reasons that its rate design for S.C.1 should be rejected—it is based on an ECOSS that PGL has directed to classify many demand-related costs as “customer costs.”

According to the City, PGL’s ECOSS shows that customers in S.C.2 and S.C.4 use service lines, meters, and regulators that have a range of costs, which vary with the level of demand. The City continues that, despite the demand-based variation in costs, PGL totals all costs in its accounting ledger’s categories for service lines, meters, and regulators as “customer costs” and that all customers in their assigned service subclassification are required to share those “customer costs” equally. The City believes that, instead, PGL should be required to include in the customer cost classification only
those costs for the basic level of service within that service classification and use only that basic customer level cost as the fixed customer charge. Then, all remaining costs should be classified as demand costs and collected through volumetric rates. COC Ex. 2.0 at 46-47.

According to the City, a proper rate design is one that avoids a regressive impact on lower commercial users, increases the incentive for efficient use and conservation of gas, and minimizes intra-class subsidization of higher users and that these objectives are just as, if not more important for gas customers in the commercial sector, as they are for small residential customers. The City takes the position that all of the commercial users in S.C.2 and S.C.4, including the City as a utility customer and as the sole local government policy maker within PGL’s service territory, will benefit from price signals that achieve the rate design policy set forth by the Commission in its 2015 Order. See 2015 Order at 176.

The City takes the position that Staff’s support for PGL’s S.C.4 rate designs is as deficient as Staff’s support for PGL’s residential rate design. The City notes that, as with its analysis of residential rates, Staff has not had access to PGL’s proprietary ECOSS system nor has Staff analyzed the extent to which PGL’s calculation of “customer costs” includes demand-related costs. It is the City’s view that Staff also does not consider that, as a result of demand-inflated customer costs, PGL’s S.C.4 rate design is contrary to the Commission’s policy objectives established in the 2015 Order. See COC Ex. 4.0 at 21-23.

The Commission should, at a minimum, order PGL to develop new rate designs for S.C.2 and S.C.4 based on a new, transparently conducted ECOSS that: (a) classifies customer costs based on the basic customer method; and (b) briefly caps the customer charge at the current (pre-rate case). As a start, the City points to the basic customer method approach to the ECOSS and S.C.4 rate design that PGL conducted based on Mr. Rábago’s instructions. See COC Table 2-City CIB at 43.

The City states that, based on years of PGL misclassifying its “customer costs,” correcting the problem of a fixed customer charge inflated by demand-related costs will be a significant change for S.C.4 customers. Therefore, the City recommends and requests that the Commission direct PGL to prepare a schedule starting at the current customer charges and then decrease the customer charge in equal increments over a short period of time, no greater than five years.

The City also requests that for S.C.4, the Commission should also consider adjusting the demand charge for S.C.4 so that it applies only to customer-specific demand-related costs only during non-coincident system peaks. COC Ex. 2.0 at 47.

In sum, the City urges that the Commission require PGL to restructure its ECOSS’s method for classifying “customer costs” in S.C.4 and, thereby, S.C.4 customer charges that are based on cost-causation principles, minimize intra-class discriminatory rates, incentivize energy efficiency and conservation, and support the State’s and the City’s decarbonization policies.
(iv) **Commission Analysis and Conclusion**

Staff recommends approving the Companies’ proposal to decrease the customer charge and increase both the demand and distribution charges for the Large Volume Demand Service sales and transportation customers, as it is based on the ECOSS and recovers the revenue requirement. The Commission accepts North Shore’s proposal to set the customer charge for S.C. No. 4 at cost and to decrease to $10.34763 per day, with the demand charge recovering 70% of non-storage related demand costs and to increase to 82.433 cents per therm of billing demand. The Commission further accepts that the distribution charge, which will recover remaining non-storage related demand costs, with storage-related costs recovered under Rider SSC.

The Commission also accepts Peoples Gas’ proposal to set the customer charge for S.C. No. 4 at cost and to increase to $65.42912 per day, with the demand charge recovering 55% of non-storage related demand costs and to increase to 1.61285 cents per therm of billing demand. The Commission further accepts that the distribution charge, which will recover remaining non-storage related demand costs, with storage-related costs recovered under Rider SSC.

c. **S.C. No. 8 (PGL only)**

(i) **Companies’ Position**

Peoples Gas proposes setting S.C. No. 8 at cost. The monthly customer charge will decrease to $5.02028 per day and the distribution charge will increase to 23.886 cents per therm. Storage-related costs will be recovered under Rider SSC.

The City contests this rate design based on its challenges to the fixed charge. COC Ex. 2.0 at 45–46. For the reasons stated above, the City’s criticisms should be rejected and the Companies’ proposals accepted.

(ii) **Staff’s Position**

Peoples Gas proposed a decrease to the customer charge and an increase to the distribution charge which would set the S.C. No. 8 class at cost. *Id.* at 33. The daily customer charge would decrease from $7.69315 per day ($234.00 monthly) to $5.02028 per day ($152.70 monthly) or an $81.30 decrease, which is 34.7% lower. *Id.* The distribution charge would increase from 12.807¢ per therm to 23.886¢ per therm, an 11.079¢ increase, or 86.5%. *Id.*

Staff recommends that the Company’s proposal to decrease the customer charge and increase the distribution charge for the Compressed Natural Gas Service sales and transportation customers be approved, as Peoples Gas’ proposal sets the class at the cost to provide the service. *Id.* at 34.

(iii) **Commission Analysis and Conclusion**

The Commission agrees with Staff and accepts Peoples Gas’ proposal to set S.C. No. 8 at cost, with the monthly customer charge decreasing to $5.02028 per day and using the distribution charge in recovering the remainder of the cost to serve the class. Storage-related costs will be recovered under Rider SSC.
4. Main and Service Line Extensions – Rider 4 and Rider 5

a. Companies’ Position

The Companies state that longstanding statewide utility practice supports service and main line extension allowances for new customers. NS-PGL Ex. 17.0 REV at 19. The Commission has repeatedly endorsed this practice, including by approving the Companies’ respective Rider 4 (Main Extensions) and Rider 5 (Service Lines). Id. at 19. Allowing certain lengths of service lines and mains recognizes that expanding or adding to a utility system in the aggregate benefits all customers over time. Id.

PIO witness Cebulko disagreed, arguing that these allowances should be eliminated, because “subsidizing” gas line extensions is not in customers’ long-term interests, new customer additions may still lead to lower rates, and any prior rationales for the allowances are no longer valid. PIO Ex. 1.0 at 47. Mr. Cebulko’s challenge to these allowances arises out of his general grievance with the Companies’ revenue requirements. Id. at 45.

Mr. Cebulko’s recommendation to exclude these allowances is no small request according to the Companies. As Ms. Egelhoff explained, there is no provision in P.A. 102-0662 that directs natural gas utilities to eliminate the practice of providing these allowances. NS-PGL Ex. 17.0 REV at 19. Nor is there any merit to Mr. Cebulko’s contentions.

First, customers continue to benefit from the principle of sharing the fixed costs of the utility system. Id. at 20. The Companies’ current rate structure is based on cost-of-service principles and sharing fixed costs across a utility’s entire rate base. Id. at 20. That is not a subsidy. Id. at 20. Existing and new customers share the cost of upgrading and expanding the gas distribution system. Id. at 20.

Second, policy goals and potential for stranded costs due to electrification do not justify eliminating longstanding allowances in this proceeding. Id. at 21. Expanded energy efficiency investments by the state’s electric and gas utilities should continue to make energy consumption more efficient, reducing demand and usage. However, it is not clear when and how those effects will become apparent. Id. at 21. As Companies witness Graves explained in his rebuttal testimony (NS-PGL Ex. 22.0), those types of issues require detailed study and debate with input from all stakeholders, and a time-constrained rate case is not the appropriate forum to consider them. Id. at 21.

The Companies assert that to the extent that the Commission is inclined to consider abandoning allowances for main and service lines in favor of some other model for cost recovery, such a change in longstanding public utility policy should be conducted in a statewide review of energy transitions. Id. at 22.

b. PIOs’ Position

In addition to requiring a rigorous alternatives analysis for major pipeline replacement projects, PIO request that the Commission also control Peoples Gas’ capital spending going forward by directing the Company to modify its existing line extension allowances. PIO asserts that the Commission has the authority to direct this tariff modification based on the record. Line extension allowances encourage system growth by providing new gas customers a subsidy that covers all or a portion of the cost of
extending main and service lines to the customer. PIO state that Peoples Gas' line extension allowances therefore translate directly to main and service expenditures, and ultimately, higher rates for the Company’s ratepayers. PIO Ex. 1.0 at 44-47.

PIO maintain that line extension allowances were consistent with the state’s past policy objectives because those allowances made it easier for the utility to add new customers which had the effect of socializing the capital costs of connecting those customers to gas service. They state that this rationale is no longer valid—increasing electrification will make it even more difficult (and in many cases impossible) for the Company to recover the costs of its line extension allowance through incremental revenues, resulting in cost shifts between new and existing customers. Id. at 47.

PIO recommend the Commission direct the Company to eliminate its service line extension allowances, and open a rulemaking within a year of its Order in this proceeding to eliminate mandatory main extension allowances, rather than waiting until the Future of Gas proceeding as requested by Peoples Gas.

c. Commission Analysis and Conclusion

The Commission addresses the issue of line extension allowances in Section IV.B.5.v.

5. Terms and Conditions

a. Change from Monthly Service Charge to Daily Service Charge (PGL only)

(i) Companies’ Position

Peoples Gas is proposing to change from a monthly customer charge to a daily customer charge, which would make Peoples Gas’ customer charge design consistent with that of the other WEC utilities, including North Shore. Staff witness Harden supports this change, recognizing that it will more closely align the customer charge with the actual billing period and will not impact annual revenues. Staff Ex. 5.0 at 24.

No party contested this proposed change in direct testimony, but in rebuttal testimony, AG witness Larkin-Connolly stated that he opposed it, and urged rejection of the change for Peoples Gas and for North Shore to revert to a monthly customer charge. AG Ex. 8.0 at 17. Peoples Gas argues that his opposition was untimely and lacks support. The Commission approved the move to a daily calculation in North Shore’s last rate case—a docket in which the AG participated and did not object to the change. NS-PGL Ex. 28.0 at 11. Mr. Larkin-Connolly failed to recognize the efficiencies of the daily charge and did not present a compelling case for the Commission to reverse course from its decision in North Shore’s last rate case. Id. at 10. Peoples Gas opines that moving to a daily customer charge will simplify billing system administration and allow for common management and treatment of billing records. Id. The change will not affect a customer's annual fixed charges. Id. at 10-11. Instead of dividing the annual customer costs by 12, the annual costs will be divided by 365. PGL Ex. 7.0 REV at 10. Customers will be charged the daily rate times the number of days in each billing period. Id.

Mr. Larkin-Connolly alleged that PGL’s motivation for switching to a daily fixed charge is “to obfuscate” an increase in fixed charges. AG Ex. 8.0 at 18. Peoples Gas
asserts this accusation is simply untrue. NS-PGL Ex. 28.0 at 11. The customer bill will clearly indicate an amount of fixed charge and the calculation for it. Id. It will be identified as a fixed charge and calculated based on a fixed rate that is multiplied by the number of days in a billing period. Id. There will be no cause for confusion.

As a result of moving to a daily customer charge, Peoples Gas proposes various revisions to its tariff. Peoples Gas explains that the “Customer Charge” line item on current bills reflects the sum of seven rates. In addition to the service classification customer charge rate, the following six rates are included in the “Customer Charge” line: Energy Assistance Charge for the Supplemental Low-Income Energy Assistance Fund (LIAF), Renewable Energy Resources and Coal Technology Development Assistance Charge (RERC), Public Utility Assessment Charge (PUAC), Uncollectible Expense Adjustment (UEA), Special Purpose Charge (SPC), and Third-Party Transaction Fee Adjustment (TPTFA). PGL Ex. 7.0 REV at 18. Effective October 1, 2023, SPC will be set to zero per the tariff; however, a reconciliation will be filed on or before December 20, 2023, after which a reconciliation adjustment will be included on customer bills. Id. On the effective date of new base rates, TPTFA will be set to zero until a final reconciliation adjustment is filed per Rider TPTFA, Section A. Id. Changing the customer charges to daily rates will require these other six rates to change to daily rates as well.

Peoples Gas further explains that LIAF and RERC daily rates will be set by multiplying the monthly rates by 12 months and dividing by 365 days, rounded to five decimal places. Id. at 19. The daily rates for PUAC, UEA, SPC, and TPTFA will be calculated per the revised tariff pages shown in Ex. 7.1. Id. Under the Rider PUAC tariff and the Rider UEA tariff, Peoples Gas is proposing to revise the formulas to divide the allocated adjustments by the average of the forecasted number of billing periods in the respective effective period divided by the number of days in the same effective period. Id. For Rider SPC, Peoples Gas proposes converting the monthly charges to daily charges by simply multiplying the monthly charges as allocated by service classification by twelve months, then dividing by 365 days. Id.

As mentioned above, Peoples Gas proposes changing the “Customer Charge” line item on the bill to “Fixed Charge” to reflect the fact that more than the service classification customer charge is billed in this line item. PGL Ex. 7.0 REV at 20. The newly named “Fixed Charge” line item will display the sum of the daily rates of the customer charge, Rider UEA, Rider SPC, Rider TPTFA and Rider 1 (PUAC, LIAF, and RERC) multiplied by the number of days in the billing period. The Definition of Terms on the back of the bill will reflect the changes to this bill line item, too.

(ii) Staff’s Position

Peoples Gas proposed a general change to its rate design to change from a monthly customer charge to a daily customer charge so that Peoples Gas’ rate structure is consistent with North Shore as well as WEC’s Wisconsin and Michigan utilities that are in the WEC Energy Group. Staff Ex. 5.0 at 23. Company witness Egelhoff testified that the change will allow for administrative efficiencies that include simplifying the billing system administration, allowing for shared management and simplified treatment of the billing records. Id. She further stated that changing to a daily customer charge will have a net zero annual effect on customer bills. Id. Ms. Egelhoff used a daily rate in testimony
to allow for an “apples to apples” comparison. *Id.* The Company witness discussed the different components of the customer charge that will need to be changed to a daily rate if approved by the Commission. *Id.* at 23. The Company also proposed to change the line item on a customer’s bill from the description “Customer Charge” to “Fixed Charge” to reflect the multiple rates that are included in this line item on a customer’s bill. *Id.* at 24.

Staff does not oppose Peoples Gas’ proposal to change from a monthly customer charge to a daily rate as it should not have an impact on annual revenues. Staff Ex. 5.0 at 24. Staff explains that the customer bills will more closely align the customer charge with the actual billing period. *Id.* The customer’s monthly bill will reflect the number of days covered over the billing period, times a daily rate that will be listed in the tariff. *Id.*

Staff does not oppose the change in description on the customer’s monthly bill which encompasses other rates. *Id.* at 25. Additionally, Staff notes that the Commission approved North Shore’s proposal to change to a daily customer charge and to the term “Fixed Charge” in North Shore’s last rate case. *Id.*

(iii) **AG’s Position**

The AG requests the Commission adopt Mr. Larkin-Connolly’s recommendation and reject PGL’s proposal to use a daily fixed charge for its residential rate design. The Companies allege that the Commission should reject this proposal because it fails “to recognize the efficiencies of the daily charge,” that “will simplify billing system administration and allow for common management and treatment of billing records.” NS/PGL IB at 198. However, rather than creating more efficiencies, the AG’s analysis shows that the Companies’ proposal will add “arbitrary fluctuation to the monthly bill and make [PGL’s] fixed charges less comparable to other companies.” AG Ex. 8.00 at 18:329–334.

North Shore currently uses a daily fixed charge while PGL uses a monthly fixed charge. In reviewing PGL’s proposal to move to a daily fixed charge, Mr. Larkin-Connolly found that this switch would add “arbitrary fluctuation to the monthly bill and make Peoples [Gas]’ fixed charges less comparable to other companies.” AG Ex. 8.00 at 18. He testified that a daily fixed charge is arbitrary because PGL sends out bills once per month, meaning the frequency of the bill does not change based on the number of days in the month or in the particular bill. *Id.* Similarly, Mr. Larkin-Connolly stated that the customer-related costs in PGL’s ECOSS are based on billing and collections costs, which are calculated on a monthly basis. *Id.* at 18. He testified that a daily fixed charge will likely increase the line items on customers’ bills because it will require the daily fixed charge to be multiplied by the number of days in the month—rather than a single monthly fixed charge like currently appears on PGL’s bills. *Id.* at 18–19. As a result of these combined issues, the AG contends that PGL’s transition to a daily fixed charge would create arbitrary, unnecessary, and unjustified customer confusion and bill instability.

The AG iterates that the Commission has a duty to ensure “the application of rates is based on public understandability and acceptance of the reasonableness of the rate structure and level.” 220 ILCS 5/1-102(d)(ii). While the Companies claimed that the AG’s concerns about customer confusion were unfounded, they went on to discuss how this change would affect six different rates and their respective calculations. NS/PGL IB at
199–200. The AG asserts that the Companies have failed to demonstrate how these complex changes are preferable to the status quo from a customer-facing perspective. The AG reminds the Commission that it should not adopt such arbitrary and unjustified changes without justification, especially where it is shown to be detrimental to consumers. See, e.g., Citizens Util. Bd., 276 Ill. App. 3d at 737 (1st Dist. 1995).

For these reasons, the AG asks the Commission to reject PGL’s proposal to move from a daily fixed charge to a monthly fixed charge. In addition, and for the same reasons, the Commission should require North Shore to replace its daily charge to a monthly fixed charge, consistent with PGL and with the other major Illinois utilities. E.g., Ameren Illinois Company Gas Service, Sch. Ill. C. C. No. 2 at Sheet No. 11.001; Ameren Illinois Company Electric Service, Sch. Ill. C. C. No. 1 at Sheet No. 11.001; Commonwealth Edison Company, Sch. Ill. C. C. No. 10 at Sheet No. 60; Northern Illinois Gas Company, Sch. Ill. C. C. No. 16 – Gas at Sheet No. 10.

(iv) Commission Analysis and Conclusion

PGL requests to transition from a monthly fixed service charge to a daily fixed service charge. PGL indicated that the change would allow for administrative efficiencies that include simplifying the billing system administration, allowing for shared management and simplified treatment of the billing records. However, the AG indicated that PGL’s transition to a daily fixed charge would create arbitrary, unnecessary, and unjustified customer confusion and bill instability. The AG further noted this change will affect six different rates and their respective calculations on customer bills, and that PGL has not justified such complex changes from a customer-facing perspective. The Commission has a duty to ensure that the public understands the rates charged by utilities. See 220 ILCS 5/1-102(d)(ii). Adding additional complexity to customers’ bills, when PGL admits that these changes will not affect revenue, is unjustified. Accordingly, the Commission rejects PGL’s proposal and orders the Company to maintain its current practice applying a monthly fixed service charge to customers’ bills.

The Commission approved the move to a daily charge in the last North Shore rate case. In light of the concerns raised by the AG and the Commission’s conclusion to reject PGL’s proposal to move to a daily charge, the Commission orders North Shore to revert to a monthly charge.

C. Other

1. Rider UEA-GC – Uncollectible Expense Adjustment – Gas Cost

a. Companies’ Position

The Companies state that both North Shore and Peoples Gas propose revisions to Rider UEA-GC, Uncollectible Expense Adjustment – Gas Costs, to reflect the proposed Uncollectible Factors arising from data in this proceeding. NS Ex. 7.0 REV at 16; PGL Ex. 7.0 REV at 17. Those proposed Uncollectible Factors and their derivation are provided in NS Ex. 7.8 and PGL Ex. 7.8, with the proposed Uncollectible Factors being shown in column F. Id., NS Ex. 7.0 REV at 16; PGL Ex. 7.0 REV at 17. The allocation by rate class of the uncollectible amount that would be recovered through base rates based on the Companies’ respective revenue requirements is shown in NS Ex. 7.8, column H, and PGL Ex. 7.8, column H. Id., NS Ex. 7.0 REV at 16; PGL Ex. 7.0 REV at 17.
Accordingly, the Companies propose to update Rider UEA to reflect the updated uncollectible amount to be recovered in base rates.

PIO witness Cebulko questioned why uncollectible amounts were included in the customer charge. PIO Ex. 1.0 at 106. As Ms. Egelhoff explained, the Commission has previously ordered that certain charges—including the uncollectible expense adjustment, as filed under Rider UEA—be included in the same line item as the Customer Charge on customer bills. NS-PGL Ex. 17.0 REV at 17.

b. PIOs’ Position

PIO witness Cebulko questioned the Company’s calculation of customer-related unit costs includes $3.21/customer per month in uncollectible accounts. Uncollectible accounts or bill debt are a function of economic circumstances and are not directly caused by adding another customer to the system, as “customer costs” typically are. Economic fluctuations do not neatly map to any form of classification. However, PIO asserts that including uncollectible accounts in the customer charge disproportionately impacts low-use customers who also tend to be low-income. There is thus a risk that including uncollectible accounts in the customer charge could exacerbate customer debt for those most disproportionately impacted by fixed charge increases. In addition, the Company’s customer charge includes a substantial $5.86/customer per month in Administrative General expenses. PIO argues the Commission should not allow these charges in the customer charge. PIO Ex. 1.0 at 106.

c. Commission Analysis and Conclusion

The Commission previously ordered that the uncollectibles expense adjustment under Rider UEA be included in the customer charge on a customer’s bill. The Companies’ request that the Commission approve the proposed revisions to Rider UEA-GC, Uncollectible Expense Adjustment – Gas Costs, to reflect the proposed Uncollectible Factors arising from data in this proceeding, as reflected in NS Ex. 7.8 and PGL Ex. 7.8, and the Companies’ proposal to update Rider UEA to reflect the updated uncollectible amount to be recovered in base rates. The Commission finds that the Companies’ updates to Rider UEA reflect the updated uncollectible amount to be recovered in base rates and are therefore approved.

2. Requirements of Prior Commission Orders (PGL only)

Peoples Gas states that as a Condition of Approval 44 (“COA 44”) in Docket No. 14-0496, Peoples Gas is required, with input from RESA, to prepare a report concerning the following issues:

1. Enroll from your wallet capability;
2. Allowing Alternative Gas Suppliers to bill for non-commodity charges on the utility consolidated bill (regardless of whether Peoples Gas and/or North Shore provides this service to a non-utility affiliate);
3. Improvement to enrollment process;
4. Pooling Charges;
5. Restoration of Intraday Nominations;
6. Billing Services Agreement;
7. Purchase of Receivables Program; and
8. Percentage of Income Payment Plan.

Peoples Gas notes that it has provided RESA with the final report. RESA and Peoples Gas have discussed Items 1, 4, and 8. After discussing with RESA, Peoples Gas implemented Items 3, 5, 6, and 7. Peoples Gas explains that Item 2 is not applicable as it does not have affiliates providing non-utility services to customers in the Peoples Gas service territory.

Peoples Gas explains that pursuant to the Commission’s final Order in Docket Nos. 14-0244/14-0255 (cons.), Peoples Gas has developed communication to its customers to assist customers in selecting between the heating versus non-heating designations of S.C. No. 1. The communication also encouraged customers to call a contact number for an inspection if they were unsure if their service was classified correctly. The communication was sent to customers in February 2015. Peoples Gas notes that it received just under 5,000 inquiries as a result of this communication.

3. Future Rate Proceedings
   a. Companies’ Position

The Companies state that in rebuttal testimony, AG witness Larkin-Connolly asked the Commission to consider requiring the Companies to file joint rate cases in future proceedings, claiming joint cases would be more efficient. AG Ex. 8.0 at 46. Not only should this request have been raised in direct testimony, but there is no requirement for utilities existing in a common holding system to file joint rate cases. Nor is there any reason to instigate one. The Companies contend that a utility may file for a rate increase at any time. BPI 1, 136 Ill. 2d at 219. The Companies are separate utilities serving different service territories and customers with separate costs of service and revenue requirements. The Companies explain that one company may need to file a rate case in a year that the other does not. In this scenario, it would be less efficient to require the other company to file, too. The Companies need flexibility to determine how to operate their separate businesses. Moreover, when both companies file rate cases in the same year, consolidation is a sufficient mechanism for increasing efficiency.

b. AG’s Position

AG witness Larkin-Connolly asked the Commission to consider requiring the Companies to file joint rate cases in future proceedings, claiming joint cases would be more efficient. Mr. Larkin-Connolly states that it is unclear why Peoples Gas and North Shore file their rate cases separately, when their proceedings are regularly consolidated, they are owned by the same parent company, they use the same attorneys and witnesses, and offer many similar if not identical proposals. Splitting the costs of a low-income program between Peoples Gas and North Shore customers would inevitably lead to more equitable results, rather than requiring Peoples Gas’ customers to pay between two and three times more than North Shore, Nicor, or Ameren customers would pay for the same program. The Commission should also consider requiring North Shore and Peoples Gas to file as a single company in future proceedings in order to increase
efficiency, reduce costs, and produce consistent, equitable results, for customers in both service territories. AG Ex. 8.0 at 45-46.

c. Commission Analysis and Conclusion

The Commission notes that both North Shore Gas and Peoples Gas are separate companies that are owned by the same parent company. There is no provision under the Act for the Commission to require a Company to file a rate case, let alone requiring separate entities to jointly file. The Companies do not always file rate cases at the same time. Additionally, there has not been any evidence to support the position that there would be any cost savings with this proposal. This request is denied.

X. GROSS REVENUE CONVERSION FACTOR

A. Uncontested Issues

1. Uncollectibles Rate

North Shore’s forecast uncollectibles rate is 0.8413%. NS Ex. 2.0 REV at 34–35; NS Ex. 2.1, Sch. A-2.1, line 2; Staff Ex. 1.0, Sch. 1.07 N, line 2; AG Ex. 1.01 NS, Sch. 7, line 2. Peoples Gas’ forecast uncollectibles rate is 3.5449%. PGL Ex. 2.0 REV at 38; PGL Ex. 2.1, Sch. A-2.1, line 2; Staff Ex. 1.0, Sch. 1.07 P, line 2; AG Ex. 1.01 PGL, Sch. 7, line 2. No party contests these rates and they are therefore approved.

2. State Income Tax Rate

No party contests the Companies’ forecast state income tax rate of 9.5% and it is therefore approved. NS Ex. 2.1, Sch. A-2.1, line 4; PGL Ex. 2.1, Sch. A-2.1, line 4; Staff Ex. 1.0, Sch. 1.07 N, line 4, and Sch. 1.07 P, line 4; AG Ex. 1.01 NS, Sch. 7, line 4; AG Ex. 1.01 PGL, Sch. 7, line 4.

3. Federal Income Tax Rate

No party contests the Companies’ forecast federal income tax rate of 21.0% and it is therefore approved. NS Ex. 2.1, Sch. A-2.1, line 6; PGL Ex. 2.1, Sch. A-2.1, line 6; Staff Ex. 1.0, Sch. 1.07 N, line 6, and Sch. 1.07 P, line 6; AG Ex. 1.01 NS, Sch. 7, line 6; AG Ex. 1.01 PGL, Sch. 7, line 6.

XI. OTHER ISSUES

A. Uncontested Issues

1. Satisfaction of Merger Conditions

When WEC acquired Integrys in 2015, the Commission’s Final Order in Docket No. 14-0496 (“2015 Acquisition Order”) established certain conditions related to both North Shore and Peoples Gas, set forth in Appendix A of the Order. Condition No. 25 of the 2015 Acquisition Order requires the Companies to submit a report every six months on the status of compliance with these conditions “until all conditions have been satisfied or the Joint Applicants petition the Commission and receive approval to cease such reporting requirement, whichever comes first.” 2015 Acquisition Order at 210.

The Commission’s Order in North Shore’s 2021 Rate Case relieved it of compliance requirements with respect to some of those conditions. NS Ex. 1.0 REV at
11. North Shore has now completed its compliance with all of the 2015 Acquisition Order’s conditions. *Id.* at 11. Peoples Gas has also. PGL Ex. 1.0 REV at 16.

Now that it has been more than eight years since the Commission approved the Integrys acquisition, the Companies respectfully request that they be relieved of all remaining conditions of the 2015 Acquisition Order, with which the Companies have complied since June 2015. No party opposes this request and it is therefore approved.

**XII. FINDINGS AND ORDERING PARAGRAPHS**

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

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

5. the test year for the determination of rates herein found to be just and reasonable should be the 12 months ending December 31, 2024; such test year is appropriate for the purposes of this proceeding;

6. for the test year ending December 31, 2024, and for purposes of this proceeding, North Shore’s rate base is $422,113,000;

7. for the test year ending December 31, 2024, and for purposes of this proceeding, Peoples Gas’ rate base is $4,193,982,000;

8. the $765,664,000 original cost of plant for North Shore at December 31, 2021, as presented in North Shore Schedule B-5 is unconditionally approved as the original cost of plant;

9. the $6,557,029,000 original cost of plant for Peoples Gas Light at December 31, 2021, as presented in Peoples Gas Schedule B-5 is unconditionally approved as the original cost of plant;

10. a just and reasonable return which North Shore should be allowed to earn on its net original cost rate base is 6.96%; this rate of return incorporates a return on common equity of 9.38%, on long-term debt of 4.03%, and on short-term debt of 6.25%;
(11) a just and reasonable return which Peoples Gas should be allowed to earn on its net original cost rate base is 6.65%; this rate of return incorporates a return on common equity of 9.38%, on long-term debt of 3.69%, and on short-term debt of 6.06%;

(12) North Shore's rate of return set forth in Finding (10) results in approved base rate operating revenues of $106,146,000 and net annual operating income of $29,379,000 based on the test year approved herein;

(13) Peoples Gas' rate of return set forth in Finding (11) results in approved base rate operating revenues of $1,003,014,000 and net annual operating income of $278,900,000 based on the test year approved herein;

(14) the Commission has considered the costs expended by North Shore and Peoples Gas to compensate attorneys and technical experts to prepare and litigate this rate case proceeding and assesses that a portion of the costs reflected in the evidence are just and reasonable pursuant to Section 9-229 of the Act (220 ILCS 5/9-229). The adjustment to rate case expense previously discussed results in approved rate case expense of $677,294 for North Shore and $4,525,500 for Peoples Gas, and are amortized over 2 years for North Shore and 4 years for Peoples Gas;

(15) North Shore's and Peoples Gas' rates, which are presently in effect, are insufficient to generate the operating income necessary to permit the Companies 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 North Shore and Peoples Gas in their initial filings do not reflect various determinations made in this Order regarding revenue requirement, expenses, cost of service allocations, and rate design; North Shore’s and Peoples Gas’ proposed rates should be permanently canceled and annulled consistent with the findings herein;

(17) North Shore should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $104,652,000, in addition to $1,494,000 of other revenues, which represents a total base rate increase of $11,012,000 or 11.58% 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;

(18) Peoples Gas should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $979,197,000, in addition to $23,817,000 of other revenues, which represents a total base rate increase of $302,794,000 or 43.24% in base rate revenues; such revenues will provide Peoples Gas with an opportunity to earn the rate of return set forth in Finding (11) above; based on the record in this proceeding, this return is just and reasonable;
(19) the determinations regarding cost of service, rate design, and tariff terms and conditions contained in the prefatory portion of this Order are just and reasonable for purposes of this proceeding; the tariffs filed by the Companies should incorporate the rates, rate design, and terms and conditions set forth and referred to herein, including revisions to their Schedule of Rates for Gas Services;

(20) the state income tax rate used in the determination of base rates in this proceeding was 9.50%; the federal income tax rate used in the determination of base rates in this proceeding was 21.00%;

(21) North Shore and Peoples Gas are hereby relieved of compliance with all merger conditions pursuant to Docket No. 14-0496;

(22) the uncollectible expense included in base rates for North Shore shall be $1,104,000 and for Peoples Gas shall be $43,478,000, which excludes amounts recoverable under Rider UEA-GC;

(23) North Shore and Peoples Gas shall file Rider SSC charges (Storage Banking Charge and Storage Service Charge) consistent with the approved revenue requirements;

(24) the Peoples Gas QIP costs related to the 2016, 2017, 2018, 2019, 2020, 2021, 2022, and 2023 QIP costs included in the revenue requirement are subject to review for prudence and reasonableness adjustments in the applicable annual QIP reconciliations;

(25) new tariff sheets authorized to be filed by this Order should reflect an effective date of not less than four business days after the date of filing, with the tariff sheets to be corrected, if necessary, within that time period;

(26) North Shore’s and Peoples Gas’ updated depreciation rates are uncontested and they are approved; and

(27) Staff is directed to prepare and file an initiating Order for the Future of Gas proceeding, no later than 90 days after entry of the Final Order.

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 January 6, 2023, are permanently canceled and annulled.

IT IS FURTHER ORDERED that Peoples Gas and North Shore Gas are authorized to file new tariff sheets with supporting workpapers in accordance with the above Findings of this Order, applicable to service furnished on and after the effective date of said tariff sheets, which date shall be no sooner than four business days after said sheets are filed.
IT IS FURTHER ORDERED that Peoples Gas and North Shore shall revise their Schedule of Rates for Gas Service in accordance with Finding (19) of this Order.

IT IS FURTHER ORDERED that Peoples Gas and North Shore Gas are hereby relieved of compliance with all merger conditions pursuant to Docket No. 14-0496.

IT IS FURTHER ORDERED that the $765,664,000 original cost of plant for North Shore Gas Company at December 31, 2021, as presented in North Shore Schedule B-5 and the $6,557,029,000 original cost of plant for The Peoples Gas Light and Coke Company at December 31, 2021, as presented in Peoples Gas Schedule B-5, are unconditionally approved as the original costs of plant.

IT IS FURTHER ORDERED that Peoples Gas and North Shore shall file Rider SSC charges (Storage Banking Charge and Storage Service Charge) consistent with the approved revenue requirements.

IT IS FURTHER ORDERED that the Peoples Gas QIP costs related to the 2016, 2017, 2018, 2019, 2020, 2021, 2022, and 2023 QIP costs included in the revenue requirement shall be subject to review for prudence and reasonableness adjustments in the applicable annual QIP reconciliations.

IT IS FURTHER ORDERED that Peoples Gas’ and North Shore’s updated depreciation rates are approved.

IT IS FURTHER ORDERED that Staff is directed to prepare and file an Initiating Order for the Future of Gas proceeding, no later than 90 days after entry of the Final Order.

IT IS FURTHER ORDERED that pursuant to Section 10-113(a) of the Public Utilities Act and 83 Ill. Adm. Code 200.880, any application for rehearing shall be filed within 30 days after service of the Order on the party.

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

By Order of the Commission this 16th day of November 2023.

(SIGNED) DOUGLAS P. SCOTT
Chairman