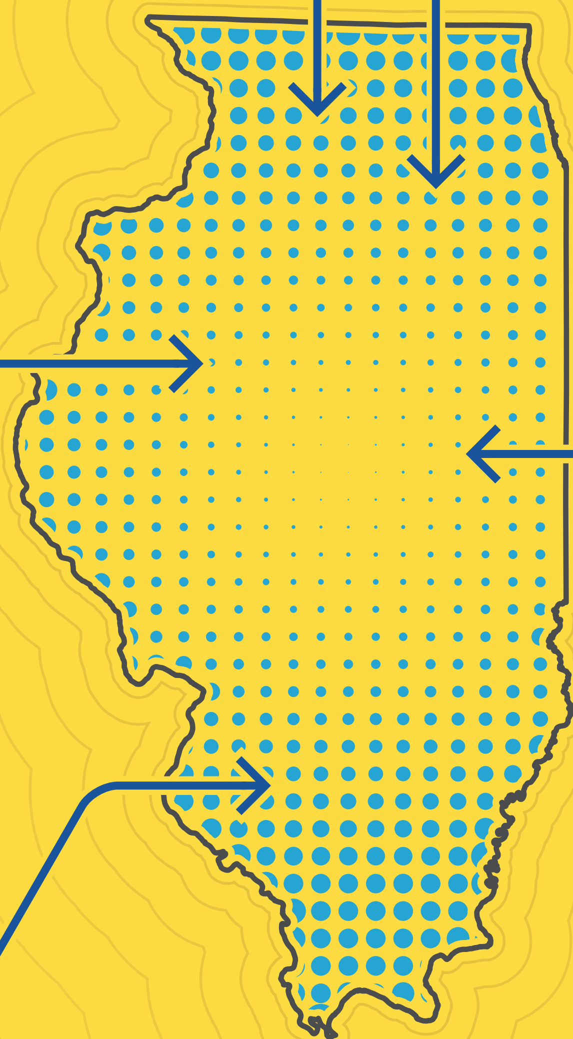
The Future of Gas in Illinois



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BDC

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The Future of Gas in Illinois

Summary

In 2021, Governor Pritzker signed the Climate and Equitable Jobs Act (CEJA), pledging Illinois to 100 percent clean energy by 2050.[1] This economy-wide commitment aligns Illinois with a national and global effort to address the climate crisis by reducing greenhouse gases (GHG) through sector-specific decarbonization targets. While CEJA sets specific targets for reducing emissions in the electric power and transportation sectors, no such milestones are provided for the building sector and its extensive natural gas system, the third largest in the country. Addressing this oversight is critical and urgent as the built environment is responsible for an estimated 46 percent of the state's energy-related emissions, with a significant portion originating from residential and commercial use.[2]

Three-quarters of Illinoisians primarily use natural gas ("methane gas") to heat their homes, making it one of the country's most gas-reliant states. The methane gas consumed in Illinois not only contributes to local and global GHG emissions, but creates unhealthy air pollution in and around buildings, exacerbating existing environmental inequity. Studies have demonstrated that gas

> **"As the State embarks on a journey toward a 100 percent clean energy economy, the gas system's operations will not continue to exist in its current form. Identifying how our gas and electric systems can adapt to meet these goals, and what specific actions should be taken to achieve them, will be an important task for the Commission moving forward."**
>
> *– Illinois Commerce Commission Chairman Doug Scott, ICC Press Release, November 2023*

1 Climate and Equitable Jobs Act, Pub. L. No. P.A. 102-0662 (2021). https://epa.illinois.gov/content/dam/soi/en/web/epa/topics/ceja/documents/102-0662.pdf.

2 RMI,. State-Level Building Electrification Factsheets. "All-Electric Buildings: Key to Achieving Illinois' Climate Goals," State-Level Building Electrification Factsheets (2023), https://rmi.org/insight/state-level-building-electrification-factsheets/.

stoves leak, even when they are not in use; indoor gas combustion aggravates respiratory conditions such as asthma, especially in children and other vulnerable populations; and highly polluted areas often correspond to communities that have been historically divested of infrastructure and other resources (i.e., "environmental justice communities").[3] Community groups, advocates, policymakers, and regulators have begun to take notice of CEJA's lack of attention to the gas distribution system and are advocating for healthier homes and communities as well as voicing concern about the cost of continued fossil fuel investments. At the same time, gas customers have growing incentives to switch to cleaner, more efficient, and safer air- and ground-source heat pumps and electric-resistance or induction stoves.

In late 2023, the Illinois Commerce Commission (ICC) announced that: "if the decarbonization goals of CEJA are to be met, the gas distribution system as currently operated will need to change."[4] In its 2023 rate case orders for the four largest investor-owned gas utilities, the Commission cut record rate hike requests by $240 million or 30 percent and paused the pipeline replacement program of one of the utilities, signaling a shift to tightened regulatory oversight.[5] The ICC also announced a "future of gas" proceeding, joining 11 other state utility commissions and the District of Columbia with proceedings that address long-term gas planning, pathways for emissions reductions and clean energy infrastructure, workforce transition, and low-income ratepayer protections, among other issues.[6]

To assist policymakers, regulators, and advocates in shaping a new framework for gas system planning, this report conducts an in-depth analysis of the infrastructure and investments of the "Big Four" investor-owned gas utilities—Ameren Illinois Company, Nicor Illinois Gas Company, North Shore Gas, and Peoples Gas Light & Coke Company—which together serve approximately 97 percent of the state's gas consumers. We also conduct a cost modeling analysis to assess the likely future levels of revenue and customer payments that each utility will need in order to sustain its operations as customers depart the gas system at a pace in line with the decarbonization of Illinois' building sector.

Our analysis establishes that, while gas service is still being extended in less-dense territories, the expansion of Illinois' gas system overall has come to an end and the market share of gas in home heating has declined each year since 2010.[7] At the same time, Illinois' Big Four gas utilities have embarked on aggressive, long-term capital spending plans over the past decade, growing their gas system investments largely by replacing existing pipelines instead of adding new ones. Together, the Big Four have been investing more than $1 billion annually, largely to replace aging gas infrastructure, and thereby locking in capital spending that gets repaid with a rate of return over 40 to 70 years. As detailed in our Findings and Conclusions (page 7), our modeling analysis finds that:

- **Gas delivery costs are on a steady upward course, regardless of climate policy changes.** If gas utilities continue to increase capital spending at their most recent decadal rate, then annual expenditures across the Big Four utilities would increase from $1.5 billion currently to $2.2 billion by 2030 and $2.9 billion by 2035. Even if the customer base remains stable, ***by 2030 customer rates across the Big Four gas utilities (measured as average delivery cost per customer) would need to rise 45 percent*** on average to pay for increasing gas system costs. By 2035, a 94 percent increase in rates would be required.
- **Illinois' Big Four gas utilities are accumulating stranded asset risk at an escalating rate.** By 2050, the financial risk posed by stranded gas assets will be tens of billions of dollars higher than it is today—on the order of $80 billion—unless

3 For an overview report on gas stove pollution, see Brady Anne Seals and Andee Krasner, Health Effects from Gas Stove Pollution, RMI, Physicians for Social Responsibility, Mothers Out Front, and Sierra Club (2020). See also: Yannai S. Kashtan et al., "Gas and propane combustion from stoves emits benzene and increases indoor air pollution," *Environmental Science & Technology* (2023) and Zachary D. Weller et al., "Environmental injustices of leaks from urban natural gas distribution systems: Patterns among and within 13 U.S. metro areas," *Environmental Science & Technology* (2022).

4 Illinois Commerce Commission, 2023 Rate Case Order for Ameren, Docket 23-0067 (November 16, 2023), p. 93, https://www.icc.illinois.gov/docket/P2023-0067/documents/344282/files/601209.pdf.

5 Citizens Utility Board, "Q&A on ICC gas rulings and how they impact customers" (December 19, 2023), https://www.citizensutilityboard.org/blog/2023/12/19/qa-on-icc-gas-rulings-and-how-they-impact-customers/.

6 See BDC's summary of active Future of Gas proceedings as well as their tracker: https://buildingdecarb.org/decarbnation-issue-2.

7 U.S. Census Bureau, American Community Survey, ACS 5-year, Table S2504, https://data.census.gov/table/ACSST1Y2022.S2504?q=S2504&g=040XX00US17_160XX00US1714000.

gas utilities begin to wind down and substantially limit their infrastructure investments.

Regulators and policymakers face a time-sensitive need to wind down and avoid the creation of additional long-lived methane gas assets, since further infrastructure investments in the gas distribution system may well become uneconomic and expose the market valuation of Illinois' gas utilities to negative consequences. Lower levels of spending today and over the near term will reduce the risk of unrecovered costs.

Illinois stands at the threshold of yet another energy transition, this time away from fossil fuels and towards clean, renewable energy. This transformation is unfolding as the result of ongoing technological change and innovation, significant policy change dedicated to lowering GHG emissions, and unprecedented federal and state incentives. Consumer preferences are changing too, as awareness of the need to decarbonize grows and there is a better understanding of the importance to health and safety of cleaner space and heating technologies. But without intervention for the public good, non-gas alternatives will be taken up in a sporadic and dispersed manner, mostly in more affluent areas. Other first adopters will likely be larger consumers, such as college campuses and hospitals. An overbuilt, underutilized, high-cost gas system will come to serve a dwindling base of energy-burdened customers living in more urbanized areas and environmental justice communities. As a result, those with the least ability to leave the system will become increasingly burdened.

Illinois today is on a path toward just such an *unmanaged gas transition*—the most costly path that the state could follow and one that will magnify inequities and obstruct climate objectives. The outcome from the customer perspective is rising delivery costs, the main charge on customer bills. In 2020, nearly one in four Illinois households were unable to meet their basic energy needs,[8] and for them, the expensive future of gas raises intractable options. To its credit, Illinois recently adopted a tiered, income-based rate structure for gas rates—Illinois is only the second state in the country to do so[9]—but that framework was not designed for a gas system in decline. To the contrary, this report finds that achieving the state's energy affordability, equity, and environmental justice goals is not possible if Illinois continues its heavy reliance on methane gas.

The thesis of this report is simple, even though the task is not: ***Illinois is in need of a managed transition away from methane gas to pave the way for a cleaner, safer, and more cost-effective energy future***. The transition towards clean energy is already in motion, supported by policies, technological advancements, regulatory frameworks, and growing consensus about the imperative to combat the climate crisis. These developments are disrupting the status quo of the gas system at the very time that it faces growing long-term cost challenges due to the substantial investments that have been made over the past decade and which continue to this day.

A managed gas transition is a comprehensive strategy involving regulatory oversight and stakeholder collaboration to phase out pipeline delivered methane gas for clean energy, while ensuring safety, reliability, and affordability. This approach is marked by coordinated investments and actions from utilities, consumers, and policymakers. It includes the deployment of non-GHG-emitting technologies, policy reforms, and safeguards for affected communities and workers, aligning with decarbonization goals for a sustainable energy shift without undue hardship or service interruptions.

An emergent approach for a managed transition is neighborhood-scale building decarbonization, which focuses on transitioning entire street segments, developments, or neighborhoods to decarbonized energy sources and electric appliances.[10] This strategy is critical for avoiding the pitfalls of escalating customer costs and deepening inequities. In Illinois, following the directives of CEJA, any

8 U.S. Energy Information Administration, 2020 RECS Survey Data, "Highlights for household characteristics of U.S. homes by state, 2020," https://www.eia.gov/consumption/residential/data/2020/state/pdf/State%20Household%20Characteristics.pdf.

9 See Section 3.H of this report.

10 Kristin George Bagdanov, Claire Halbrook, and Amy Rider, *Neighborhood Scale: The Future of Building Decarbonization*, Building Decarbonization Coalition and Gridworks (December 2023), https://buildingdecarb.org/resource/neighborhoodscale.

> **“Collectively, the Big Four gas utilities are allocating roughly $1.5 billion annually to replacing aging gas system infrastructure and other related capital improvements.”**

approach to a managed transition should structurally integrate equity into its policies and frameworks.

An unmanaged transition is not a viable option for ratepayers, utilities, investors, or the general public. The question confronting Illinois regulators and policymakers now is not unmanaged versus managed, but rather what kind of managed transition should be implemented to guide and shape Illinois’ future beyond gas. Given the urgency of reducing greenhouse gas emissions, clear signals are needed to establish a robust timeline for implementing this managed gas transition. Proactive planning for the future of gas, and a future beyond gas, is Illinois’ best opportunity to achieve an equitable, safe, and cost-effective energy transition.

Key Findings and Conclusions

1 The future of gas in Illinois is marked by substantial financial, climate, health, and environmental costs as well as increasing competition from continuously improving clean energy alternatives.

The Illinois gas system has largely transitioned from expansion to maintenance, with utilities focusing more on replacing aging pipelines than adding new ones to extend their networks.

After World War II and into the 1980s, the gas system saw rapid growth, with revenue from an expanding customer base covering the costs of reaching new customers. Presently, as a mature industry, the gas sector faces two main challenges: first, customer growth has plateaued due to market saturation; and second, the industry is entrenched in an extensive and costly phase of infrastructure replacement, targeting aging pipelines and associated gas facilities. More than a third of the Big Four's gas distribution systems (over 21,000 miles) was installed prior to 1970, and is now more than 50 years old and reaching the end of its lifespan. Collectively, the Big Four gas utilities are allocating roughly $1.5 billion annually to replacing aging gas system infrastructure and other related capital improvements.

Statewide, gas delivery costs are on a steady upward course, independent of climate policy changes.

These escalating expenses will become a significant burden for Illinois' gas consumers, even outside the context of the energy transition. Consumer bills for gas service are made up of charges for gas used and the utility's delivery costs. Delivery charges account for all expenses associated with the reliable and safe transportation of gas to customers, including the costs of system operation, maintenance, repair, customer service, administration, taxes, and repaying utilities for their capital investments (capital spending is paid back over many years). As the customer base remains static and initiatives to replace aging infrastructure progress, delivery charges are poised to rise continuously.

The modeling findings of this report demonstrate concerning consequences for Illinois:

- Assuming the state's Big Four gas utilities continue their capital spending on a business-as-usual trajectory, by 2030 the utilities would, on average, need a 45 percent increase in their combined revenue (i.e., "revenue requirement") to pay for these increased delivery costs, even if the gas customer base remains stable. By 2035, the revenue requirement for each company roughly doubles from its 2024 level.
- If rate cases were to occur annually over the next six years (2024-2030), customer rates on average would need to rise by approximately 8 percent each year to pay for the increasing costs of the gas system.
- Even assuming a best-case scenario of flat capital spending with moderate customer departure, by the mid- to late-2030s average delivery costs per customer still double for each gas utility. This reflects the strong "undertow effect" of high levels of prior capital spending that have been baked into the rate bases of each utility, reflecting prior cost recovery decisions.

Illinois is already actively transitioning away from fossil fuels.

Innovations in heat pump technology, along with advancements in water heating and electric induction cooking, are prompting gas customers to switch to cleaner, more efficient, and safer alternatives. However, these shifts, while aligned with the state's climate objectives, will lead to higher average delivery costs for remaining gas customers, as the gas system's costs will be distributed across fewer customers. Since 2010, the market share of utility gas for home heating in Illinois has consistently decreased, with electric heating becoming more prevalent. Each gas territory in Illinois should anticipate customer attrition and reduced demand for gas in the near to medium term. As more customers move away from the gas system, the challenge of increasing delivery costs will intensify, leaving fewer customers to bear the cost burden. This report finds that:

- Roughly a decade from now, continued business-as-usual spending accompanied by ***moderate*** customer departures would more than double average delivery costs for each gas utility.
- ***High*** customer departures cause average delivery costs to roughly triple by 2035.

Illinois' heavy reliance on pipeline gas is accompanied by significant climate and societal costs from both leaked and combusted methane.

In Illinois, methane gas combustion in the residential and commercial sectors emits about 32 million metric tons of carbon dioxide annually, which equates to an annual social cost of roughly $6.7 billion, per the EPA's latest carbon damage estimates. Leaked methane from the state's gas system conservatively adds another $624 million per year to the social cost of Illinois' greenhouse gas emissions, but the actual cost of emissions may be several times higher since fugitive methane tends to be significantly underestimated. Beyond its climate-related harm, leaked and combusted gas occurring in and around people's homes and workplaces contribute to respiratory ailments, including asthma, as well as premature deaths. These air pollution-related effects disproportionately occur in low-income and environmental justice (EJ) communities where energy insecurity and high energy burdens are also concentrated.

2 The riskiness of the financial future of gas is escalating as Illinois' four largest gas utilities accumulate substantial amounts of unrecovered capital costs on their balance sheets.

Illinois faces a growing stranded gas asset problem that, if unaddressed, will jeopardize all parties involved—ratepayers, utilities, investors, and even the general public.

As the Illinois economy switches to clean, renewable energy sources, a new gas main installed today on a city street (with its accompanying service lines) is likely to become unused or underutilized during its design lifetime, stranding the physical capital. Some portion of the value of the asset is also likely to be stranded, since the cost of the new main, services, and meters won't have been fully recovered by the time the asset is abandoned. This study finds that, by 2050, the financial risk posed by stranded gas assets will be billions of dollars higher than it is today unless gas utilities begin to wind down and substantially limit their infrastructure investments:

- From 2016 to 2022, the value of unrecovered assets for the state's Big Four gas utilities doubled to $13.4 billion.
- If current capital spending levels continue, the value of unrecovered assets will increase sixfold to $80 billion by 2050, increasing the risk of stranded assets substantially as gas customer departures and emissions-related policies render these assets unnecessary.

Regulators and policymakers face a time-sensitive need to wind down and avoid the creation of additional long-lived methane gas assets, since further infrastructure investments in the gas distribution system may well become uneconomic and expose the market valuation of Illinois' gas utilities to negative consequences. Lower levels of spending today and over the near term will reduce the risk of unrecovered costs.

3 Illinois is on a path toward an unmanaged gas transition—the most costly path that the state could follow and one that will magnify inequities and obstruct climate objectives.

An unmanaged gas transition characterized by sporadic and dispersed building electrification necessitates maintaining the infrastructure of the entire gas system, incurring high gas system costs despite reduced utilization.

Unless redirected, Illinois is on course to maintain its entire gas system indefinitely. If current spending levels continue, new capital expenditures on gas infrastructure by the Big Four gas utilities will total approximately $100 billion through 2050, resulting in total cumulative costs of roughly $170 billion as that direct capital cost is paid back, accompanied by the return on equity, operations and maintenance expenses, and taxes. The majority of cost recovery would occur through the end of this century. Continued investments at this scale will significantly increase the prospect of stranded assets, likely leading to legal claims—the resolution of which could burden energy ratepayers and taxpayers for generations to come. It should be noted that these cost estimates do not include the additional operating costs required for Illinois gas utilities to comply with PHMSA's proposed revised regulations concerning pipeline leak detection and repair, nor do they include new federal fees on methane emissions from the upstream and midstream parts of the utility gas systems that take effect in 2024. While these changes would benefit public safety and help lower emissions, they will result in higher operational and maintenance expenses that will add to customer rates.

> **"If current spending levels continue, new capital expenditures on gas infrastructure by the Big Four gas utilities will total approximately $100 billion through 2050, resulting in total cumulative costs of roughly $170 billion"**

Achieving the state's energy affordability, equity, and environmental justice goals is not possible if Illinois continues its heavy reliance on methane gas.

Without intervention for the public good, non-gas alternatives will come to dominate in more affluent areas as increasing gas delivery charges incentivize customers to depart the gas system. Other first adopters will likely be larger consumers, such as college campuses and hospitals (gas utilities suffer noticeable revenue hits with these departures). An overbuilt, underutilized, high-cost gas system will come to serve a dwindling base of energy-burdened customers living in more urbanized areas and environmental justice communities (nearly one in four Illinois households are already energy insecure). Those who are least able to leave the gas system will face increasing gas delivery charges with no coordinated, equitable access to new energy technologies. While low-income gas ratepayers in Illinois will soon secure some degree of affordability protection via the new low-income discount rate, the resilience of this new rate structure could be challenged as costs for remaining ratepayers continue to rise.

Alternative gases such as renewable natural gas are not a solution to Illinois' gas transition challenge and would exacerbate cost challenges while leaving the climate and health costs of the gas system unchanged.

Renewable Natural Gas (RNG) is an exceptionally expensive decarbonization pathway that does not create new net value for customers. RNG is produced from the energy- and capital-intensive processing of biomass into pipeline-quality methane. The waste feedstocks best suited for RNG (e.g., landfill gas) are scarce and at lower cost could be used to create other products, such as electricity. Meeting current gas demand from RNG would require vast cultivation of energy crops such as switchgrass. These crops may result in significant environmental and economic trade offs due to the expanded agriculture required and their higher economic value if used in other sectors. Additionally, scaling RNG for heat will likely be further constrained by new federal incentives for transportation biofuels and carbon sequestration. Ultimately, RNG at any scale would impose burdensome costs on Illinois energy customers, further incentivizing customers to depart the gas system. Hydrogen faces similar cost-effectiveness challenges and has limited ability to substitute for methane in existing pipelines.

4 A strategically managed gas transition, under the guidance of an empowered Illinois Commerce Commission (ICC), can pave the way toward meeting the state's climate targets while creating cost savings and reducing the risks inherent in an unmanaged transition.

By limiting and cutting back capital spending on the gas system today, the ICC can mitigate rate burdens and reduce the risk of stranded gas assets, thereby safeguarding consumers, taxpayers, and investors.

Our analysis indicates that, compared to a business-as-usual approach, holding annual capital expenditures steady at 2024 levels would:

- Lower average gas delivery costs by roughly 25 percent in 2040.
- Reduce the value of unrecovered assets in 2050 by 59 percent for the Big Four gas utilities, thereby significantly lowering stranded asset risk.

Gas customer attrition, however, will offset these anticipated savings and risk mitigation. Addressing the challenge of a shrinking customer base and lower gas demand requires a meticulously planned gas transition that eschews investments in the gas infrastructure at critical locations and time periods while concurrently channeling resources into non-fossil alternatives.

By coordinating gas and electric infrastructure planning, a managed transition enables the redirection of gas investments to non-fossil alternatives, creating financing opportunities to ensure clean energy alternatives are available to more customers.

As the Commission noted in its 2023 rate case orders, "the question is not whether pipeline replacements generally improve safety and reliability, but what types of pipes are to be replaced, to what degree safety and reliability are affected, at what pace, and at what cost."[11] Our analysis sheds light on one dimension of this opportunity cost, showing that the per customer savings from avoiding the replacement of a mile of gas distribution main ranges from approximately $10,025 to $28,145 across the three largest gas territories. These calculations pertain to direct main installation costs only and do not include additional costs such as updated service lines, meter adjustments, net salvage rates, utility return on investment, or long-run operations and maintenance. Strategically redirecting these savings towards the neighborhood-scale implementation of non-gas-pipeline alternatives such as whole-home electrification and thermal energy networks has the triple-benefit of achieving emissions reductions, providing more equitable access to non-fossil alternatives, and limiting ratepayer impact to those who remain on the gas network.

Reforming regulatory frameworks for gas and electric utilities can enable the energy sector to adapt to rapidly changing circumstances.

For nearly a century, gas and electric utilities have operated under separate regulations due to their distinct services—gas primarily for heating and electricity for lighting and powering appliances. Each utility type has been granted a monopoly in its service area, predicated on the absence of competition between the two. However, this landscape is changing, especially in heating, where advancements in heat pump technology offer a competitive alternative to traditional gas furnaces. Without timely regulatory intervention, this burgeoning competition could put upward pressure on both gas and electric costs and lead to heightened safety issues.

> **"The per customer savings from avoiding the replacement of a mile of gas distribution main ranges from approximately $10,025 to $28,145 across the three largest gas territories."**

Greater coordination between gas and electric utilities can allow for gas system right-sizing and electric system modernization. This coordination could include integrated supply and demand forecasting by gas and electric utilities and systemwide planning based on a common set of assumptions regarding load forecasts and customer attrition and/or growth. In addition, alternative rate designs that better reflect the marginal cost of generating and delivering power and the relative social costs of electricity and gas are important for resetting the economics of energy and the operational costs of gas vs. electric appliances for consumers. These basic reforms could play a strong role in guiding a successful energy transition for Illinois.

11 ICC, Ameren Illinois Company, Order, Docket P2023-0067 (November 16, 2023), p. 90.

Recommendations

The following policy and regulatory recommendations outline the next steps identified in this report. Some of these items can be accomplished in multiple ways, e.g. legislation and/or regulation.

1 Set clear decarbonization objectives to accelerate change in the building sector

Responsible Entities: **The General Assembly in consultation with the ICC, the Department of Agriculture, the Department of Natural Resources, and the Illinois Environmental Protection Agency.**

While CEJA codified the economy-wide goal of 100% clean energy by 2050 and created nation-leading provisions for decarbonizing electricity and transportation, it did not set comprehensive targets for decarbonizing buildings. Subsequently, the federal Inflation Reduction Act established a clear direction toward electrification with industry-catalyzing incentives for building electrification. This direction creates an opportunity for Illinois to build on CEJA and join other leading states in driving forward economy-wide decarbonization.

- Establish specific, achievable near- and long-term goals for building decarbonization, akin to achieving one million EVs by 2030.
- Ensure affordable electricity can be provided to customers through sound clean energy supply policy and the design of electrification-friendly electric rates that enable electric heating customers to spread costs across the year.
- Provide financial support and technical assistance to community-based organizations for educational efforts on the components and benefits of building decarbonization. Funding should be prioritized for environmental justice communities.
- Conduct a labor study that seeks to determine the expected job gains and losses associated with a managed transition off of the gas system.
- The Assembly and relevant agencies should clarify how alternative fuels in an economy-wide context will and won't be used to support Illinois' decarbonization goals. Policies should place guardrails on adverse outcomes (e.g., unsustainable energy crop practices) and direct alternative fuels to their highest-value uses.

2 Halt expansion of the gas system

Responsible Entities: **ICC, Capital Development Board, Municipalities**

New gas connections lock customers into the gas system for decades and instantly increase emissions. Electrification in new construction is typically more cost-effective than electrifying later. Further, the cost of gas pipeline extensions and new hook-ups can require substantial investments.

- Prioritize efforts to reform pipeline extension allowances. The ICC's recent order to open a "future of gas" proceeding noted that the proceeding should investigate and propose changes to such rules. Action on this topic can and should be accelerated in the proceeding and need not wait for other elements of the proceeding to be addressed.
- Illinois municipalities should adopt the recently developed Stretch Energy Code, which requires buildings using combustion to be prewired for electrification and to have more stringent energy efficiency requirements. Given the significant long-term challenges associated with the gas system, during the next iteration of the code's development the Capital Development Board should more thoroughly consider all-electric requirements.

3 Limit reinvestment in the gas system and support non-gas-pipeline alternatives

Responsible Entities: **ICC, Utilities**

Ongoing spending on the gas system, particularly on assets with multi-decade, depreciable lifetimes, creates inherent cost recovery risks in a future of declining gas consumption. Simultaneously, an aging gas system poses climate, health, and safety risks that need to be managed. Future investment needs to more proactively balance these issues and avoid the historical approach of maintaining the system for indefinite use.

- Advanced leak detection and repair strategies should be encouraged to enhance public safety and avoid unnecessary pipeline replacements. Annual reporting by utilities on their leak detection and repair activities, including the number of leaks by class, would enhance public transparency. Illinois should consider proactively adopting the proposed new federal regulations on leak detection and repair since these would significantly strengthen current gas utility practices in Illinois.
- The ICC should limit capital investment to what is necessary to maintain system integrity through the transition, restricting capital spending on replacement to the highest-risk pipes and the most critical projects. Projects above a certain value could be held to a higher standard to demonstrate prudency and reasonableness.
- Develop and implement a comprehensive evaluation framework for non-gas-pipeline alternatives to ensure that the most cost-effective solutions are deployed to maintain reliability, reduce emissions, and ensure safety and system integrity.

4 Embark on long-term right-sizing of the gas system

Responsible Entities: **ICC, Utilities, IEPA**

The gas system needs to be right-sized for a future in which gas demand and customers are a fraction of what they are today. The specific interventions for right-sizing the system need to be flexible, based on local needs and conditions and in response to emerging technologies and clean energy availability. While these considerations may evolve over time, there are several actions the ICC can take today to support an equitable gas transition:

- Require coordination between gas and electric utilities in order to: develop plans for gas system right-sizing and electric system modernization; integrate gas/electric supply and demand forecasting and planning based on a common set of assumptions regarding load forecasts and customer attrition or growth; and develop alternative rate designs that are better aligned with the marginal cost of generating and delivering power and the relative social costs of electricity and gas.
- Develop location-specific transition plans that encourage customer and municipal involvement and initiative by granting public access to data on gas assets (e.g., areas targeted for possible retirement), electricity systems (distribution system capacity maps), and thermal resources (e.g., geothermal feasibility maps developed by the state).
- Develop selection criteria for retiring or transitioning gas lines.
- The ICC should instruct gas and electric utilities to conduct integrated planning exercises to understand where system right-sizing can be advanced and what infrastructure decisions are necessary to achieve this.

Report Structure

Energy In Illinois (Section 2) provides an historical overview of energy systems change over the last two hundred years in Illinois and situates the current transition away from fossil fuels in that evolving timeline. A brief history of gas in Illinois is provided, tracing its evolution from a single pipeline in Chicago carrying "coal gas" in the 1850s to a statewide network of 64,000 miles of methane gas distribution and transmission pipelines. We analyze the disruptive forces that are eroding the competitive advantage of the gas system, including the availability of clean energy technologies that offer customers appliances that are safer and more efficient than their existing gas counterparts.

The Gas System Today (Section 3) provides an in-depth overview of the state of the gas system in Illinois today. It explains the flows of gas through the economy—virtually all of the state's gas is imported—and breaks down the structure of the Illinois gas system, focusing on the four major investor-owned gas utilities. We explain how the industry is regulated and how utilities recover their costs through the rates paid by Illinois gas customers. The infrastructure of each utility is profiled and we describe trends in capital spending, customers, and gas therms sold. (See individual gas utility profiles on page 30)

RNG Won't Fix the Future of Gas (Section 4) explores the viability and implications of leveraging renewable natural gas (RNG) as a means to decarbonize Illinois' gas distribution system. This section presents a comprehensive analysis of RNG's production challenges, environmental impact, and economic feasibility, ultimately arguing that, in contrast to gas company proposals, the pursuit of RNG for heating is not an effective or sustainable path towards achieving Illinois' clean energy objectives.

Cost Analysis for the Future of Gas in Illinois (Section 5) investigates what the future of gas holds for ratepayers and gas utilities in terms of the costs of the gas system. These costs have increased significantly over the past decade. We explore the financial implications for customers using a modeling approach that allows for variations in gas system capital spending and customer departures due to up-take of clean, efficient non-gas technologies. Our modeling relies on utility data filed with the ICC and on the latest authorized financial variables set by the Commission in its 2023 rate case orders. Finally, we evaluate the potential financial magnitude of the gas industry's stranded asset problem. Understanding and managing the risk of stranded gas assets is a paramount task confronting regulators at this critical juncture in the energy transition. This risk matters to utilities and their investors, but also to gas customers and ultimately to taxpayers, since all parties may be affected by stranded gas assets.

Toward a Managed Transition Off of the Gas System (Section 6) takes stock of the critical decision facing all Illinois stakeholders with respect to the state's gas distribution system: Should Illinois let an unmanaged transition off methane gas unfold or should it pursue a managed transition? The former involves limited changes to utility regulation and reliance on market forces for a transition, while the latter requires the active involvement and coordination of the ICC, the General Assembly, and the Executive Branch in order to bring gas utility planning and utility regulation into alignment with climate goals, and to develop a strategic, orderly path for downsizing existing gas infrastructure. We examine the consequences of an unmanaged approach and provide a policymaking framework to guide a managed gas transition.

Section 2

Energy in Illinois: Two Centuries of Change

A. Key takeaways

- Over the past 200 years, Illinois has undergone multiple, overlapping energy transitions. While the current transition has similarities with prior transitions (substituting more efficient, less polluting, and ultimately more cost-effective fuels), there are important differences. Today's energy transition is urgent due to the need to reduce climate-damaging emissions. Supported by abundant public-sector financial incentives and subsidies, it will require unprecedented coordination and management to control costs and create equitable energy access.
- The gas system as we know it today began with piped manufactured coal gas in the 1860s, which initially relied on localized coal supplies from nearby mines. After World War II, innovations in pipeline fabrication, welding, and joining allowed for the exponential expansion of interstate pipeline transmission networks and the laying of thousands of miles of intrastate gas distribution pipeline.
- In terms of greenhouse gas emissions, Illinois' heavy gas reliance creates an annual social cost in excess of $7 billion per year, per the U.S. Environmental Protection Agency's latest carbon damage estimates. Beyond its climate-related harm, leaked and combusted gas in people's homes and workplaces contributes to respiratory ailments, including asthma, as well as premature deaths. These air pollution-related effects disproportionately occur in lower-income and environmental justice (EJ) communities where energy insecurity and high energy burdens are also concentrated.
- Illinois' gas industry is in its post-expansion phase. Customer growth is relatively stagnant and fuel consumption has leveled off. As a result, large capital investments in the gas system are no longer offset by the addition of new customers and instead require higher delivery charges for existing gas customers.
- Three primary factors are shaping the transition away from fossil fuels and towards clean, renewable energy: rising gas infrastructure costs, clean energy policies, and technological advancements.

B. Introduction

For a resident of Illinois younger than 55 years, it would be difficult to imagine a time when homes weren't heated by "natural" or methane gas and lights weren't powered by electricity. Today's dominant energy system may seem permanent and inevitable. But a look back at the last two centuries shows us that Illinois has undergone a succession of overlapping energy system transitions. The lineage of fuels for space heating and cooking in urban and suburban areas has included wood, coal, manufactured gas derived from coal, and the methane gas that dominates the market today, while the predecessors for electric lighting include animal fat candles, oil lamps, kerosene, and pipeline-delivered coal gas.

Now, nearly a quarter of the way into the 21st century, Illinois stands at the threshold of yet another energy transition, this time away from fossil fuels and towards clean, renewable energy. This transition is being driven by three primary factors, which together are disrupting the state's gas-driven energy system: rising gas infrastructure costs, net-zero emissions policies, and technological advancements.

1. **Rising gas infrastructure costs.** While significant amounts of pipeline have been replaced in the last decade, the remainder continues to age and will require significant capital upgrades to replace each successive cohort of retiring pipes in order to maintain safety and reliability. In addition, new federal regulation directed at improving safety, increasing reliability, and lowering fugitive gas will continue to raise per-mile operations and maintenance expenses.
2. **Clean energy policies.** Policies and incentives to reduce greenhouse gas emissions, achieve environmental justice, and promote clean energy jobs are accelerating the transition off of fossil fuels. These policies must continue to be refined to include sector-specific targets and roadmaps for the built environment to achieve these goals.
3. **Technological advancements.** Rapid technological change is producing new equipment and appliances that are far more efficient, comfortable, and increasingly cost effective, compared to their fossil-fuel counterparts. In addition, unprecedented financial incentives at the federal, state, and local level are helping to transform the market for the development and implementation of clean energy technologies.

This section explores this pivotal moment for the Illinois energy economy through the lens of the complex historical forces that created the state's formerly dominant energy systems. We begin by tracing the rise of the gas system in Illinois and considering what was required for methane gas to become Illinois' dominant energy regime. We then locate where the gas distribution industry is in its own industry life cycle and assess the greater toll of methane gas. Finally, we look at the gas system in the context of increasing competition from non-fossil alternatives and consider how the current transition parallels and diverges from prior energy transitions in Illinois.

C. Origins of the gas system in Illinois

Illinois' first gas mains were laid in the 1850s in Chicago. These early cast iron pipes carried coal gas, which was produced by heating coal at very high temperatures at nearby plants. In the city, this gas was first used to provide light, displacing oil lamps and the lamplighting industry. While there were clear advantages in terms of convenience, brightness, and cost, there were immediate social consequences to this new and highly polluting industry, the impacts of which can be seen in Chicago to this day: "Huge coal gasification plants [were] usually located in poor and undesirable neighborhoods because of their noxious odors."[12] These communities were also the last to benefit from new technologies: "In Chicago the [gas] companies generally did not extend services in working class neighborhoods, where few residents could pay for the expensive service....In fact, the city government operated under no sense of duty to deliver an equitable share of modern services to every neighborhood."[13] In this era before state regulatory commissions, when the norms of private utilities and their commitments to public service were in formation, gas companies had an outsized and lasting impact on the energy landscape of Chicago and its people, and by extension, Illinois.

When electricity displaced coal gas as the preferred energy source for lighting at the turn of the 20th

12 Christopher Castaneda, *Invisible Fuel: Manufactured and Natural Gas in America, 1800-2000,* (New York: Twayne Publishers, 1999), p. xvi.
13 Harold L. Platt, *The Electric City: Energy and the Growth of the Chicago Area, 1880-1930* (Chicago: University of Chicago Press, 1991), p. 14.

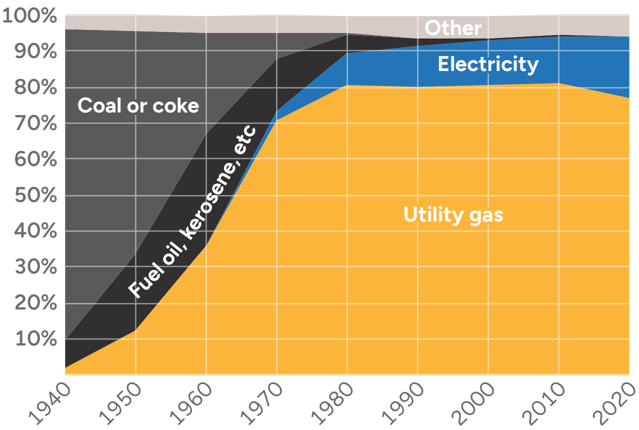
> **"In Chicago the [gas] companies generally did not extend services in working class neighborhoods, where few residents could pay for the expensive service....In fact, the city government operated under no sense of duty to deliver an equitable share of modern services to every neighborhood."**

century, the by-then established gas industry underwent a major evolution by shifting its focus to new end-uses like space heating and cooking, which to that point had been reliant on both wood- and coal-fired furnaces and stoves. This technological advancement led to the bifurcation that still characterizes our current energy system: electricity providing lighting and gas providing the fuel for home heating, with limited competition between the two services for home appliances such as stoves and eventually clothes dryers.

In 1940, the overwhelming majority of households in Illinois (87 percent) still heated their homes with coal or coal gas (see Figure 2.1). But the end of World War II catalyzed the rise of the current utility gas system, which required drilled (and eventually fracked) methane gas piped into Illinois via thousands of miles of pipes. By 1980, 81 percent of Illinois residents relied on piped methane gas for their home heating.

While Illinois' reliance on coal was supported by the state's own coal resources—Illinois has the largest bituminous thermal coal reserves in the country[14]—relying on pipeline gas requires Illinois to depend on external sources. Illinois imports virtually all of its methane gas (see Section 3.D for more information). The ability to import vast quantities of methane gas required the creation of long-distance, interstate networks along with the installation of thousands of miles of intrastate gas transmission and distribution pipeline networks across Illinois. Because it has to purchase virtually all of its gas from out of state, Illinois has also relied heavily on the development of underground gas storage fields in order to create reserve buffers.

Figure 2.1: Share of home heating fuel by energy source in Illinois, 1940 - 2020



Source: For 1940-2000, U.S. Census Bureau, Historical Census of Housing Tables (House Heating Fuel); for 2010 and 2020, U.S. Census Bureau, American Community Survey, 5-year data. https://www.census.gov/data/tables/time-series/dec/coh-fuels.html.

This massive expansion of pipeline infrastructure—both within and across states—was made possible by innovations in pipe rolling, metallurgy, and welding and joining pipes that occurred after World War II.[15] These advances improved pipeline reliability and led to a construction boom that extended into the 1960s, during which thousands of miles of pipeline were constructed. As long-distance transmission became possible, the commodity cost of natural gas dropped, making the fuel cost competitive with the local coal industry and enabling its continued capture of the coal industry's market share for home heating.

The fact that methane gas could now be transported long distances spurred innovation of new uses

14 Coal was eventually mined in 76 of the state's 102 counties.
15 "History," NaturalGas.org, http://naturalgas.org/overview/history/.

for gas, eventually encompassing space heating, manufacturing, cooling, refrigeration, and even electric power generation. In addition, household appliances—water heaters, ovens, cooktops, and furnaces—were converted to gas: "The expanded transportation infrastructure had made natural gas easy to obtain, and it was becoming an increasingly popular energy choice."[16]

D. Regulatory oversight

In 1913, the Illinois Commerce Commission (ICC) was established to regulate the nascent gas industry, in response to prevailing issues of corruption, price gouging, and insufficient safety protocols within public services.[17] The creation of this body was a key component of the Progressive Era's efforts to protect the public interest. Through its oversight, the ICC aimed to address and rectify the industry's early challenges, including collusion and counterproductive competition evidenced by the construction of unnecessary duplicate gas lines. By categorizing the gas industry as a public utility, the Commission endeavored to emulate competitive market benefits under a regulated framework, thereby ensuring the industry's alignment with public utility standards and safeguarding consumer interests.

Under the ICC's regulation, utilities could expand their gas networks as they saw fit, but would need the Commission's permission to set and charge rates to recover their costs through rate cases under what's known as cost-of-service ratemaking. In addition to regulating system expansion and subsequent cost recovery, the ICC in concert with the federal government instituted safety compliance measures, since the methane that flows through the pipeline network is highly combustible.

16 Ibid.

17 In 1913, the General Assembly replaced the Railroad and Warehouse Commission with a 5-member State Public Utilities Commision that had authority over the railroads and any investor-owned public utility in the state. In 1921, the General Assembly enacted the Public Utilities Act which transferred the PUC's powers to the newly created and independent agency named the Illinois Commerce Commission. https://www.icc.illinois.gov/home/centennial#:~:text=1921,named%20the%20Illinois%20Commerce%20Commission.

E. Expansion and saturation

Within this state regulatory structure, Illinois' four largest investor-owned gas utilities have thrived, expanding to serve 97 percent of gas customers in the state today,[18] with most of that expansion occurring from 1950 to 1970. During this dynamic post-war period, the state's population expanded 28 percent, from just shy of 9 million people in 1950 to over 11 million in 1970.[19] The dramatic expansion of the gas system was driven by the low cost of gas, the fact that methane gas was a superior heating fuel to manufactured coal gas,[20] and ambitious marketing by the gas industry. The industry's pro-gas campaign positioned "modern" gas furnaces and stoves as offering superior functionality, performance, and comfort compared to legacy coal furnaces.[21]

During this period of growth, the costs of the gas network expansion were more than offset by the additional revenue stream from new customers. In other words, spreading the construction costs of new lines over an expanding customer base made financial sense, based on the logic that the new customers added to the system would eventually share in reducing the high fixed costs of the gas system. The limitations to the expansion of pipeline gas networks were realized by the 1980s when new pipeline installations began to level off, having branched to nearly every urban and suburban neighborhood in the state, thus achieving "market saturation." Beginning in the 2000s, the rate of pipeline additions slowed dramatically.[22]

18 This customer count excludes municipally and cooperatively owned gas utilities in Illinois, for which there is no statewide public reporting.

19 "Illinois Population Data," Illinois Dept. of Public Health, https://dph.illinois.gov/data-statistics/vital-statistics/illinois-population-data.html

20 Fossil gas has two times more heat energy per cubic foot than coal gas, meaning that it is a superior heating fuel. (Werner Troesken, "The Institutional Antecedents of State Utility Regulation: The Chicago Gas Industry, 1860 to 1913" in *The Regulated Economy: A Historical Approach to Political Economy*, edited by Claudia Dale Goldin and Gary D. Libecap, 55–80. A National Bureau of Economic Research Project Report (Chicago: UP Chicago, 1994), https:// www.nber.org/system/files/chapters/c6572/c6572.pdf), p. 25.

21 Peoples Gas Light and Coke Company, *100 Years of Gas Service in Chicago, 1850-1950* (1950, Chicago), https://babel.hathitrust.org/cgi/pt?id=uiuo.ark:/13960/t4th8n800&seq=2.

22 GWD analysis of PHMSA data, PHMSA, Gas Distribution Annual Data: 2010 to present (ZIP extracted for 2022), https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

> **"In this nearly saturated, "post-expansion" phase of the gas industry, average delivery costs per customer necessarily increase due to the continued need for costly re-investments to replace aging gas infrastructure."**

This apparent exhaustion of new service opportunities must be understood within the context of a "history of service denial in some lower-income and rural communities, where gas service may be viewed as a hard-won right."[23] As demonstrated by Chicago's gas expansion and the neglect of service extension to less profitable, lower-income customers, access to energy is always uneven. Today, a utility's statutory "obligation to serve" is intended to protect this access, although it does not guarantee universal service.[24] It is also important to recognize that many who now have access to gas service may have difficulty affording it (see Section 2.H for more on energy affordability issues in Illinois).

In this nearly saturated, "post-expansion" phase of the gas industry, average delivery costs per customer necessarily increase due to the continued need for costly re-investments to replace aging gas infrastructure. These capital expenditures and the associated rate increases needed to fund them are likely to be a key driver of customer departures from the gas system towards technologies that are more efficient, increasingly cost effective, and that provide features that customers value, such as greater comfort, improved control, and cooling.

F. Drivers of policy change supporting the energy transition

Across the country, policymakers at the local, state, and federal levels have put in place a wide range of policies that are spurring the energy transition away from methane gas and toward clean energy alternatives (for a summary of the state policies enacted in Illinois, see Figure 2.2).

These policies have a number of objectives including:

- Reducing and permanently eliminating greenhouse gas (GHG) emissions for climate and health reasons
- Promoting equity and addressing long-standing environmental justice concerns
- Promoting adoption of clean energy technologies

23 Ted Lamm and Ethan N. Elkind, *Building Toward Decarbonization: Policy Solutions to Accelerate Building Electrification in High-Priority Communities*, Center for Law, Energy, and the Environment, Berkeley Law., p. 21, https://www.law.berkeley.edu/research/clee/research/climate/climate-change-and-business-research-initiative/setting-priorities-for-building-decarbonization/.

24 See BDC's report for more information on this dynamic: Kristin George Bagdanov, *Decarbonizing the Obligation to Serve,* Building Decarbonization Coalition (March 2024), https://buildingdecarb.org/wp-content/uploads/FINAL_Decarbonizing-the-Obligation-to-Serve_March2024.pdf.

> **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."**
>
> — ICC, 2023 Rate Case Order for Ameren

Figure 2.2: Illinois energy transition legislation and orders: Clean and Equitable Jobs Act[25] and Executive Order 2019-06

- **Economy-wide 100% clean energy by 2050**[26] (CEJA) and a commitment to reduce GHG emissions in line with 2015 Paris Climate Conference targets[27] (E.O. 2019-06).
- **Electric sector decarbonization** by 2045 and phaseout of electricity generated by coal and methane gas[28] (CEJA).
- Commitment to **40% renewable energy by 2030 and 50% by 2040** (CEJA).
- **1 million electric vehicles by 2030** (CEJA).
- **Beneficial electrification plans** to be developed by two largest electric utilities to support adoption of EVs, heat pumps, and other electric technologies (CEJA).
- Development of **tariff on-bill financing program** to enable widespread beneficial electrification (Equitable Energy Upgrade Program [EEUP]).[29]
- **Study on low-income discount energy rates**. CEJA directed the ICC to perform a study of the energy affordability and energy burdens of low-income gas and electric customers with a view to advising on options for tariffs to establish a new low-income discount rate structure that supports the state's clean energy goals and policies. The study was completed in 2022 (CEJA).[30]
- **Energy efficiency support for low-income households**: Utilities are to spend 15% of their income-qualified energy efficiency program budgets on health and safety measures that previously would have prevented efficiency investments in many low-income households (e.g., wiring issues, mold). In addition, a minimum of 80% of low-income or income-qualified efficiency spending must be spent on whole-building retrofits (CEJA).[31]

25 Public Act 102-0662, https://www.ilga.gov/legislation/publicacts/102/PDF/102-0662.pdf. For a summary, see https://www2.illinois.gov/IISNews/23893-Climate_and_Equitable_Jobs_Act.pdf. Other key features of CEJA include: expansion of IL's Renewable Portfolio Standard, subsidies for three nuclear plants, just transition programs for coal mine and power plant workers, payment of prevailing wages on nearly all non-residential wind and solar projects, new workforce development and just transition funds and programs, and a Coal-to-Solar Program that provides incentives to install energy storage at the sites of former coal plants. In addition, CEJA provides a number of consumer protections including for low-income utility residential customers, and moves electrical utilities to performance-based ratemaking.

26 Electrify Illinois: Illinois Commitment, "CEJA and Climate Action," https://ev.illinois.gov/illinois-commitment/ceja-and-climate-action.html.

27 Executive Order 2019-06 (January 23, 2019), https://www.illinois.gov/government/executive-orders/executive-order.executive-order-number-6.2019.html

28 CEJA mandates phased retirement or adoption of emission-free technologies for all fossil-fuel fired electrical plants in the State. Private natural gas-fired generators emitting NOx and SO2 above certain thresholds and operate within 3 miles of an environmental justice community must reduce their emissions or phase out by 2030. Others have until 2045. For the state's 13 remaining coal-fired plants, the phaseout ranges from 2030 to 2045. The goal under the law is complete power sector decarbonization by 2045. For more detail, see: https://www.pjm.com/-/media/committees-groups/committees/oc/2021/20211202/20211202-item-16-update-on-illinois-clean-energy-jobs-act.ashx.

29 Illinois Equitable Energy Upgrade Program (EEUP), https://icc.illinois.gov/informal-processes/Equitable-Energy-Upgrade-Plan.

30 Illinois Commerce Commission, Bureau of Public Utilities, *Low-Income Discount Rate Study Report to the Illinois General Assembly*, (December 2022), 8, https://icc.illinois.gov/downloads/public/icc-reports/low-income-discount-rate-study-report-2022-12-15.pdf.

31 Laura Goldberg, "The Unsung Hero of Illinois' Climate Law: Energy Efficiency" (October 6, 2021, NRDC Expert Blog), https://www.nrdc.org/bio/laura-goldberg/unsung-hero-illinois-climate-law-energy-efficiency.

Figure 2.3: Illinois Commerce Commission (ICC) energy transition-related rulings, 2023-24

- **"Future of Gas" proceeding** initiated in March 2024.[32] The Commission stated that the "gas distribution system must change" in order to align with the state's economy-wide 2050 clean energy goal. The proceeding will explore the decarbonization of the gas system and develop recommendations for regulatory actions and legislation.[33]
- **Long-Term Gas Infrastructure Plan** by gas utilities required on biennial basis beginning in 2025. For the first time, gas utilities will be required to publicly disclose a 5-year action plan of investments with a longer-term planning horizon where applicable, describing the lowest societal cost gas distribution investments necessary to meet customer demand and comply with public policy objectives.[34]
- **Low-income discount rate for gas** to be implemented by October 2024 for eligible customers with incomes up to 300% of the Federal Poverty Level. This subsidy is to be funded by the rest of the existing customer base via slightly higher rates.
- **Rate case actions:** Dubbed a "regulatory earthquake" by consumer advocates in Illinois,[35] the ICC significantly reduced the rate increases requested by the Big Four gas utilities in Illinois, disallowing substantial amounts of capital requests: $101.12 million to Peoples (25% less than requested); $5.57 million to North Shore (34% less than requested);[36] $96.99 million to Nicor Gas (30.3% less than requested); and $36.34 million to Ameren (50.8% less than requested). While the utilities still secured substantial rate increases, the ICC sent a strong message of tightened regulatory oversight.
- **Peoples System Modernization Program (SMP) paused:** The ICC ordered Peoples to pause spending on its SMP until the ICC has a proceeding to determine the optimal method for replacing aging gas infrastructure and a prudent investment level. The new proceeding was initiated on January 31, 2024.

32 ICC, "Initiation of proceeding to examine the Future of Natural Gas and issues associated with decarbonization of the gas distribution system," Order, Docket 24-0158 (March 7, 2024), https://www.icc.illinois.gov/docket/P2024-0158/documents.
33 The proceeding begins with two workshop series. See: https://www.icc.illinois.gov/programs/Future-of-Gas-Workshop.
34 Illinois Commerce Commission, 2023 Rate Case Order for Ameren, Docket 23-0067 (November 16, 2023), p. 96, https://www.icc.illinois.gov/docket/P2023-0067/documents/344282/files/601209.pdf.
35 Adams, Andrew. "Advocates Hail Regulatory 'Earthquake' as State Slashes Requested Gas Rate Increases." *The State Journal-Register*, November 17, 2023. https://www.sj-r.com/story/business/energy-resource/2023/11/17/illinois-commerce-commission-regulators-cut-gas-rate-increase-requests/71616362007/.
36 Illinois.gov. "ICC Issues Decision on Peoples Gas and North Shore Gas' General Rate Increase Requests," November 16, 2023. https://ltgov.illinois.gov/news/press-release.27314.html.

For a century now, the public's understanding of methane gas has been largely shaped by the gas industry's depiction of gas as clean, cheap, and efficient. However, scientific research has advanced our understanding of the gas system's role in exacerbating climate change as well as its contribution to local pollution and health issues. Indeed, the magnitude of methane gas leakage may be so great that any climate benefits from using methane gas relative to coal are substantially eroded.[37]

A sizable proportion of Illinois' GHG emissions comes from the state's methane gas supply chain, either from leaked or combusted gas occurring across the gas distribution system or within buildings—from stoves, boilers, water heaters, and other end-uses—or from the midstream part of the system where leaks, venting and purging, and combustion occur. As will be explained in more detail in the next section, the state's dependence on methane gas for residential heating translates into high pipeline density—Illinois has the third most distribution pipes of any state. Two additional factors add to the amount of fossil fuel pollution that Illinois experiences: its unique "hub" role as a major crossroads for interstate fossil fuel transmission lines, and its downwind location from major fossil fuel extraction sites in other states.

As a result of all of these factors, Illinois experiences significant and widespread fossil fuel pollution. While it is difficult to quantify the magnitude of the damage because methane leakage from the gas system is historically underestimated by official federal and state estimates,[38] a recent study that included Chicago found official inventories underestimate gas-related methane emissions by 50 percent.[39] Methane leaks have been found to be concentrated in the metro region's low-income communities, producing "disturbing inequalities": leak density increases with both the percent of people of color in the census tract and decreasing income.[40] Nationwide, the Environmental Defense Fund estimates that "U.S. onshore gas pipeline methane leakage is between 3.75 times and 8 times greater than estimated by EPA."[41]

"Illinoisians' exposure to methane pollution comes at a high cost, and has been linked to an increase in respiratory ailments, including asthma, as well as premature death."

Illinoisians' exposure to methane pollution comes at a high cost, and has been linked to an increase in respiratory ailments, including asthma, as well as premature death. Modeling by RMI based on a 2021 study that quantifies the relationship between pollution in buildings and health[42] estimates that "In Illinois, air pollution from burning fuels in buildings led to an estimated 1,123 early deaths and $12.574 billion in health impact costs in 2017."[43] In addition to these broad health impacts, fossil fuels, especially indoor methane gas combustion, intensify respiratory illness:

- 21 percent of childhood asthma in Illinois is attributable to gas stove use, more than any other state in the nation and well above the

37 Deborah Gordon et al., "Evaluating net life-cycle greenhouse gas emissions intensities from gas and coal at varying methane leakage rates," *Environmental Research Letters* (July 2023, Vol. 18, No. 8), https://iopscience.iop.org/article/10.1088/1748-9326/ace3db.

38 For a review of the measurement problem, see Dorie Seavey, *Leaked and Combusted: Strategies for reducing the hidden costs of methane emissions and transitioning off gas* (March 2024, HEET), pp. 13-16, https://tinyurl.com/4dd9ru3d.

39 Cody Floerchinger et al., "Relative flux measurements of biogenic and natural gas-derived methane for seven U.S. cities," *Elementa Science of the Anthropocene* (February 2021, 9:1), https://doi.org/10.1525/elementa.2021.000119.

40 Zachary D. Weller et al., "Environmental injustices of leaks from urban natural gas distribution systems; Patterns among and within 13 U.S. metro areas," *Environmental Science & Technology* (2022, 56, 12), pp. 8599-8609, https://pubs.acs.org/doi/10.1021/acs.est.2c00097.

41 Renee McVay, Methane Emissions from U.S. Gas Pipeline Leaks (August 2023, Environmental Defense Fund), p. 6, https://www.edf.org/sites/default/files/documents/Pipeline%20Methane%20Leaks%20Report.pdf.

42 Jonathan J. Buonocore et al., "A decade of the U.S. energy mix transitioning away from coal: historical reconstruction of the reductions in the public health burden of energy," *Environmental Research Letters* (2021, 16), https://iopscience.iop.org/article/10.1088/1748-9326/abe74c.

43 RMI, " What is the Health Impact of Buildings in Your State?" https://rmi.org/health-air-quality-impacts-of-buildings-emissions#IL.

national average of 12.7 percent.[44] This reflects the high reliance of Illinois households on gas for cooking.[45]

- Because of its upwind location relative to major fossil fuel producers in other states, Illinois ranks seventh in the U.S. for total deaths attributable to oil and gas pollution, eighth for asthma, and twelfth for VOC and NOx emissions.[46]

The health burdens of methane pollution are extensive and uneven. This "social cost" of methane has not been adequately considered in cost-benefit analyses of maintaining the gas system or transitioning to renewable and non-emitting energy systems.

The EPA's most recent estimates of the social cost of carbon emissions do not include the costs of these detrimental health impacts, yet even so, applied to the 32 million metric tons of carbon dioxide generated by Illinois' total gas use, they yield an estimated *annual* social cost of $6.7 billion for 2024.[47] Incorporating the EPA's conservative estimate of a 1 percent methane leakage rate from the gas distribution system,[48] the additional social cost of methane emissions adds a further $624 million in annual impact. This latter cost may actually be several orders of magnitude higher since methane emissions have been found to be significantly underestimated.[49] Added together,

> **"Illinois' methane gas use results in an annual social cost of $7.3 billion per the U.S. EPA's latest GHG damage estimates."**

these two estimates indicate that Illinois' methane gas use results in an annual social cost of $7.3 billion per the U.S. EPA's latest GHG damage estimates. Whether viewed from a social cost or social benefit perspective, it is clear that including these considerations would dramatically alter traditional benefit-cost calculations.

In addition to the goal of reducing and eliminating GHGs, Illinois, along with several other states, has instituted policies that prioritize environmental justice and energy affordability, seeking to rectify many decades of a disproportionate burden on low-income communities. These policies are in part the result of decades of dedicated work by community-based organizations and advocates who have elevated these concerns and conditions. For example, Blacks In Green, an environmental justice organization dedicated to systemic change for Black communities, led the charge with fellow members of the Illinois Clean Jobs Coalition to pass CEJA, one of the most equity-focused climate bills in the U.S. This continued pressure and advocacy has helped move Illinois toward a clean energy future that is more just and equitable. However, energy inequity persists throughout the state and must be addressed:

- Roughly two-thirds of the state's households live in the immediate seven-county Chicago metro area, and this area has the second highest energy-burdened population in the U.S. (second

44 Taylor Gruenwald et al., "Population attributable fraction of gas stoves and childhood asthma in the United States," *International Journal of Environmental Research & Public Health* (2023, Vol. 20, No. 1), https://doi.org/10.3390/ijerph20010075.

45 Gas stoves have been found to leak significant amounts of methane even when they are turned off. When turned on, the burning of the gas produces carbon dioxide but also a number of compounds that are harmful to human health. Research has established that these health-damaging pollutants constitute a major source of air pollution within homes. For a review of this research, see Dorie Seavey, *Leaked and Combusted: Strategies for reducing the hidden costs of methane emissions and transitioning off gas* (March 2024, HEET), p. 18, https://tinyurl.com/4dd9ru3d.

46 Jonathan J. Buonocore et al., "Air pollution and health impacts of oil & gas production in the United States," *Environmental Research: Health* (2023, 1), p. 11, https://doi.org/10.1088/2752-5309/acc886.

47 The EPA defines the social cost of GHG emissions as the monetary harm to society from emitting a metric ton of a GHG into the atmosphere in a given year. It measures the value of all future climate change impacts. U.S. EPA, *EPA Report on the Social Cost of Greenhouse Gases* (November 2023), https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf. For a calculator, see: Institute for Policy Integrity, NY University School of Law, "Calculating the Social Cost of Greenhouse Gases" (based on EPA 2023 estimates using a 2% discount rate), https://costofcarbon.org/calculator.

48 U.S. EPA, Emission Factors for Greenhouse Gas Inventories (last modified: February 13, 2024), Table 1, https://www.epa.gov/system/files/documents/2024-02/ghg-emission-factors-hub-2024.xlsx.

49 Based on its review of recent peer-reviewed research using extensive field survey campaigns of pipeline infrastructure across the U.S., the Environmental Defense Fund (EDF) estimates that U.S. onshore gas pipeline methane leakage is between 3.75 times and 8 times greater than estimated by EPA. Renee McVay, *Methane Emissions from U.S. Gas Pipeline Leaks* (August 2023, Environmental Defense Fund), p. 6, https://www.edf.org/sites/default/files/documents/Pipeline%20Methane%20Leaks%20Report.pdf.

only to New York City).[50] Energy burden refers to the percent of household income spent on energy bills. A household that spends more than 6 percent of its income on home energy bills has a "high energy burden."[51]

- Nearly one in four Illinois households are energy insecure, meaning that they forego paying for food or medicine in order to pay an energy bill, keep their homes at unsafe or unhealthy temperatures, are unable to use their heating or air conditioning equipment because it is broken and they cannot afford to fix it, or have received disconnection or delivery stop notices.[52]
- 30 percent of Chicago census tracts are designated environmental justice (EJ) neighborhoods[53] and one-third of Chicago households are low income.[54]
- High numbers of Illinois gas and electricity ratepayers are behind on their bills and are assessed late fees.[55]

The state has begun to address these concerns by giving the ICC the authority to require utilities to establish discounted gas and electric rates for low-income ratepayers. CEJA also directs the ICC to establish a planning process to institute "tariff on-bill financing," a mechanism that seeks to remedy the disparities in access to capital by adding energy efficiency upgrades incrementally to a household's utility bills (see Figure 2.2).

"As the State embarks on a journey toward a 100 percent clean energy economy, the gas system's operations will not continue to exist in its current form."

Finally, though CEJA directs specific attention to decarbonizing the state's electricity and transportation sector, the ICC notes that "the Act is silent as it relates to the gas system."[56] In particular, the state lacks targeted goals for decarbonizing its gas-dependent building sector, a critical part of the state's transition away from its reliance on methane gas for heating and cooking. A 2021 report by Elevate Energy and RMI found that, given the large carbon footprint of Illinois' buildings sector, achieving the Paris Climate Agreement commitments would not be possible unless methane gas was phased out of buildings.[57] Governor Pritzker has stated that Illinois should "explore decarbonizing the way we heat our homes and businesses."[58] And ICC Chairman Doug Scott agrees that a sea change is needed: "As the State embarks on a journey toward a 100 percent clean energy economy, the gas system's operations will not continue to exist in its current form. Identifying how our gas and electric systems can adapt to meet these goals, and what specific actions should be taken to achieve them, will be an important task for the Commission moving forward."[59]

Illinois must continue to align its climate and equity goals with its long-term energy system

50 Ariel Brehobl, Lauren Ross, and Roxana Ayala, *How High Are Household Energy Burdens: An Assessment of National and Metropolitan Energy Burden across the United States*, American Council for an Energy-Efficient Economy (ACEEE) (September 2020), Table B3.2, p. 57, https://www.aceee.org/sites/default/files/pdfs/u2006.pdf.

51 Illinois Commerce Commission, Bureau of Public Utilities, *Low-Income Discount Rate Study Report to the Illinois General Assembly* (December 2022), p. 20.

52 U.S. Energy Information Administration, 2020 RECS Survey Data, "Highlights for household characteristics of U.S. homes by state, 2020," https://www.eia.gov/consumption/residential/data/2020/state/pdf/State%20Household%20Characteristics.pdf.

53 Chicago Department of Health, Chicago Health Atlas, https://chicagohealthatlas.org/indicators/CHAIXYP?topic=chicago-environmental-justice-index.

54 U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Low-Income Energy Affordability Data - LEAD Tool - 2020 Update, https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool.

55 During 2023, Peoples and Nicor assessed late fees each month for an average 28 percent and 20 percent of their residential customers, respectively. As of the end of January 2024, residential arrearages totaled $83.7 million for Peoples, $64.6 million for Nicor, and $23.2 million for Ameren. Illinois Commerce Commission, Credit, Collections, and Arrearages Reports Monthly Dashboard, https://www.icc.illinois.gov/industry-reports/credit-collections-and-arrearages-reports/monthly-dashboard.

56 ICC, Final Order in the 2023 Rate Case for Ameren, Docket 23-0066), p. 93, https://www.icc.illinois.gov/docket/P2023-0067/documents/344282/files/601209.pdf.

57 Louise Sharrow et al., Building Electrification Helps Illinois Achieve Climate Goals, RMI (September 2020) https://rmi.org/insight/building-electrification-helps-illinois.

58 Governor J.B. Pritzker, "Make natural gas utilities more accountable to customers and the state," Chicago Sun Times (March 8, 2023), https://chicago.suntimes.com/2023/3/8/23631191/natural-gas-utilities-illinois-commerce-commission-ceja-prices-rate-increases.

59 Illinois Commerce Commission, Press Release (November 16, 2023), https://ltgov.illinois.gov/news/press-release.27313.html.

planning, including creating sector-specific goals for decarbonization, programs that allocate clean energy benefits and enable households of all incomes to access new technologies, and long-term gas planning proceedings that commit gas utilities to emissions reductions and clean energy infrastructure.

G. Competing technologies

Like previous transitions, a major threat to the gas distribution system is the emergence of superior alternatives to the status quo, including heat pump space heating and cooling systems, heat pump water heaters, and induction stoves. Complementary incentives at the local, state, and federal level are also helping to encourage greater energy efficiency and fuel switching from gas to electric equipment.

Advancements in technologies beyond end-user appliances—such as improvements in clean generation, storage, and transmission—also serve to erode the competitiveness of the methane gas. Additionally, the current transition is also relying on deep energy efficiency and demand flexibility (i.e., advanced controls that enable demand management and bidirectional energy transfers). Both of these approaches are critical for reducing energy demand and limiting the scale of the required supply-side buildout of electrical generation and transmission. The end goal is more efficient and grid-interactive buildings.

Below, we highlight several key technologies that are displacing the demand for pipeline gas.

Air-source heat pumps

Air-source heat pumps (ASHPs) enable customers to disconnect from the gas system and utilize electricity for both heating and cooling. ASHPs improve household comfort and, for some homes, are the first time the home is outfitted with cooling technology.[60] Historically reserved for milder climates, the adoption of ASHPs is also growing in colder climates as the technology improves and consumer awareness increases. These improvements, combined with government incentive programs, have significantly increased ASHP adoption in recent years. In 2022, heat pump sales outpaced gas furnace sales in the United States for the first time.[61] Federal agencies and state and local governments continue to support ASHP adoption, most notably through the federal Inflation Reduction Act. Currently, limiting factors include ease of installation, cost, and performance in cold climates. Improvements in any of these categories will accelerate adoption.

Ground-source heat pumps

Compared to ASHPs, ground-source heat pumps (GSHPs) operate via a thermal exchange from the ground or other thermal energy sources, rather than the air, which improves efficiency. For geothermal applications, GSHPs are more costly to install, but are a compelling alternative in dense areas and colder climates where shared heat sources can be utilized, and geothermal bore holes can be optimized to reduce individual customer costs. The primary cost drivers of a geothermal system are the cost and complexity of drilling.[62] Electric consumption of GSHPs is also less than that of similarly sized ASHPs, which can mitigate impacts to the electric distribution grid, avoid the need for costly system upgrades, and reduce operational costs for building owners.[63] Finally, GSHPs can be used in hybrid and networked configurations. In a hybrid configuration, overall system efficiency can be improved, similar to hybrid heating with non-pipeline fuels. Hybrid GSHP systems can also be used to heat domestic water. In a networked configuration, per-household drilling costs can be reduced and spread across a wider base of

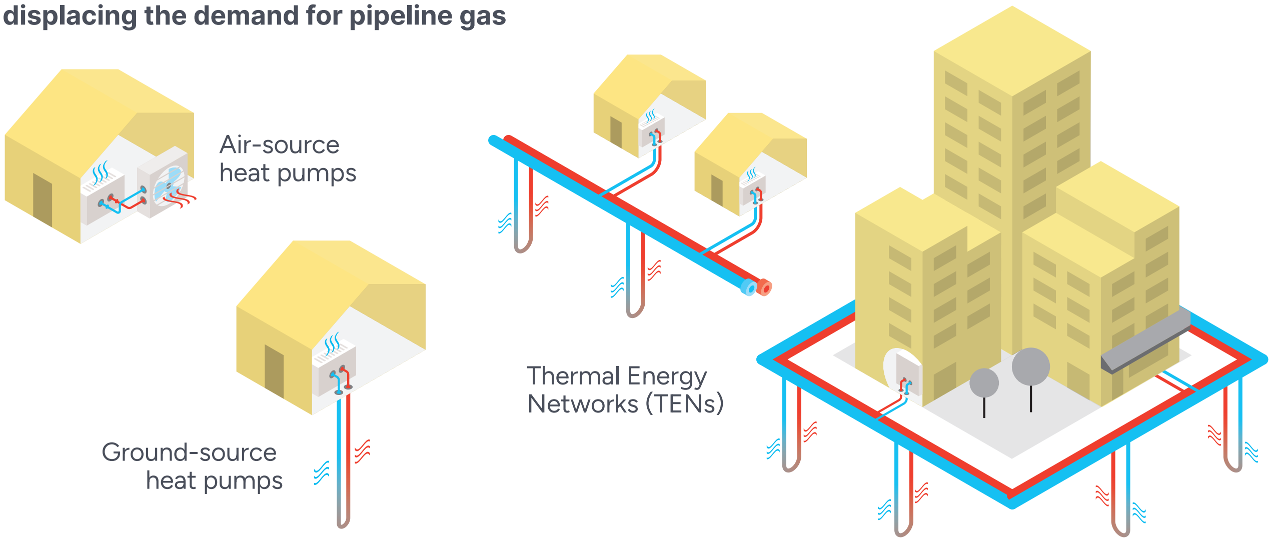
60 Julian Spector, "10 Questions to Ask If You Want to Get a Heat Pump," Canary Media (February 7, 2023), https://www.canarymedia.com/articles/heat-pumps/10-questions-to-ask-if-you-want-to-get-a-heat-pump.

61 Maria Virginia Olano, "Chart: Americans Bought More Heat Pumps than Gas Last Year," Canary Media (February 10, 2023), https://www.canarymedia.com/articles/heat-pumps/chart-americans-bought-more-heat-pumps-than-gas-furnaces-last-year.

62 "Choosing and Installing a Geothermal Heat Pump System," Energy.gov. https://www.energy.gov/energysaver/choosing-and-installing-geo-thermal-heat-pump-system

63 Mike Henchen et al., "Clean Energy 101: Geothermal Heat Pumps," RMI (March 29, 2023), https://rmi.org/clean-energy-101-geother-mal-heat-pumps/.

Figures 2.2: Competing technologies that are displacing the demand for pipeline gas



customers. Such an implementation falls into a broader category called thermal energy networks.

Thermal Energy Networks (TENs)

Thermal energy networks refer to neighborhood-scale interconnections of underground pipes carrying and sharing thermal energy between connected buildings. The connected ambient loops can harness thermal reservoirs, such as the temperature of bedrock or local bodies of water, and waste heat from data centers or wastewater treatment facilities. GSHP networks powered by electricity can provide highly efficient heating and cooling along with multiple social and economic benefits.[64] Networked systems of GSHPs are one way to implement a TEN, but TENs can also distribute heating and cooling from a central plant to the connected buildings. Multiple utility-owned TENs demonstration projects are under development in New York and Massachusetts.[65] Blacks in Green is also actively investigating a community-owned project for Chicago's West Woodlawn neighborhood.[66] Finally, TENs can be designed to expand over time to serve entire neighborhoods and municipalities, which expands the opportunity for balancing the network as different buildings use heating and cooling in different ways.

The technologies and innovations listed above are just some of the examples for how clean energy infrastructure can outperform gas equipment in terms of comfort, efficiency, emissions, and health. Continuing to invest in this market of innovation through directive incentives and programs is essential to ensuring that these clean energy benefits are accessible to everyone.

H. Illinois on the brink of a new energy transition

The energy transition in Illinois is unfolding as the result of ongoing technological change and innovation, significant policy change dedicated to lowering GHG emissions, and unprecedented federal and state incentives. Consumer preferences are changing too, as awareness of the need to decarbonize grows and there is a better understanding of the importance to health and safety of cleaner space and heating technologies.

Every gas territory in Illinois can expect, and needs to plan for, a significant decline in gas consumption over the coming decades. For example, a recent

64 Kristin George Bagdanov, Claire Halbrook, and Amy Rider, *Neighborhood Scale: The Future of Building Decarbonization*, Building Decarbonization Coalition and Gridworks (December 2023), https://buildingdecarb.org/resource/neighborhoodscale.

65 "UpgradeNY Calls For The New York Public Service Commission To Advance Utility Thermal Energy Network Project Proposals," Upgradeny, https://www.upgradeny.org/statement-on-uten-project-proposals and "Networked Geothermal: The National Picture, " HEET, https://www.heet.org/blog-items/networked-geothermal-the-national-picture.

66 Juanpablo Ramirez-Franco, "A Geothermal Energy Boom Could Be Coming to Chicago's South Side," Grist (February 23, 2024), https://grist.org/cities/black-communities-south-side-chicago-geothermal-heat/.

study by the Electric Power Research Institute (EPRI) projects a decrease in gas consumption in the Ameren gas territory of 18 percent to 40 percent by 2050 due to electrification. Specifically within the building sector, EPRI projects a decline in gas consumption of 38 percent to 56 percent by 2050 due to gains in market share for both residential heat pump space heating and heat pump water heating.[67]

Coal and gas electrical generation are being phased out by state policy under CEJA. In terms of Illinois' residential building sector, the share of gas in home heating peaked in the 1980s and held steady through the 1990s.[68] Beginning in 2010, the market share of gas in home heating began to decline and has fallen every year since (from 81 percent in 2010 to 76 percent in 2022, or by 5 percentage points). During the same period, homes heated by electricity have increased each year, up from 13 percent to 18 percent over the same period.[69] At the same time, as of 2020, the pace of heat pump adoption in Illinois was still slow.[70] A tremendous opportunity exists, however, since in the Midwest, more than a third of households report having old HVAC equipment, and the housing stock in general is older and prime for efficiency and weatherization upgrades. A recent RMI study focusing on the Midwestern cities of Columbus and Minneapolis, along with five other cities, finds that all-electric homes are less expensive to construct than new mixed-fuel homes, even in cold climates.[71]

As Illinois lays the foundation for an energy transition that involves transitioning off gas and adopting new space and water heating technologies for buildings, there are lessons to be gleaned from the history of the state's prior energy transitions:

- How people heat and light their homes is more dynamic than it appears to be: multiple energy transitions have occurred in Illinois over the past two centuries.
- These transitions have sometimes required significant adjustments by households, businesses, and investors. Households had to switch out their stoves to accommodate Bunsen burners and then methane gas. Streets in Chicago are still paving over sub-street coal chutes used to pour coal directly into the basement of buildings to be used for furnaces.
- With each transition, a tipping point occurred where the price of the ascending fuel fell and remained below that of the declining fuel, thus securing a price advantage that resulted in strictly lower operational costs for the equipment and appliances based on the new technology. In addition, the ascendant energy offered greater energy efficiency, greater safety, and less pollution. Identical dynamics are driving today's transition.

While there are important similarities with prior transitions, the current transition brings some unique demands and opportunities. First, unlike prior transitions, which took place over generations, there is great scientific urgency for Illinois to significantly reduce its GHG emissions. Second, unprecedented financial incentives and subsidies have been provided by the public sector to galvanize the uptake of newer technologies and seed market transformation. Finally, the need for coordination and management of this energy transition is without parallel. Without integrated planning across different energy sectors, supply chain development, and the creation of unified platforms to provide building upgrade services, the cost of the transition will likely be orders of magnitude higher than necessary.

Currently, the most significant "unmanaged" cost threatening Illinois' transition is the expense of maintaining the existing gas distribution system. We turn now to an exploration of the contemporary role of gas in the state's economy and provide an in-depth analysis of the state's four largest gas utilities.

67 ICC, Ameren 2023 Rate Case, ICC Docket 23-0067, PIO 7.04R Attach 1, Electric Power Research Institute, "Electrification Scenarios for Ameren Illinois' Energy Future," Executive Summary, p. 11.

68 U.S. Decennial Census, Historical Census of Housing Tables: House Heating Fuel, https://www.census.gov/data/tables/time-series/dec/coh-fuels.html.

69 U.S. Census Bureau, American Community Survey, ACS 5-year, Table S2504, https://data.census.gov/table/ACSST1Y2022.S2504?q=S2504&g=040XX00US17_160XX00US1714000.

70 Katherine Shok, "Electrifying the Midwest" (October 17, 2023), https://atlasbuildingshub.com/2023/10/17/electrifying-the-midwest.

71 Claire McKenna, Amar Shah, and Leah Louis-Prescott, *The New Economics of Electrifying Buildings: An Analysis of Seven Cities, RMI* (2020), https://rmi.org/insight/the-new-economics-of-electrifying-buildings.

Section 3

The Gas System Today

A. Key takeaways

- Illinois is deeply dependent on methane gas. Only two states (UT and CA) have a greater reliance on gas for residential use. Approximately one in four Illinois households rely on gas for their primary heating fuel; in Chicago, roughly 80 percent rely on gas. Households in the state consume 41 percent more gas than the national average. The density of gas infrastructure in the state mirrors this heavy reliance: Illinois ranks third in the country for total miles of distribution mains.
- Virtually all methane gas consumed in Illinois is imported from other states where it is drilled or fracked and then piped under pressure through thousands of miles of gathering and transmission lines.
- The "Big Four" investor-owned utilities in Illinois are Ameren, Nicor, North Shore, and Peoples. These companies serve over 97 percent of the state's gas customers.
- From 2014 to 2022, the Big Four accelerated their gas system capital spending, investing over $9 billion and increasing their total gas plant by 84 percent, from $11.8 billion to $21.7 billion.[72] This substantial spending, which includes guaranteed rates of return, is to be recovered from gas ratepayers over the "useful lives" of the assets, i.e., the next 40-70 years.
- More than a third of the existing distribution system (21,000 miles of mains) is more than 50 years old and, therefore, in need of near-term replacement. Maintaining Illinois' gas system means committing to successive, costly waves of capital spending to replace aging cohorts of gas mains and services.
- The future of gas in Illinois is expensive: In this post-expansion era of the gas industry, during which gas customers and throughput have stabilized, gas pipeline replacements will be spread over a stagnant, instead of growing, customer base, resulting in a sharply rising average delivery costs and therefore rates.

B. Introduction

Illinois is one of America's top methane gas states. It is the eighth largest gas-consuming state, with 75 percent of households using methane gas to heat their homes.[73] Additionally, it ranks third in the country for the total number of miles of distribution mains, an infrastructure density that reflects this heavy reliance. But where does the state's gas come from, and how is it used across the state's economy?

72 Gas plant refers to a gas utility's distribution mains, meters, and services; transmission mains; storage facilities, and other structures, property, and equipment. In this report we also refer to these components as "gas infrastructure."

73 EIA, Illinois State Profile and Energy Estimates, Profile Analysis (August 17, 2023), https://www.eia.gov/state/analysis.php?sid=IL#100 and EIA, Illinois Quick Facts, https://www.eia.gov/state/print.php?sid=IL.

Having a clear understanding of the gas system's structure and infrastructure is essential to ensure that clean energy policies and regulations target the best leverage points to achieve widespread, lasting, and equitable impacts.

This section examines how gas flows through and shapes nearly every sector of Illinois' economy. We present a brief overview of the structure and regulation of the gas industry in Illinois, including how customers pay for gas and how utility costs are recovered. We turn next to the Big Four gas utilities that are the main focus of this report: Ameren, Nicor, North Shore and Peoples. We lay out the unique geographic territory of these companies, their diverse gas assets and customer base, and their recent trends in capital spending.

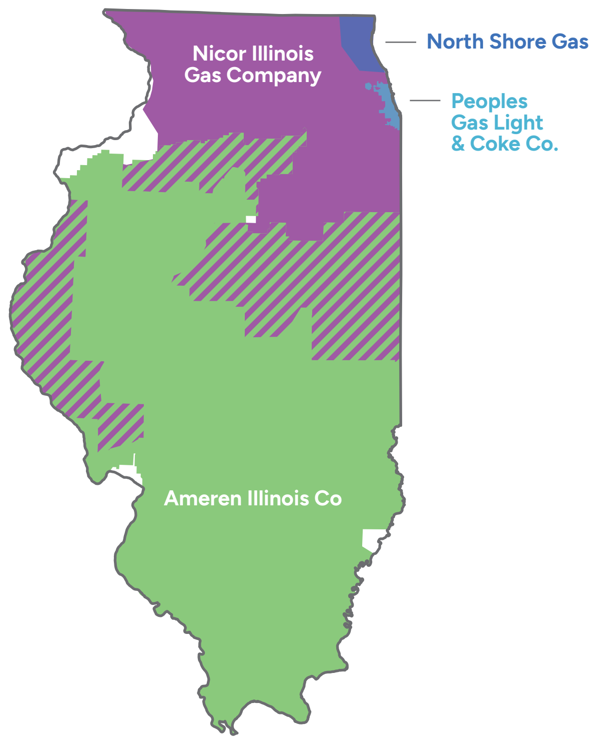
C. Industry structure

There are over 70 operators in the state, but the four largest investor-owned utilities—Ameren, Nicor, North Shore, and Peoples—together serve four million customers, or 97 percent of the state's gas users, and are therefore the focus of this report. Together these four companies own and operate 94 percent of Illinois' gas distribution mains.[74]

Besides the Big Four, there are five other for-profit, investor-owned utilities that operate in the state. In addition, some customers get their gas service from one of 65 municipal gas systems that are owned and operated by towns or other municipal jurisdictions. Finally, Illinois is home to two local cooperative gas utilities (member-owned not-for-profits) and four privately-owned utilities. Municipal gas systems and gas cooperatives are not subject to price regulation by the Illinois Commerce Commission but must comply with the state's Natural Gas Pipeline Safety Program and Regulations which are administered by the ICC.[75]

Illinois gas utilities take delivery of gas from interstate pipelines and use larger and higher-pressure intrastate transmission lines to move the gas either directly to delivery systems or to one of the state's 28 underground storage fields. Huge compressing stations receive the gas at reduced pressures, compress it to high pressure, then force it through transmission lines to various "city gates" that connect transmission pipelines to lower-pressure local distribution networks that bring gas directly to homes and businesses.

Figure 3.1: Introducing Illinois' "Big Four" investor-owned utilities



Source: Homeland Infrastructure Foundation-Level Database (HIFLD), "Natural Gas Service Territories," (last updated on Sept. 21, 2017). Ameren and Nicor territories are exclusive; however the data is reported at the county level, which gives the appearance of intersecting territories.

74 This calculation excludes municipally and cooperatively owned gas utilities for which there is no statewide public reporting.

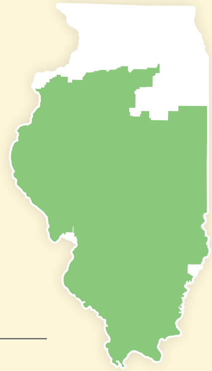
75 Illinois Commerce Commission, *2022 Annual Report on Electricity, Gas, Water and Sewer Utilities* (January 2023), https://www.icc.illinois.gov/downloads/public/en/2022%20Annual%20Report.pdf. For the Pipeline Safety Program, see https://www.icc.illinois.gov/home/illinois-gas-pipeline-safety-program.

Illinois Gas Utility

Ameren Illinois Co.

Parent company: Ameren Corporation

Ameren Illinois is a combination gas and electric utility whose service territory is located in central and southern Illinois. It provides gas service to 816,000 gas and 1.2 million electric customers across 1,200 communities and 43,700 square miles. The territory is divided into 4 regions (north, south, east, and west). The company was formed in 2010 as the result of the merger of 3 legacy utilities.



Gas infrastructure

17,456
miles of distribution mains

813,274
service lines

1,224
miles of transmission mains

12
underground storage fields

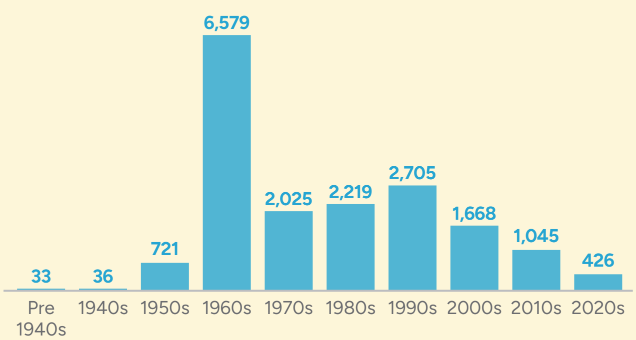
47
customers per mile of distribution main

$647,596
spend per mile of distribution main installed

Replacement priorities

- Mechanically coupled steel mains, replace @ 60-80 miles for 10 years
- Mechanically coupled steel services
- High-pressure transmission pipes (67 miles)
- Unprotected steel services
- Pressure control stations
- Pre-1970 pipeline (~6,500 miles)

Miles of distribution mains by decade installed



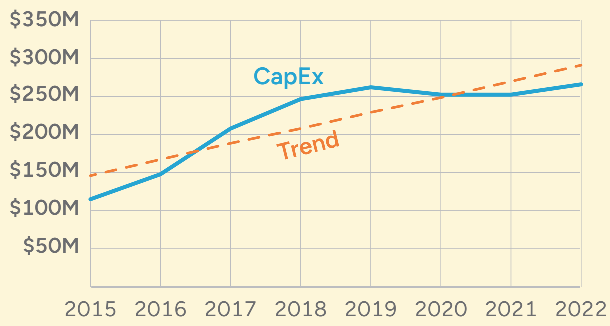
System growth

10%
average year-over-year trend growth in CapEx

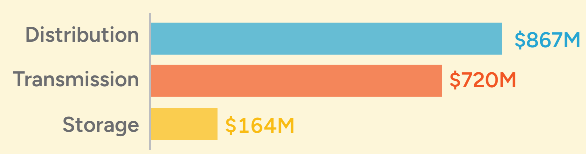
81%
increase in value of gas plant from 2014 to 2022

$265 million
gas system CapEx in 2022

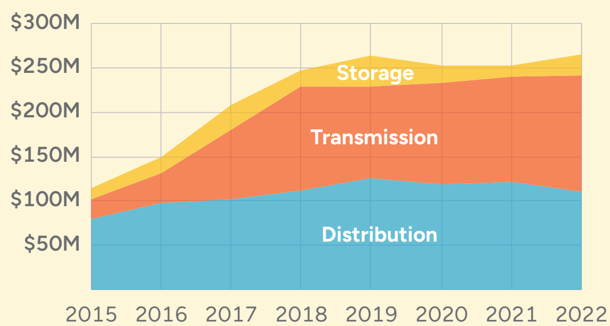
Annual CapEx, 2015-2022



Total spending by category from 2015 to 2022



Spending by category, 2015-2022



For sources and citations see page 99

Customers

3%
total growth, 2000-2022

0.12%
average annual growth, 2000-2022

813,757
total customers, 2022

744,995
residential customers, 2022

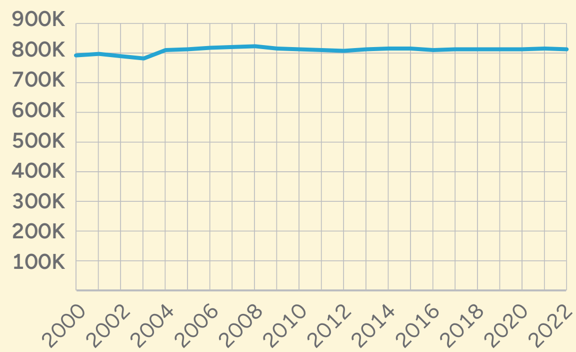
$630
estimated average annual delivery cost per customer in 2024

$7.3 million
total bill assistance received by Ameren from public programs and rate riders in 2021

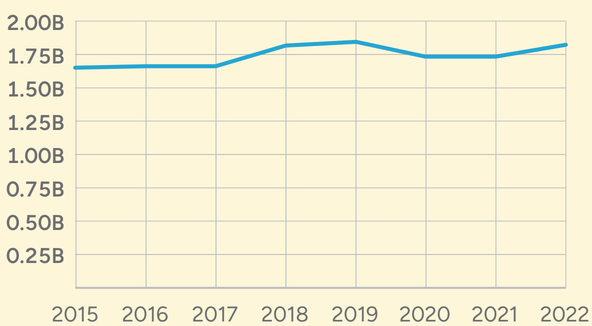
11%
residential customers charged late fees in January 2024

$23.2 million
total residential arrearages at end of January 2024

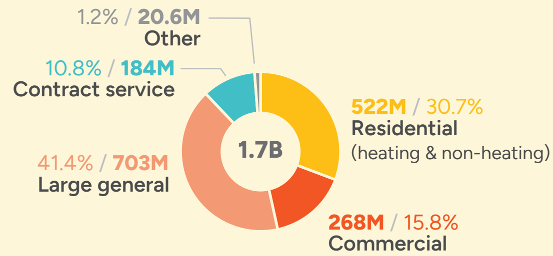
Total customers vs year



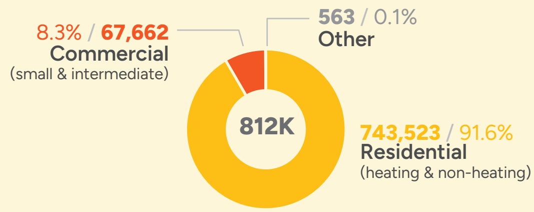
Total therms sold



Therms by customer type, 2024 test year



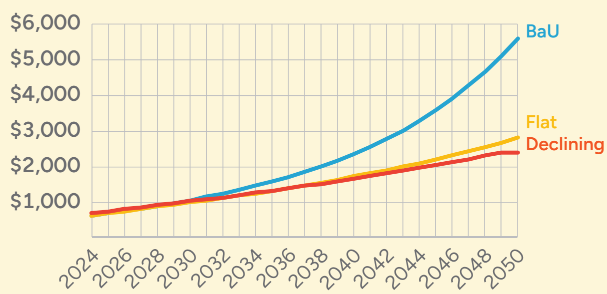
Customers by type, 2024 test year



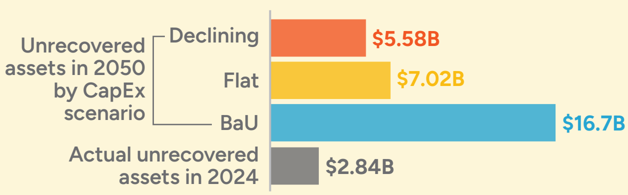
Cost projections & unrecovered gas assets

50% by 2030
revenue increase needed if business-as-usual (BaU) spending continues

Projected average annual delivery cost per customer by utility CapEx scenario



Projected unrecovered gas assets by utility CapEx scenario

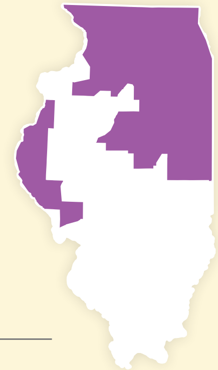


Illinois Gas Utility

Nicor Gas Company

Parent company: Southern Company

Nicor is Illinois' largest gas utility. It serves about 2.3 million customers in 650 communities across 17,000 miles in northern Illinois, outside Chicago, and along the Mississippi River.



Gas infrastructure

33,616
miles of distribution mains

2,054,463
service lines

1,164
miles of transmission mains

8
underground storage fields

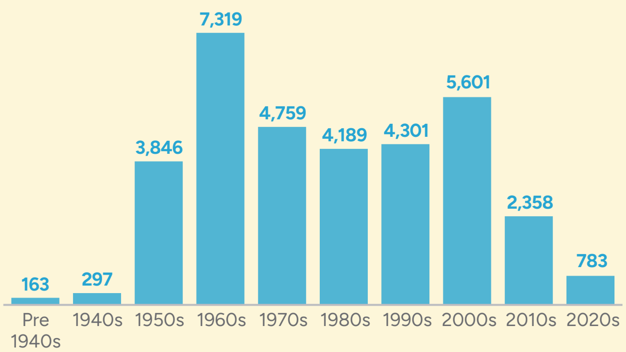
67
customers per mile of distribution main

$1,885,687
spend per mile of distribution main installed

Investment priorities

- Over 4,300 miles of pre-1960 non-bare steel mains
- 1,624 miles of pre-1960 mechanically-coupled steel mains
- 38,277 pre-1985 vintage plastic services
- 61 miles of transmission lines

Miles of distribution mains by decade installed



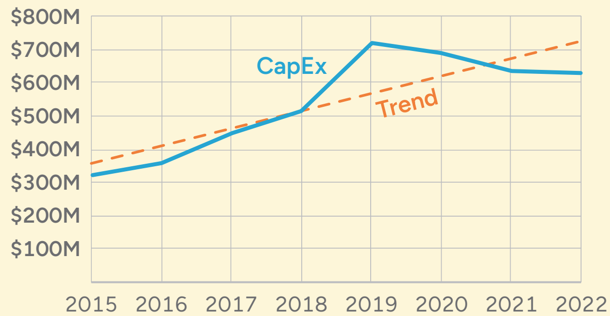
System growth

11%
average year-over-year trend growth in CapEx

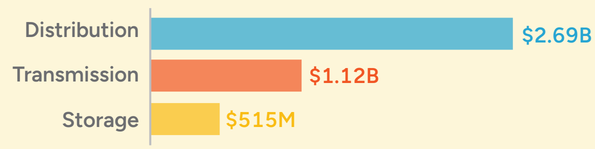
90%
increase in value of gas plant from 2014 to 2022

$629 million
gas system CapEx in 2022

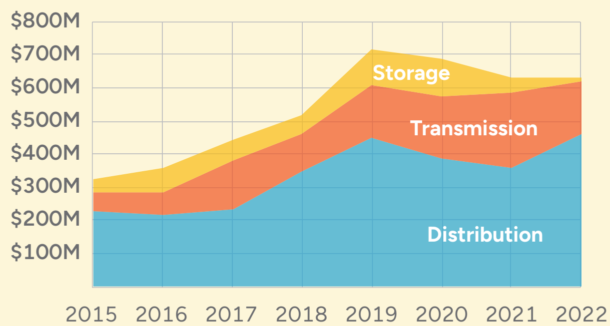
Annual CapEx, 2015-2022



Total spending by category from 2015 to 2022



Spending by category, 2015-2022



For sources and citations see page 99

Customers

15%
total growth, 2000-2022

0.64%
average annual growth, 2000-2022

2,259,019
total customers, 2022

1,898,579
residential customers, 2022

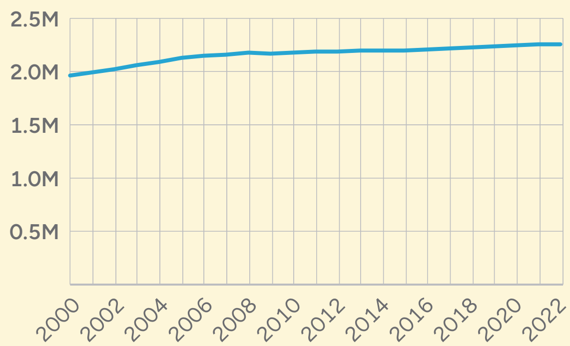
$453
estimated average annual delivery cost per customer in 2024

$60.1 million
total bill assistance received by Nicor from public programs and rate riders in 2021

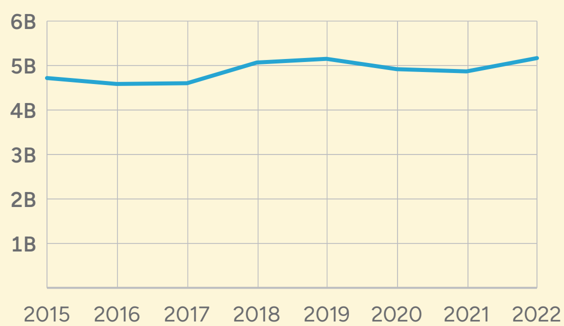
20%
residential customers charged late fees in January 2024

$64.6 million
total residential arrearages at end of January 2024

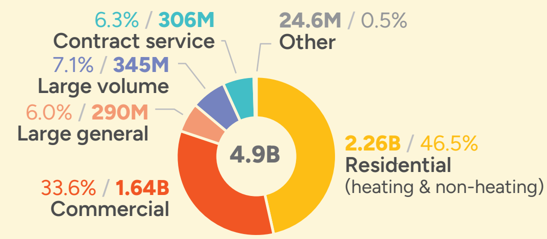
Total customers vs year



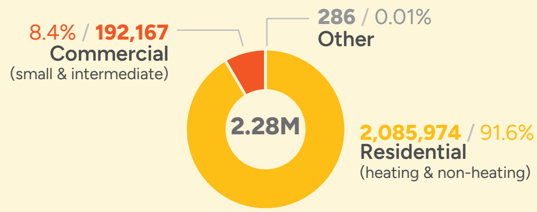
Total therms sold



Therms by customer type, 2024 test year



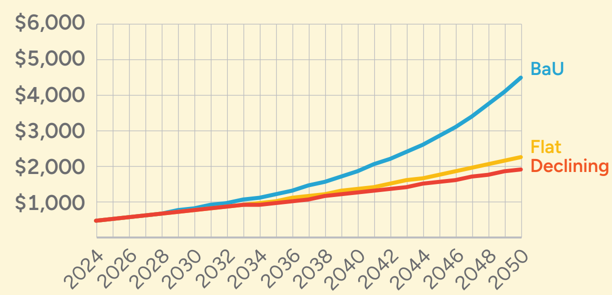
Customers by type, 2024 test year



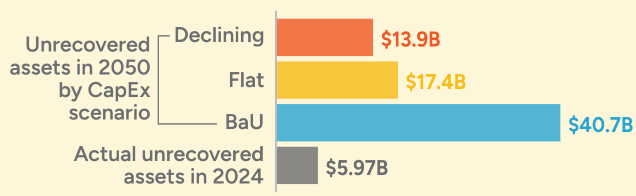
Cost projections & unrecovered gas assets

61% by 2030
revenue increase needed if business-as-usual (BaU) spending continues

Projected average annual delivery cost per customer by utility CapEx scenario



Projected unrecovered gas assets by utility CapEx scenario



Illinois Gas Utility

North Shore Gas

Parent company: WEC Energy Group

North Shore is the smallest of the four companies and serves about 160,000 customers in the northern suburbs of Chicago. This territory covers about 275 square miles and serves 54 communities.

Gas infrastructure

2,360
miles of distribution mains

143,473
service lines

68
miles of transmission mains

0
underground storage fields

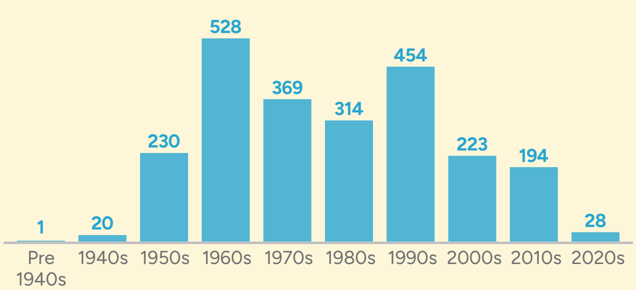
69
customers per mile of distribution main

N/A
spend per mile of distribution main installed

Replacement priorities

- Reconfirm 17.5 miles of transmission mains by 2035 (some may be replaced)
- Replace vaporizers, piping, and other facilities at propane peaker plant
- Upgrade 2 of 6 stations feeding distribution system
- Install advanced metering throughout territory
- No announced plan for 778 miles of pre-1970 distribution mains

Miles of distribution mains by decade installed



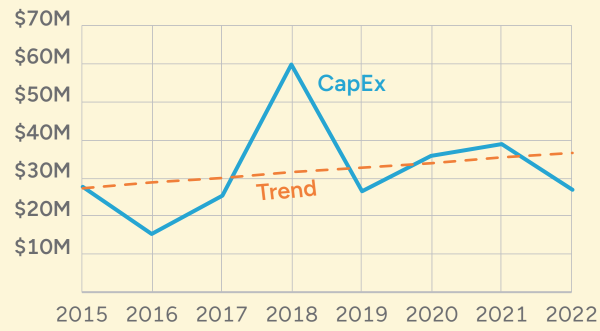
System growth

4%
average year-over-year trend growth in CapEx

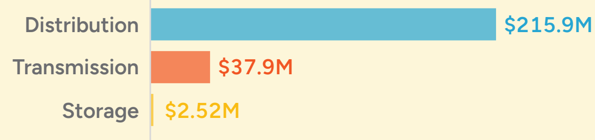
55%
increase in value of gas plant from 2014 to 2022

$27 million
gas system CapEx in 2022

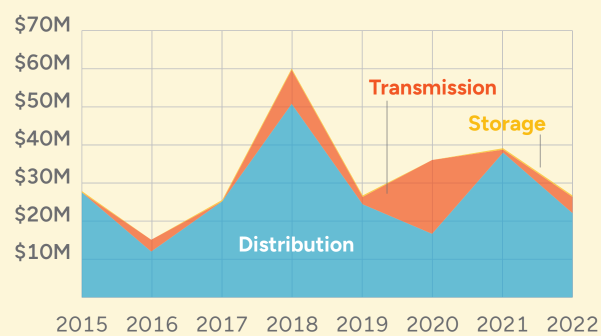
Annual CapEx, 2015-2022



Total spending by category from 2015 to 2022



Spending by category, 2015-2022



For sources and citations see page 99

Customers

10%
total growth, 2000-2022

0.44%
average annual growth, 2000-2022

163,984
total customers, 2022

140,710
residential customers, 2022

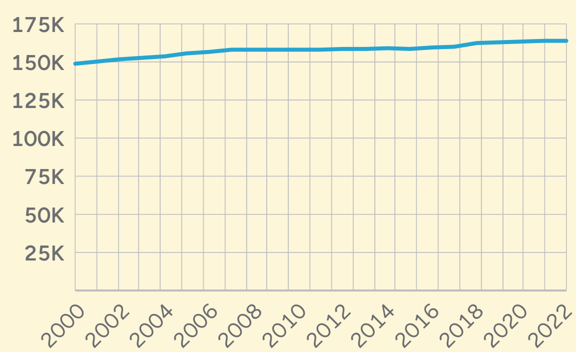
$595
estimated average annual delivery cost per customer in 2024

$5.9 million
total bill assistance received by North Shore from public programs and rate riders in 2021

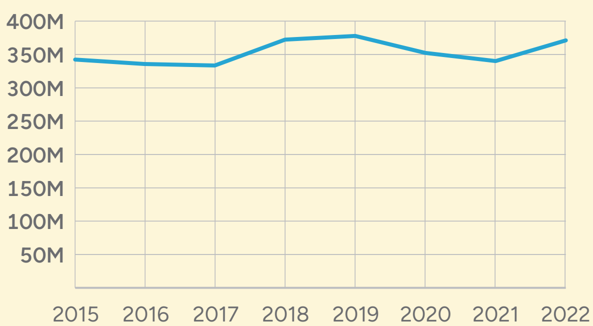
17%
residential customers charged late fees in January 2024

$2.3 million
total residential arrearages at end of January 2024

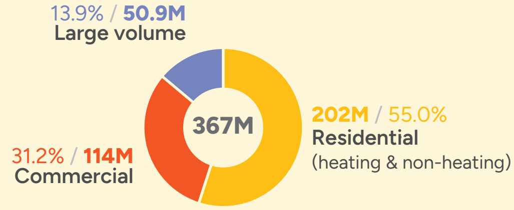
Total customers vs year



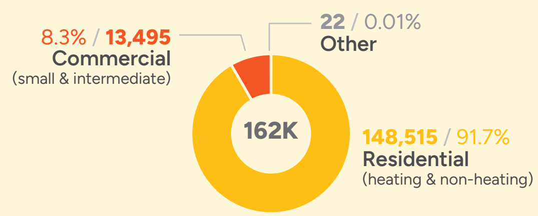
Total therms sold



Therms by customer type, 2024 test year



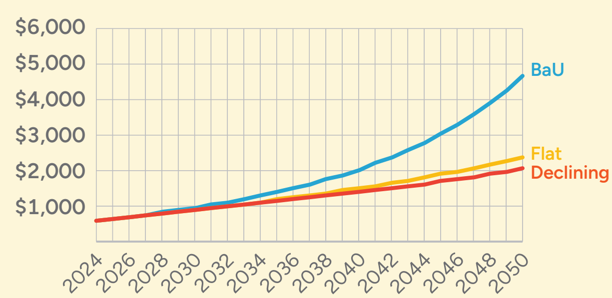
Customers by type, 2024 test year



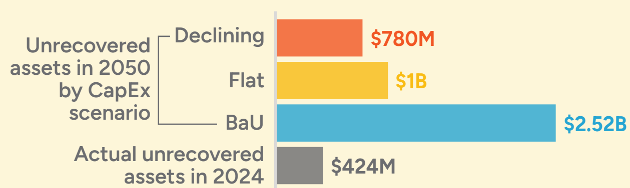
Cost projections & unrecovered gas assets

44% by 2030
revenue increase needed if business-as-usual (BaU) spending continues

Projected average annual delivery cost per customer by utility CapEx scenario



Projected unrecovered gas assets by utility CapEx scenario

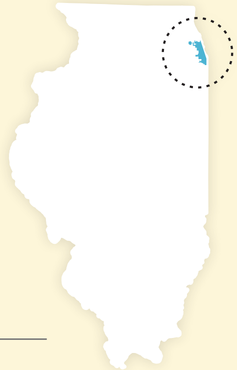


Illinois Gas Utility

Peoples Gas Light & Coke Co.

Parent company: WEC Energy Group

Peoples Gas serves the city of Chicago (a 237 square mile area) and has 873,000 customers. Peoples was chartered in 1855 and was the second utility to begin serving gas in Chicago, following Chicago Gas Light & Coke Company in 1849.



Gas infrastructure

4,678
miles of distribution mains

499,354
service lines

346
miles of transmission mains

1
underground storage field

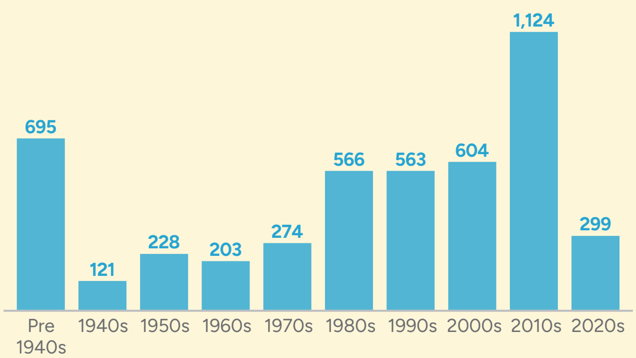
188
customers per mile of distribution main

$1.2M - $2.8M
spend per mile of distribution main installed

Replacement priorities

- Replace an additional 1,500 mains and related services and meters by 2040
- Modernize South Shop facility for providing operations, maintenance, and construction
- Install advanced metering throughout territory
- Major upgrade of customer service technology
- Modernize data and voice communications infrastructure

Miles of distribution mains by decade installed



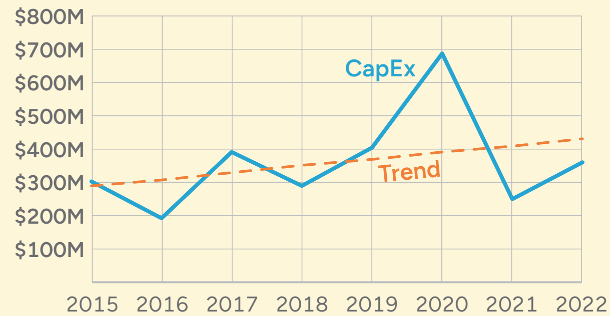
System growth

6%
average year-over-year trend growth in CapEx

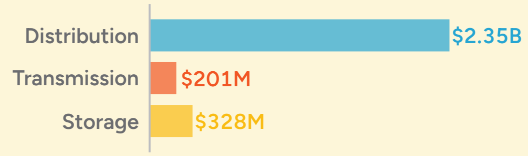
80%
increase in value of gas plant from 2014 to 2022

$363 million
gas system CapEx in 2022

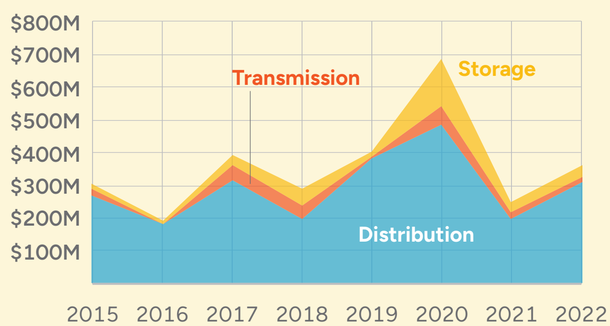
Annual CapEx, 2015-2022



Total spending by category from 2015 to 2022



Spending by category, 2015-2022



For sources and citations see page 99

Customers

10%
total growth, 2000-2022

0.43%
average annual growth, 2000-2022

880,236
total customers, 2022

765,607
residential customers, 2022

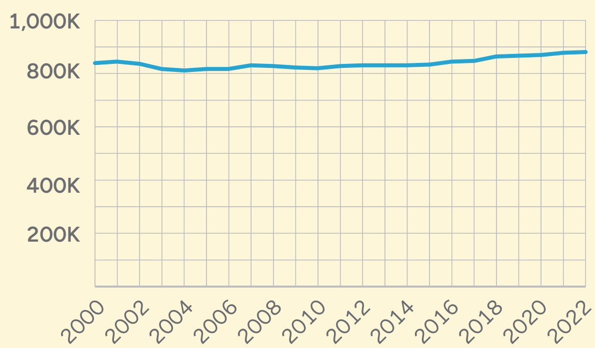
$994
estimated average annual delivery cost per customer in 2024

$76 million
total bill assistance received by Peoples from public programs and rate riders in 2021

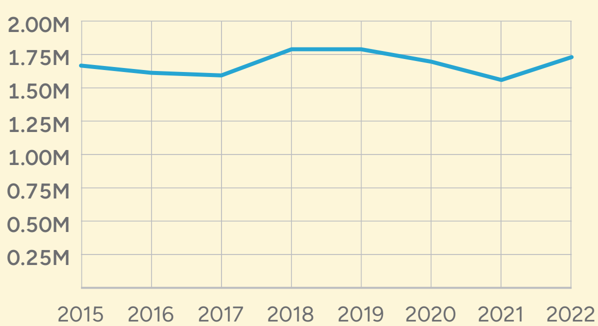
29%
residential customers charged late fees in January 2024

$83.7 million
total residential arrearages at end of January 2024

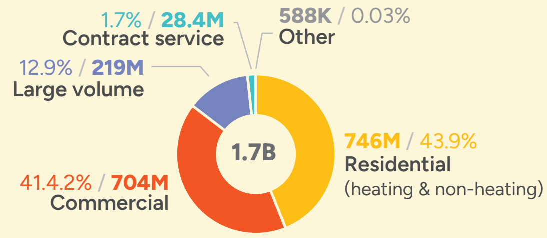
Total customers vs year



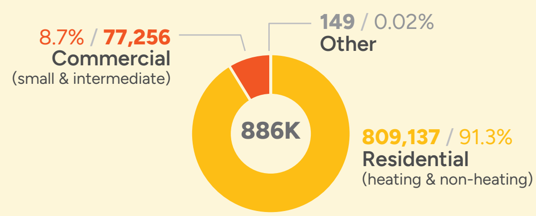
Total therms sold



Therms by customer type, 2024 test year



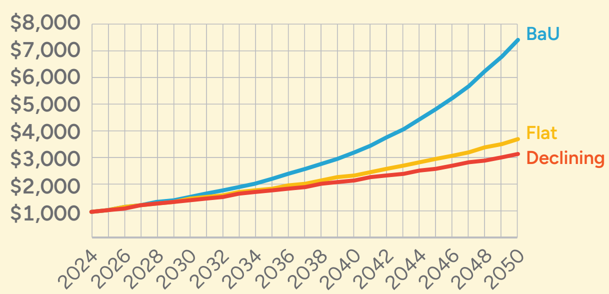
Customers by type, 2024 test year



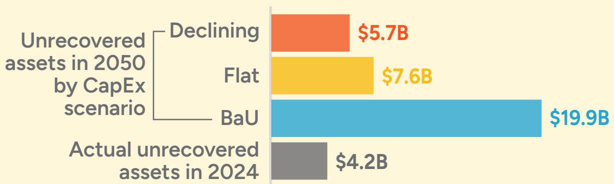
Cost projections & unrecovered gas assets

37% by 2030
revenue increase needed if business-as-usual (BaU) spending continues

Projected average annual delivery cost per customer by utility CapEx scenario



Projected unrecovered gas assets by utility CapEx scenario



D. How gas is used and consumed across the Illinois economy

About 1,100 trillion Btus of gas are currently consumed in Illinois each year, more than any other fossil fuel.[76] Illinois is the eighth largest gas consuming state in the country. Figure 3.2 allows us to follow the movement of gas through the economy.

Imports and exports

Starting at the left side of the diagram, we see that Illinois imports all of its gas from three adjacent states (Iowa, Indiana, and Missouri). Those states in turn receive methane gas from Canada, the Gulf Coast, the Rockies Express Pipelines, and the Marcellus and Utica shale formations. Additionally, slightly more than half of the gas entering Illinois is "exported" via interstate pipelines to the east through Indiana, to the north via Wisconsin, and to the south through Missouri. These exports underscore Illinois' significant national role as a key transportation hub for gas.

The remaining gas is transported via intrastate transmission networks either directly to electricity generation or to either the storage or distribution systems of one of Illinois' four largest gas utilities—Nicor, Ameren, Peoples, and North Shore, as indicated in the center of the diagram. Illinois relies heavily on methane gas storage[77] (not pictured in this diagram). There are 28 active underground storage sites in 24 counties with a storage capacity of just over 1 trillion cubic feet.[78] These sites are used to maintain inventory in order to provide supply flexibility and to mitigate the risk associated with seasonal price movements.

76 U.S. Energy Information Agency, State Profile and Energy Estimates for Illinois, released June 23, 2023, https://www.eia.gov/state/seds/seds-data-complete.php?sid=IL#Consumption.

77 Illinois has the largest amount of methane gas storage capacity in saline aquifer formations in the nation.

78 U.S. EIA, Underground Natural Gas Storage Capacity, Total Number of Existing Fields and Total Storage Capacity, Annual, 2016-21.

Gas consumption by sector

After reaching the transmission lines of the Big Four, gas is sold to four distinct types of customers: electric power generation, residential, industrial, and commercial.[79] In 2021, the breakdown of total gas consumption by sector was:

- Residential: 36 percent
- Industrial: 23 percent
- Commercial: 21 percent
- Electrical generation: 20 percent

Gas consumption by end use

The right-most section of the diagram breaks down final end-use consumption of gas. The biggest end-use is space and water heating for residences and businesses at 54 percent of total statewide gas use. The next largest use is for industrial processes (23 percent), which includes ammonia production. Illinois has several major ammonia plants and related nitrogen facilities that use gas as a feedstock to manufacture synthetic fertilizers.[80]

Zooming in on residential consumption

A close look at residential consumption of gas in Illinois reveals the very high proportion of households that use gas for some end-use (84 percent) (see Figure 3.3). Only two states have a higher dependence on gas: Utah and California. Nearly 60 percent of the state's residential gas consumption is for home heating[81] and 75 percent of homes rely on gas for their primary heating fuel.[82]

Illinois households consume 41 percent more gas than the national average. As shown in Figure 3.4, Illinois also outpaces many of its Midwest neighbors.

79 A very small amount of gas is delivered to vehicle fuel consumers.

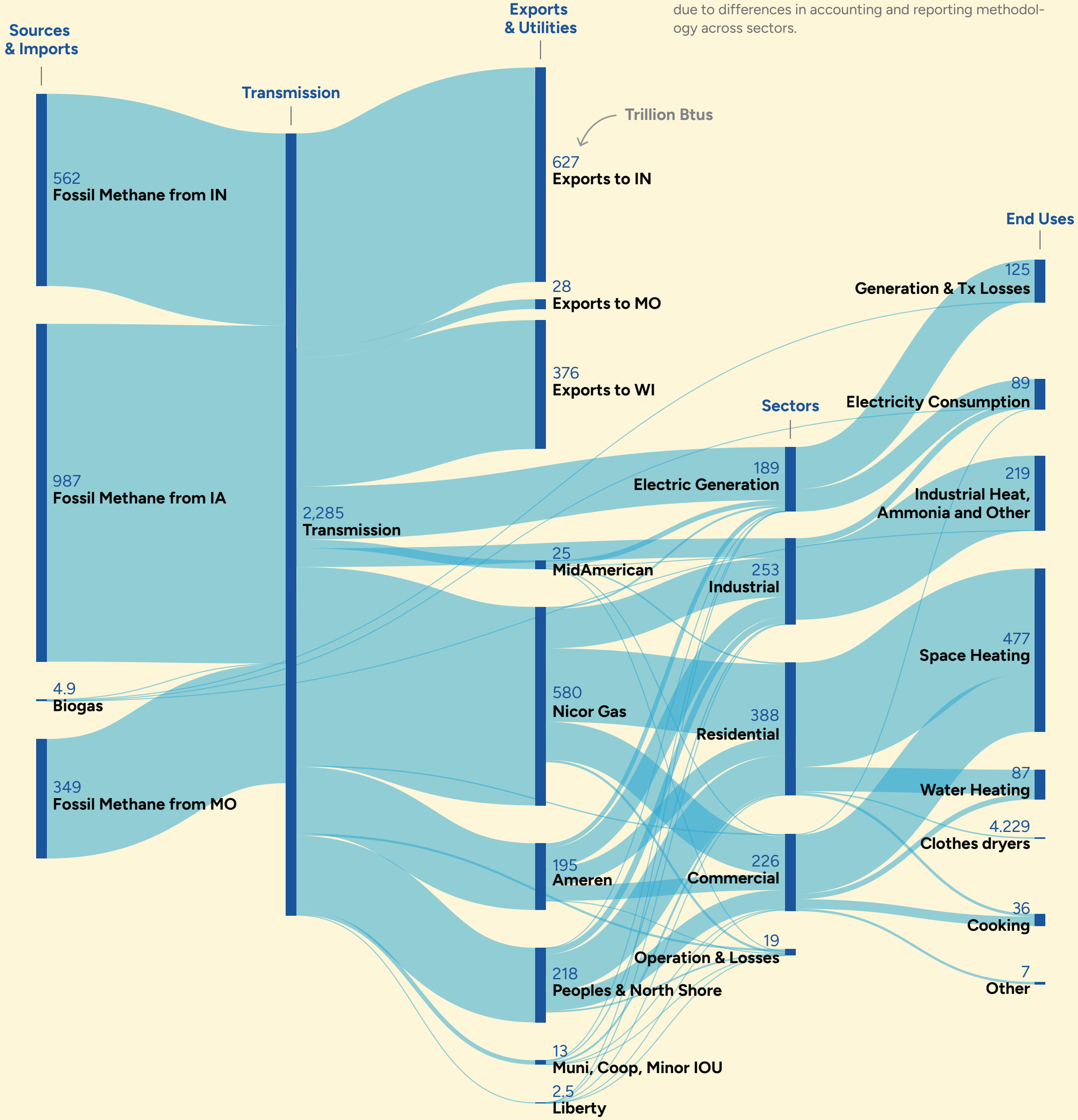
80 One of the largest facilities is LyondellBassell's Morris Site, an integrated petrochemical facility located 60 miles from Chicago. The site is one of the few petrochemical facilities in the Midwest and uses natural gas liquids as a feedstock for manufacturing plastics, chemicals, and refining petrochemicals.

81 U.S, EIA, 2020 RECS Survey Data, CE3.1ST Annual household site end-use consumption in United States homes by state - totals and averages, 2020, https://www.eia.gov/consumption/residential/data/2020/state/pdf/ce3.1.st.pdf.

82 U.S. EIA, Illinois State Energy Profile (last updated on August 17, 2023), https://www.eia.gov/state/print.php?sid=IL.

Figure 3.2: **How methane gas flows through the Illinois economy: Sankey diagram mapping gas sources and uses**

Source: Groundwork Data calculations using 2021 data from: U.S. Energy Information Administration Forms 176, 860, 923; CBECS; RECS; EPA AgStar Database; EPA Landfill Methane Outreach Program Database, USGS Mineral Yearbook. Values should be considered approximate due to differences in accounting and reporting methodology across sectors.



In general, Midwest states use more gas than other parts of the country (34 percent more), likely reflecting the region's "older, less energy efficient building stock, a dependence on gas infrastructure, and a cold climate."[83]

Regional variations

There are important regional variations in residential gas usage in Illinois:[84]

- Roughly two-thirds of the state's households reside in the immediate seven-county Chicago metro area consisting of the city of Chicago, the rest of Cook County, and then the counties of DuPage, Kane, Kendall, Lake, McHenry and Will. In Chicago, approximately 80 percent of households rely on gas and in the seven-country area, 84 percent do.[85] This gas territory is served by Peoples, North Shore, and Nicor.
- The non-metro remainder of northern Illinois (Nicor territory) has slightly lower reliance on gas: roughly 76 percent of households rely on gas, 16 percent on electricity, and 8 percent on bottled gas (propane).
- Finally, in the central and southern parts of the state (Ameren gas territory), reliance on utility gas falls to roughly 60 percent of households.[86] The share of households heated by electricity more or less doubles from the northern part of the state to 30 percent and bottled gas (propane) is used as a home heating fuel in roughly 10 percent of households. This same lower-gas reliance profile also applies to the four-county easternmost part of the state that borders Missouri. Nicor has a strong presence in those counties.

Illinois is deeply dependent on its gas system. Not only is the sheer volume of gas traveling through the state huge but, in the most densely populated parts of the state, nearly 80 percent of households rely on gas for space heating. Fugitive gas leaks from transmission and distribution pipelines, storage facilities, processing stations, and even inside homes add to the ill effects of emissions from gas combustion. The next two sections describe the current regulatory environment for managing gas utilities, setting rates, and determining cost recovery.

E. Pipeline safety, hazards, and emissions

Illinois' vast network of pipelines and related gas facilities delivers a fuel that powers much of the state's economy. But gas is also a fuel accompanied by public safety and hazard risks due to its explosive potential.[87] In addition, as reviewed in Section 2.F, methane has climate- and health-damaging consequences when it is leaked and combusted.

The main approach of the gas industry to addressing these public safety risks has been to replace pipelines, no matter what the cost and not necessarily with clear protocols that prioritize the riskiest pipes or the pipes with the largest leak volumes. In its 2023 rate case orders, the ICC pushed the state's gas utilities to move beyond a generalized appeal to "safety and reliability" when it wrote in each decision: "The question is not whether pipeline replacements generally improve safety and reliability, but what types of pipes are to be replaced, to what degree safety and reliability are affected, at what pace, and at what cost."[88]

83 Atlas Buildings Hub, Residential Building Characteristics Dashboard, 2020.
84 This section relies on calculations by Groundworks Data using numbers available at https://www.energy.gov/scep/slsc/lead-tool to approximate county-level aggregations corresponding to the relevant gas territories.
85 Ibid. Figures obtained from LEAD Tool. Chicago is served by Peoples; North Shore is based in Lake County and also serves a small portion of Cook County. Nicor serves the remaining counties but also parts of Lake County and Cook County.
86 Some of these households may be served by muni gas companies rather than Ameren.

87 For a listing of gas incident investigations in Illinois, see public reporting by the ICC Illinois Gas Pipeline Safety Program available at https://www.icc.illinois.gov/home/illinois-gas-pipeline-safety-program/incident-investigations. In 2023, 12 incidents were reported, all occurring in the Ameren and Nicor territories. Structures appear to have been damaged or destroyed in the explosions occurring in Granite City, Lisle, Oakpark, Rockford, and Woodstock.
88 ICC, Ameren Illinois Company, Order, Docket P2023-0067 (November 16, 2023), p. 90.

Figure 3.3: Percentage of households within each state that use methane gas for any end use (2020)

Source: U.S. EIA, "Today in Energy," (March 23, 2023)

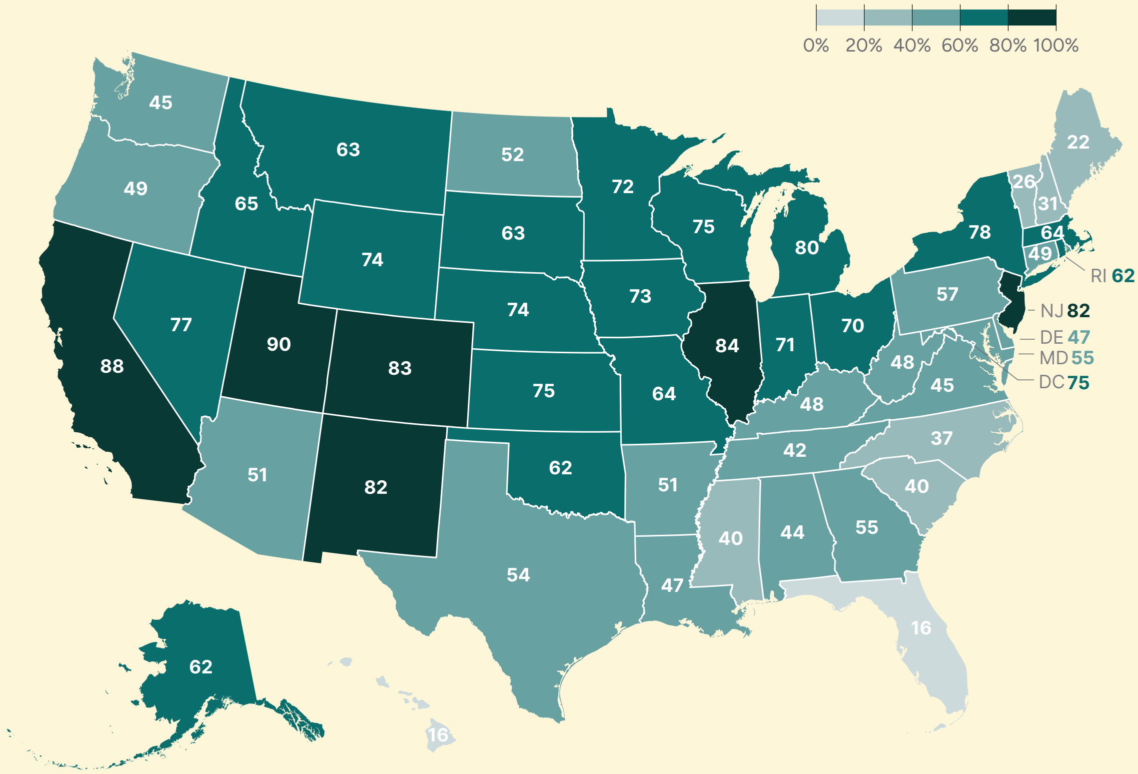
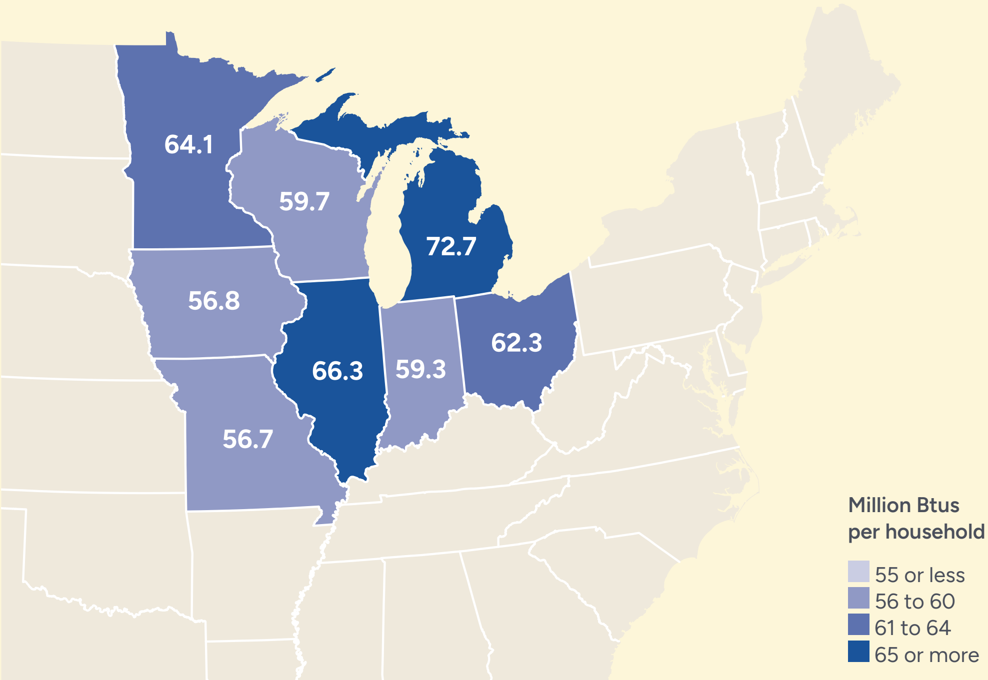


Figure 3.4: Methane gas consumption for space heating, U.S. Midwest (2020)

Source: U.S. EIA, "Today in Energy," (Aug. 7, 2023)



Existing federal and state regulation

What kind of regulatory structures and programs are in place in Illinois to safeguard public safety with respect to gas pipelines and related facilities? The ICC's Natural Gas Pipelines Safety division inspects natural gas pipeline facilities to ensure compliance with federal and state safety rules and regulations pertaining to the design, construction, operation and maintenance of those facilities. The Illinois Department of Natural Resources regulates the permitting and clean up of gas production wells along with flaring and venting. It also inspects storage fields in order to identify leaks that can contaminate water supplies including aquifers. The Illinois Environmental Protection Agency has regulatory oversight over the gas system's fugitive emissions and gas utilities must file annual reports detailing their estimates of their methane emissions. At the federal level, interstate pipelines are regulated by the Pipeline and Hazardous Material Safety Administration (PHMSA) of the U.S. Department of Transportation Division of Pipeline Safety. Natural gas storage sites are also regulated by PHMSA.

In terms of pipeline leaks, federal law 49 CFR 192.723 requires gas utilities to conduct periodic leakage surveys using "leak detector equipment" to identify leaks that could be hazardous to public safety or property. It also specifies the minimum frequency of these surveys. Hazardous leaks must be reported to PHMSA and promptly repaired, although specific timeframes are not required. PHMSA regulations leave the repair of non-hazardous leaks to the discretion of each gas utility. Most states have adopted more stringent safety regulations, often in response to gas incidents, public pressure, and changing public priorities, such as the need to reduce greenhouse gases. Illinois does not require more than the minimum federal standards for leak detection and repair related to its gas distribution networks.[89]

As directed by the federal bipartisan PIPES Act of 2020, PHMSA has proposed a new rule to significantly improve the detection and repair of leaks from gas pipelines, whether they are located in the distribution, transmission, or gathering systems, in natural gas storage facilities, or in liquefied natural gas facilities. For gas distribution systems, these new regulations, if adopted, are likely to require significant upgrades to utility leak detection and repair programs in Illinois, requiring more frequent leak surveys, expanded definitions of hazardous leaks, accelerated repair timetables, and enhanced leak monitoring.[90] More rigorous monitoring requirements for the upstream and midstream parts of the gas system will also be required. Also noteworthy for Illinois, in accordance with provisions in the federal Inflation Reduction Act of 2022, beginning in 2024, gas production, processing, transmission, and storage facilities and related pipelines will face charges for reported emissions surpassing thresholds that generally allow about 35 percent of emissions to occur "tax-free." The fees start at $900 per metric ton of methane emissions and increase to $1,500 after two years (these charges equate to $36 and $60 per metric ton of carbon dioxide equivalent).

In sum, the IRA's methane emission provisions along with proposed PHMSA reforms—if adopted—are likely to have a significant impact on leak detection and repair standards and protocols in Illinois. While these higher standards will benefit public safety and help lower emissions, they will result in higher operational and maintenance expenditures by gas utilities, which in turn will add to customer gas rates.

Leak reporting

To date, Illinois gas utilities have followed the minimum federal leak reporting standards. These require utilities to report certain broad types of leak information to PHMSA where they are publicly available in a 50-state gas distribution database. As part of its 2023 rate case orders, the ICC adopted recommendations by the Attorney General to strengthen utility leak reporting in order to provide

89 National Association of Pipeline Safety Representatives, "NAPSR Compendium 3rd Edition Final Revised" and "NAPSR State Survey Results, 3rd Edition" (2022), http://www.napsr.org/compendium.html.

90 For an overall analysis of PHMSA's proposed new regulations, see Dorie Seavey, *Leaked and Combusted: Strategies for reducing the hidden costs of methane emissions and transitioning off gas*, (March 2024, HEET), pp. 43-45, https://tinyurl.com/4dd9ru3d. For a presentation by the ICC Illinois Gas Pipeline Safety Program, see Matt Smith, "Leak Detection and Repair NPRM" (not dated), https://icc.illinois.gov/api/web-management/documents/downloads/public/Leak%20Detection%20and%20Repair%20NPRM%20Review.pdf.

greater transparency and to enable the Commission to assess the scope of system leaks and the effectiveness of utility efforts to identify, target, and remedy them. The ICC directed that, beginning July 1, 2024, each company is to report leaks by grade, cause, and facility type (i.e., material type and type of infrastructure) on an annual basis.[91]

Repair vs. replace

Little information is available about the extent to which Illinois gas utilities rely on repairing pipeline versus replacement.[92] Repairing pipeline is not a perfect substitute for replacing pipeline, and there are circumstances where replacing an at-risk section of pipe is required for public safety purposes and/or is the most cost effective option. But, when feasible, repairing a pipe with advanced leak repair technologies can be a far less expensive option than pipeline replacement, often extending the lifetime of the pipe by decades.[93]

Over the past decade in Illinois, the dominant emphasis on pipeline replacement has been encouraged by the Qualified Infrastructure Plant (QIP) program, the accelerated cost recovery program established by the General Assembly in 2014.[94] The program's purpose was to allow the gas utilities to prioritize and expedite several types of plant additions: pipe replacement (distribution and transmission), meter relocation, changing the pressure of pipe networks from low to medium, and replacing or installing transmission and distribution regulation stations, regulators, valves, and associated facilities to establish over-pressure protection. Over the same general time period, most states and the District of Columbia put in place rate mechanisms to encourage gas companies to replace leak-prone or older pipe in their gas distribution systems.[95] Under QIP, companies recouped their investment expenses outside of rates via a rider, subject to an annual reconciliation process. Capital spending under QIP was capped at an annual average of 4 percent of the gas utilities' base rate revenues or 5.5 percent in any given year. QIP sunsetted at the end of 2023, as provided for in the initial legislation.[96]

The Illinois QIP program was unique in allowing for spending on non-distribution infrastructure. One result has been that QIP was used heavily by Ameren and Nicor for Maximum Allowable Operating Pressure (MAOP) transmission pipeline reconfirmation projects. Transmission pipelines are subject to federal regulation under MAOP regulations (49 CFR § 192.619) which seek to increase the safety of gas transportation. Operators must take one of six actions to reconfirm the MAOP of previously untested gas transmission pipelines and pipelines lacking records. One of the methods is pipeline replacement; the others are pressure testing, pressure reduction, engineering critical assessment, pressure reduction for pipeline segments with small potential impact radius, and alternative technology.[97] These methods have widely varying costs, with replacement being the most expensive. Reconfirmations must occur for 50 percent of identified pipelines by 2028 and the remaining half by 2035. In general, Ameren and Nicor have used pipe replacement as the primary reconfirmation method.[98] In its 2023 Final Orders for both the Ameren and Nicor rate cases, the Commission declined to approve the company's

91 For an example of the ICC's order on leak reporting, see ICC, North Shore and Peoples Rate Case Order, Docket Nos. 23-00068 and 23-0069 (November 16, 2023), p. 65.

92 While Illinois gas utilities comply with minimum PHMSA leak reporting requirement which are reported in a federal database, with the exception of Peoples,the research team was unable to locate any regular reporting for gas distribution systems in which Illinois gas utilities provide information such as: leak repair costs per leak, total spending on leak repair, incidence of pipeline leaks by grade, incidence of pipeline repair, leak location mapping, and backlog of leaks present at year end. In its quarterly SMP reports, Peoples reports on the company's overall average leak rate and leak count, and also provides information on trends over time.

93 For example, National Grid reports average leak repair costs of $4,742 in its Boston, Massachusetts service territory. MA DPU, Docket No. 23-GSEP-03, Exhibit NG-GPP-9, Worksheet LPP Calc download.

94 IL Administrative Code, Title 83, Part 556.40. North Shore did not serve enough customers to charge a QIP fee.

95 NARUC, Natural Gas Distribution Infrastructure Replacement and Modernization: A Review of State Programs (January 2020), https://pubs.naruc.org/pub/45E90C1E-155D-0A36-31FE-A68E6BF430EE.

96 With their 2023 Rate Cases, each company transferred its qualifying infrastructure investment net of accumulated depreciation to its rate base. Thus, the investment included in Rider QIP as of December 31, 2023 was reset to zero as of that date. Even after QIP amounts are added to the rate base, they remain subject to reconciliation proceedings for each year. Peoples QIP investments for 2016 to 2023 have yet to be reconciled and approved as prudent by the ICC. Since customers are already paying these amounts through the rider, they will not see an incremental bill increase as a result of moving the investment into rate base.

97 The six actions are specified in 49 CFR § 192.624.

98 In Ameren's 2023 Rate Case proceeding, the Attorney General asserted that "there is substantial evidence in the record to show Ameren is unjustifiably front loading its MAOP work, without a plan, and well ahead of PHMSA's 2035 compliance period, while using replacement, the most expensive method, as the primary means to upgrade its infrastructure." ICC, 2023 Rate Case for Ameren, Docket 23-0067, Final Order (November 16, 2023), pp. 54-60, https://www.icc.illinois.gov/docket/P2023-0067/documents/344282/files/601209.pdf.

> **"The economic literature on leak repair vs. pipeline replacement makes clear that gas utilities have an incentive to over-invest in replacement because they are allowed to earn a rate of return on capital investments but not on leak detection and repair, which are treated as an operational expense."**

MAOP budgets as proposed, citing concerns about whether each company is "fairly considering its options when pursuing MAOP reconfirmation work." The Commission removed $47.5 million from Ameren's 2024 MAOP budget and $43.3 million from Nicor's budget and directed each company to submit a "comprehensive, cost-efficient Compliance Plan for satisfying the MAOP rule."[99]

This study was not able to locate data on leak repair costs for each utility and, with the exception of Peoples, we could not locate regular reporting on average costs for various kinds of pipeline replacement or installation. To roughly approximate the latter costs for Ameren and Nicor, we used information regarding expected costs and main feet or miles to be installed, as reported in each company's 2023 QIP Plan Update (North Shore was not eligible for the QIP surcharge; therefore, estimates were not possible for this company.) As shown in Table 3.1, in 2023, QIP-related spending per mile ranges from a low of $647,596 for Ameren to a high of $2.8 million for replacement projects that Peoples is undertaking related to "public and system improvements." Nicor's estimated spend per mile is $1.9 million. It should be noted that the Ameren figure appears low compared to known unit costs from around the country for installing or replacing distribution main.

Table 3.1: Spending to install a mile of distribution main by gas utility, 2023

	Spend per mile for main installed under QIP
Ameren	$647,596
Nicor	$1,885,687
North Shore	NA
Peoples	$1,200,000 - $2,800,000

Source: For Ameren and Nicor, calculations by GWD based on 2023 Annual QIP Plan Update (Docket Nos. P2014-0573 and P2014-0292, respectively). The QIP updates present expected year-end miles installed and total cost; it is unclear whether they include the cost of main retirement and whether they are fully loaded costs. For Peoples, see 2023 Q4 System Modernization Report. Note: the two values correspond to year-to-date costs of main install in two subprograms of the SMP (Neighborhood Program and the Public/System Improvement Program, respectively) and do not include the costs of main retirement.

The economic literature on leak repair vs. pipeline replacement makes clear that gas utilities have an incentive to over-invest in replacement because they are allowed to earn a rate of return on capital investments but not on leak detection and repair, which are treated as an operational expense.[100] In addition, gas companies lack the financial incentive to repair leaks in order to stop the waste of their primary product. They have regulatory approval to pass on the cost of the lost gas to their gas customers as a "normal" cost of doing business, and—at least for their distribution systems—they are not financially responsible for the climate and health costs caused by gas leaks.

99 ICC, 2023 Rate Case for Ameren, Docket 23-0067, Final Order (November 16, 2023), p. 91, https://www.icc.illinois.gov/docket/P2023-0067/documents/344282/files/601209.pdf and ICC, 2023 Rate Case for Nicor, Docket 23-0067, Final Order (November 16, 2023), pp. 38-39, https://www.icc.illinois.gov/docket/P2023-0066/documents/344366/files/601330.pdf.

100 See Dorie Seavey, *Leak and Combusted: Strategies for reducing the hidden costs of methane emissions and transitioning off gas* (March 2024, HEET), pp. 42-43, https://tinyurl.com/4dd9ru3d.

F. Regulating gas utility rates and revenue

Like most utilities in the United States, Illinois' investor-owned gas utilities operate as sanctioned monopolies, receiving regulatory protection and some guarantee of cost recovery for their gas system investments. In exchange for the privileges they enjoy as a monopoly—for example, market control and access to public property and rights of way—these utilities commit to extending and continuing service to any customer in their service territory.[101] The ICC strives to ensure that gas customers are provided with reliable, adequate, and efficient services at just and reasonable prices. It is responsible for regulating prices, resource planning and acquisition, reliability and service quality, and the safety of gas pipelines.

The ICC enforces the Illinois Administrative Code Title 83: Public Utilities and relevant provisions of the Public Utilities Act (220 ICLS 5). The Public Utilities Act (PUA) is an important vehicle for providing the ICC with the authority to direct and manage the gas transition, which includes discretion over rates and prudency of spending by gas utilities; coordination of long-term electric and gas system planning; and interpretation of statutes such as the obligation to serve. Currently, there are no gas service directives within the PUA that require the ICC to prioritize equity, affordability, and reductions in greenhouse gases to meet statewide greenhouse gas emissions limits.[102] However recent decisions by the ICC, such as the initiation of a "future of gas" proceeding, indicate that the ICC is working to prioritize these issues in the near-term, although further legislative action may be necessary to ensure that the Commission has sufficient regulatory authority and scope.

101 This commitment, referred to as the "obligation to serve" can be found in the Illinois Public Utilities Act: 220 ILL. COMP. STAT. 5/8-101, https://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=022000050K8-101. See BDC's recent report, *Decarbonizing the Obligation to Serve* for analysis on this statute across the U.S.: https://buildingdecarb.org/decarbnation-obligation-to-serve

102 Notably, the ICC does appear to have such directives with respect to electric services. See (220 ILCS 5/) Public Utilities, Article IV, https://www.ilga.gov/legislation/ilcs/ilcs3.asp?ActID=1277&ChapAct=220%26nbsp%3BILCS%26nbsp%3B5%2F&ChapterID=23&ChapterName=UTILITIES&ActName=Public+Utilities+Act%2E

Rate cases and rate setting

The primary tool of utility regulation is the rate case, a quasi-judicial administrative proceeding in which the regulatory commission determines allowed utility revenue ("revenue requirement"), customer prices (the "rates"), and the rate of return that utilities are permitted to earn on their capital spending. The Illinois PUA requires that all rates, charges, rules, and regulations made by a public utility be "just and reasonable" and that utility investments are "prudently incurred" and "used and useful."[103] During a typical rate case, then, utilities must justify their infrastructure investments and explain why they are necessary to meet customer needs. They must also provide information about what "prudent" and "reasonable" cost of service is and the rates that would allow the utility to fulfill its service obligations, recover its costs, and make a profit. The Office of the Attorney General represents and protects the interests of consumers and businesses while additional "intervenors" that represent the interests of environmental and consumer stakeholders, labor, business, etc. also participate. For example, the Illinois Citizens Utility Board, Environmental Law and Policy Center, and more recently, Illinois PIRG, engage in the Big Four's rate cases.

Rate cases determine three critical numbers for gas utilities that in turn shape whether customer rates will go up or down and by how much: the rate base, rate of return (or "cost of capital"), and revenue requirement. We review each of these important concepts in turn.

- **Rate base.** The rate base is the value of the utility's gas plant used to provide gas services that is approved by regulators as constituting the investment on which a fair rate of return is to be based. Gas plant (also referred to as "gas infrastructure") includes distribution mains, meters, and services; transmission mains; storage facilities; and other structures, property, and equipment. The rate base is calculated by adding up the original cost of the assets and adjusting for depreciation and other factors. The rate base grows when utilities invest above the rate of depreciation.

103 220 ILCS 5/9-101.

> **“Rate cases determine three critical numbers for gas utilities that in turn shape whether customer rates will go up or down and by how much: the rate base, rate of return, and revenue requirement.”**

- **Rate of return.** Investor-owned utilities engage in approved capital spending to maintain and upgrade their infrastructure, and they earn an authorized rate of return on their investments known as the “weighted average cost of capital.” That blended rate of return includes the profit rate that utilities are allowed to earn on their capital spending. This rate is then multiplied by the rate base to determine the amount of revenue needed to compensate utilities for the equity their shareholders invest, the cost of bond capital, whether it is short, medium, or long-term debt, and income taxes.
- **Revenue requirement.** The basis for setting a utility’s rates is known as the ”revenue requirement.” The revenue requirement refers to the total funds that an investor-owned utility needs to collect from its customers in order to pay for the gas system expenses it expects to incur in a given year. These expenses include the utility’s profit on its capital spending, operations and maintenance, depreciation, taxes, customer service, and administration. The revenue requirement also forms the basis of our modeling in this report, and is explained in more detail below.

Once the revenue requirement amount is established, then the rate case turns to “cost allocation,” or how this sum is to be spread across the various customer classes, the main ones being residential, industrial, and commercial. Rate design, which determines *how* these amounts will be collected from these classes (i.e., what portion is fixed or variable; any surcharges or related tariffs), also occurs at this step. The rates established by a rate case proceeding cover the cost of delivering gas to the customer’s gas meter, above and beyond the supply cost of gas itself.

G. How gas utility capital spending is recovered

Gas utilities in Illinois have been investing heavily in their gas systems over the past decade (see Section 3.I.4 below), thereby adding to their rate bases. These investments are the core of the gas utility business model because utilities earn a rate of return on them over the entire useful life of the assets, which in the case of gas pipeline extends roughly 40 to 70 years.

Consider an example: Assume a utility is retiring 5 miles of main and replacing it with 5 miles of new main at a cost of $2 million per mile. Assume further that mains have an expected life of 60 years. To make this investment, the utility will need to raise money from its investors and the bond market. Each year for 60 years, the utility will seek to recover two principal costs from customers through the company’s revenue requirement: a depreciation expense equal to 1/60th of the capital spending and a rate of return on the undepreciated balance of the investment. The rate of return is set by the regulator at the time of the utility’s rate case and is increased or “grossed up” to cover the net federal plus state tax rate. In Illinois, it is also grossed up to include the “uncollectibles rate,” that is, expenses the utility incurs due to uncollectible gas bills (“bad debt”). Assuming a 9 percent annual rate of return and a 2 percent escalation rate for prices, the $10 million investment today for 5 miles of new main results in $37.45 million of costs to be recovered from customers over the next six decades. In other words, the fully loaded cost that ratepayers will pay for these 5 miles of infrastructure is nearly four times the initial investment in the year that the retirement/replacement work occurred—and that cost is locked in for many decades to come.

> **“Even if the utility stops investing in gas system assets today, customers continue paying for prior investments well into the future.”**

This example shows a critical dynamic in gas utility cost recovery for investor-owned utilities: even if the utility stops investing in gas system assets today, customers continue paying for prior investments well into the future. We call this multiplying cost phenomenon the “undertow effect,” as it demonstrates how previous capital spending is baked into the rate bases of each utility. In other words, capital spending that occurred in the past continues to play a significant role in today’s revenue requirement and therefore the rates that are charged to gas customers. As we show later in this report, in Illinois, even assuming a best-case scenario of flat capital spending for each of the four gas utilities accompanied by moderate customer departure, by the mid- to late-2030s average delivery costs per customer still double for each gas utility.

Going forward, evaluating the prudency of gas system investments is critical given the significant consequences for customer rates of lengthy depreciation timelines for the major gas system assets and their high cost of replacement. Gas utilities in Illinois continue to replace and sometimes expand their gas infrastructure in line with the expectation that gas consumption will continue for decades to come. But this expectation conflicts with the state’s decarbonization goals. A new gas main installed today on a city street (with its accompanying service lines and meters) is likely to become unused or underutilized during its design lifetime as the economy switches to clean, renewable energy sources. In other words, the physical capital will be stranded and some portion of the value of the asset will be stranded too, since the cost of the new main, services and meters will not have been fully recovered by the time the asset is abandoned. As detailed in Section 5, over $13 billion of investments already made by the four largest gas utilities remain to be recovered through future customer rate payments.

H. How gas customers pay for gas

Utility bills in general are known for being difficult to decipher, in part because of the multiplicity of charges and in part because many of the charges themselves are the result of complex calculations. Here we draw the direct line between utility spending and utility bills in order to demonstrate how the increasing costs of the gas system affect everyday Illinois utility customers. We also explain how customers are charged for the cost of the gas itself.

Delivery charge

For gas utility customers, the end result of a rate case is a revised set of “delivery charges” on their monthly bills. Delivery charges tie directly to the revenue requirement described above. The higher the revenue requirement, the higher the delivery charges that customers see on their bills.

The delivery charge has a fixed and variable component. Fixed customer charges do not vary with usage whereas variable charges depend on the amount of gas used by a customer (a volumetric per-therm rate). Regulators set the proportion of base revenue that can be recovered via fixed vs. variable delivery charges. The fixed customer charge creates revenue stability for gas utilities, protecting them from the risk of declining throughput. Currently, North Shore, Peoples Gas, and Nicor collect most of their residential revenues through fixed charges while Ameren collects a greater percentage of residential revenues through a volumetric charge.

Fixed charges were a controversial part of the recent 2023 Big Four rate cases. In its final orders for each company, the ICC declined to meet the gas utilities' requests for higher fixed charges.[104] The new fixed charges for heating customers set by the ICC, inclusive of smaller tariff fees, are: Ameren at $20.89, Nicor at $18.88, North Shore at nearly $24, and Peoples at $27.32.[105]

> **"Fixed charges were a controversial part of the recent 2023 Big Four rate cases. In its final orders for each company, the ICC declined to meet the gas utilities' requests for higher fixed charges."**

Riders and surcharges

In addition to fixed and variable delivery charges, riders and surcharges have played an important role in the revenue collected from Illinois gas customers. These charges take place outside of the rate structure and have been tied to infrastructure replacement, energy efficiency, environmental clean-up programs, and bad debts. In recent years, the biggest rider has been for the Qualifying Infrastructure Plant (QIP) program. On the occasion of the next rate case, QIP assets created since the last rate base would then be eligible for inclusion in the new rate base.

The next largest rider for most companies is the uncollectibles expense adjustment rider. Uncollectibles refer to amounts billed to customers that remain unpaid and are eventually deemed uncollectible. Utilities recover an annual average amount for uncollectibles in their base rates (as approved by the ICC) but in addition they are permitted to recover through a tariff the incremental difference between actual uncollectible amount and the uncollectible amount included in the utility's rates. As delivery charges increase, or in times of gas price volatility, the rider, together with base rate recovery for bad debt, substantially mitigate credit risk for utilities.

Supply charge

Gas companies purchase methane gas on behalf of their customers and these purchased gas costs are passed through to customers on a dollar-for-dollar basis as "supply charges" without markup. These charges appear on monthly customer bills along with the delivery charges explained above.

Supply charges vary monthly and are set by the market. They can show considerable volatility to weather and, more recently, to international supply and demand pressures. This volatility can directly affect bill affordability. During Winter 2021-2022, for example, gas bills in Illinois increased by 41 to 206 percent, depending on the utility, due to "a surge in demand that accompanied the pandemic recovery, the impact of Hurricane Ida on gas production in the Gulf Coast, and severe storms…that froze natural gas pipelines in Texas, thereby reducing the supply."[106] At the time, the Citizens Utility Board commented: "[previously] it was easier for companies to increase delivery rates without customers taking as much notice because the price of gas was low…Now that the price of gas is going through the roof, (customers) are noticing the increase in bills."[107] On the other hand, when gas commodity prices are on a downward trend—as they were from 2014 to 2020—they can mask the fact that delivery charges are increasing due to increased capital spending on gas infrastructure and rising operations and maintenance expenses.[108]

104 The Attorney General and various environmental and consumer stakeholder intervenors argued that higher fixed charges for gas have the perverse effect of decreasing the economic attractiveness of electrification for ratepayers and result in unaffordable fees that customers must pay before they use a single therm of gas.

105 See Citizens Utility Board, "The Customer Charge and Distribution Charge," https://www.citizensutilityboard.org/gas_makingsense/.

106 Barbara Vitello, "Check Your Natural Gas Bill Lately? Why They're Soaring This Winter." *Shaw Local News Network*, January 8, 2022. https://www.shawlocal.com/news/2022/01/09/check-your-natural-gas-bill-lately-why-theyre-soaring-this-winter/.

107 Ibid.

108 Citizens Utility Board, "Average Yearly Gas Supply Charges, Major Illinois Utilities," https://www.citizensutilityboard.org/gassupplycharges/.

Discounted rates for low-income gas customers

Many gas customers struggle to pay their bills. During 2023, Peoples and Nicor assessed late fees each month for an average 28 percent and 20 percent of their residential customers, respectively.[109] As of the end of January 2024, residential arrearages totaled $83.7 million for Peoples, $64.6 million for Nicor, and $23.2 million for Ameren.[110] In an effort to aid low-income customers with their utility bills, the ICC recently ordered Peoples, Nicor, and North Shore to implement a tiered discount rate system by October 2024 (the Low Income Discount Adjustment or, LIDA). The rulings establish a five-tiered, income-based discount tied to federal poverty guidelines and applied to the whole bill. The tiers range from a 5 percent discount for customers with a household income up to 300 percent of the federal poverty level up to 75 to 83 percent discount for customers with income below half the poverty level.[111] The discounts are to be subsidized by other ratepayers who will no longer be charged an Uncollectibles Expense Rider that reimburses the utility for bad debt (i.e., amounts billed to customers that are deemed uncollectible). The discount rates were set with the goal of ensuring that customers pay no more than 3 percent of their monthly income toward heating bills. A similar five-tiered discount rate was also approved for Ameren. Washington is the only other state that has mandated a similar discounted system.

Another source of bill pay assistance is the federal/state LIHEAP (Low Income Home Energy Assistance Program) which is available to households at or below 200 percent of the federal poverty level.[112] Applicants can apply for a direct vendor payment (payable directly to the utility) determined by income, household size, fuel type, and location, or they can apply for the Percentage of Income Payment Plan (PIPP) under which they pay a percentage of their income and receive a monthly benefit toward their utility bill based on their income level. PIPP also provides for a reduction in overdue payments for on-time payments. During the Covid pandemic, Congress authorized temporary funds for LIHEAP which significantly increased the available resources. Starting with the 2023/2024 winter season, funding levels for Illinois fell to $280 million, down from $406 million in 2022. Illinois supplements these appropriations through a surcharge that is built into utility rates on customer bills (this charge has remained unchanged since 1999).

109 ICC, 2024 Monthly Filings for each utility at ICC's website for Credit, Collections, and Arrearages Reports, https://www.icc.illinois.gov/chief-clerk-office/filings/list?sd=638081280000000000&dts=365&ft=2&dt=240&ddt=10128.

110 ICC, 2024 Monthly Filings for each utility at ICC's website for Credit, Collections, and Arrearages Reports, https://www.icc.illinois.gov/chief-clerk-office/filings/list?sd=638409600000000000&dts=365&ft=2&dt=240&ddt=10128.

111 The 83% discount is for Peoples and the 75% discount for the other three companies.

112 LIHEAP provides one-time payments directly to utility providers on behalf of low-income households at or below 200% of the federal poverty level, or $60,000 for a family of four. Funds are also provided for home weatherization, crisis assistance such as for a broken furnace, and reconnection assistance. In Illinois, the program is administered by the IL Department of Commerce and Economic Opportunity.

I. The “Big Four”: Infrastructure, customers, and throughput

If gas companies could pick up their infrastructure and redeploy it elsewhere, the transition options would be very different. But gas assets are very costly to install, and once installed they are essentially not redeployable—they are literally sunk in the ground—with no secondary markets. This has been true since the very beginnings of the industry and is why analysts refer to new capital spending on gas assets as “locked in.”

This section provides an overview of the gas infrastructure and customer base of the Big Four gas utilities. (Detailed profiles of the gas assets of each company are provided on page 30)

1. Types and amounts of gas system assets

The gas systems of Illinois’ Big Four consist of three main types of infrastructure assets: distribution, transmission, underground storage. In addition, two of the utilities—North Shore and Peoples—own peaker plants (an LNG plant for Peoples and a propane-air facility for North Shore).[113] Table 3.2 compares gas system assets or “gas plant” across the four companies. Nicor is the largest of the four companies in terms of distribution mains and services. Ameren is the next largest with about half as many distribution mains but more transmission pipelines. Ameren also has more underground storage fields than any other company. North Shore and Peoples have the smallest systems but they serve many more customers per service line or main.

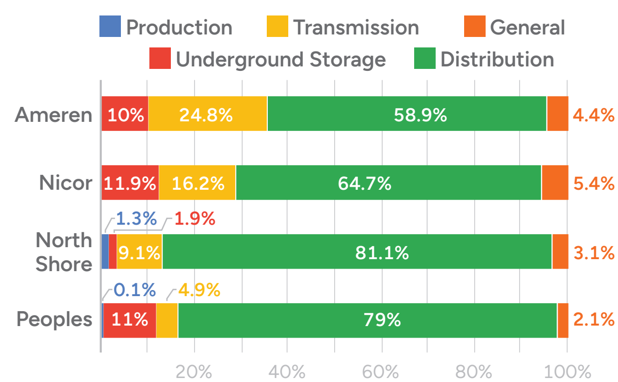
Table 3.2: Gas system infrastructure, 2022

	Ameren	Nicor	North Shore	Peoples
Distribution mains (miles)	17,456	33,616	2,360	4,678
Distribution services (count)	813,274	2,054,463	143,473	499,354
Transmission mains (miles)	1,224	1,164	68	346
Underground storage facil-ities	12	8	0	1
LNG or propane-air plant	0	0	1	1

Source: GWD analysis of PHMSA Form 7100.1 for distribution mains and services, and of ICC Annual Report 2022 to ICC, Form 21 ILCC for transmission mains.

While distribution assets make up the majority of each gas system, this share varies from 59 percent for Ameren up to 81 percent for North Shore (see Figure 3.5). A quarter of Ameren’s system is invested in transmission assets compared to just 5 percent of the Peoples. Storage assets make up 10-12 percent of the Ameren, Nicor, and Peoples systems. North Shore rents storage capacity from Peoples.

Figure 3.5: Composition of gas plant assets by company, 2022



Source: GWD analysis of Annual Reports for 2022 filed with the ICC (Form 21 ILCC), “Gas Plant in Service.”

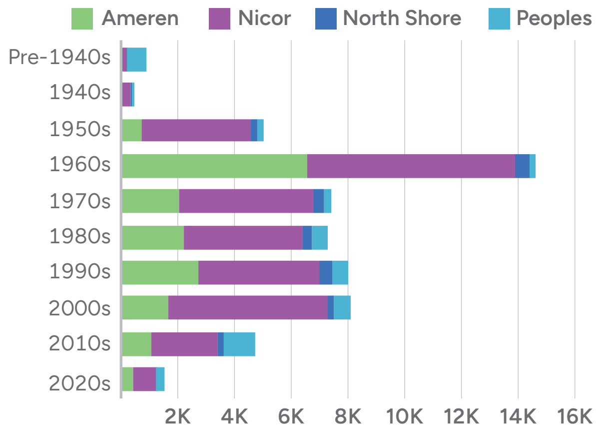
2. Pipeline age

Over time, pipeline integrity has benefitted from improvements in pipe manufacturing, pipe materials, construction methods, and maintenance practices. But as pipelines age, their risk profile

113 For the LNG plant, the LNG is stored in large, insulated above-ground tanks. The plant also consists of a liquefaction system, a vaporization system, LNG pumps, and other associated equipment. The plant is designed to liquefy gas received from pipelines, store it in the tanks as LNG, and then vaporize it back into the gas when required and then injected into the transmission system. The propane-air facility also requires a vaporizer and can inject a propane-air mixture into pipes.

increases nonetheless because the pipes become more likely to corrode, splinter and/or leak, other things equal. As shown in Figure 3.6, a substantial amount of Illinois' existing distribution system (36 percent) was installed prior to 1970 and is now more than 50 years old.

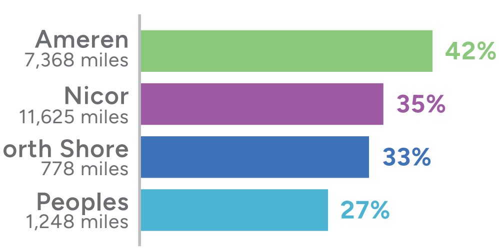
Figure 3.6: Distribution mains by decade installed (in miles)



Source: PHMSA Form 7100.1

While the Peoples gas system receives attention for its aging, leak-prone distribution system, it is actually Ameren and Nicor that have the oldest gas systems in the state, with 42 percent and 35 percent of their distribution mains installed prior to 1970, respectively (see Figure 3.7).

Figure 3.7: Proportion of existing distribution mains installed pre-1970 by company



Source: PHMSA Form 7100.1

If Illinois' gas system is to be maintained, the advancing age distribution of the distribution system has important implications for the future capital expenditures likely required to replace successive cohorts of aging pipeline. As shown in Figure 3.7, there are over 21,000 miles of distribution mains in the Illinois gas distribution system that have reached 50 years or more of age. The vast majority

> **"There are over 21,000 miles of distribution mains in the Illinois gas distribution system that have reached 50 years or more of age."**

of this pipeline (90 percent) is located in the Ameren and Nicor gas distribution territories. During its 2023 rate case, Nicor makes clear that it has transitioned its focus from replacing bare steel and vintage plastic to replacing vintage steel,[114] a material not necessarily categorized as "leak prone" by PHMSA. Nicor underscored that "the longer an asset remains in service, the higher the probability of a significant distribution incident,"[115] disagreeing with an expert who described the Nicor system as consisting mostly of "modern materials" with relatively lower level of risk. Instead, Nicor argued, the company's system still has over 4,300 miles of pre-1960 main that now present a known risk.[116] Nicor offered that, "assuming 100 miles of pre-1960 steel mains are replaced every year after 2022, the company would not eliminate this known risk from its system…until 2066, at which point the last remaining pre-1960 main would be at least 107 years of age."[117]

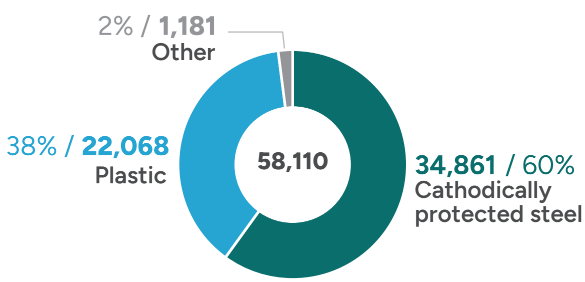
Neither Nicor or Ameren provide a particular pace for replacing vintage steel distribution mains, but it appears that planning for this replacement is ongoing. We take the likely implications of this main replacement planning into account in our scenario modeling presented in Section 5.

114 Illinois Commerce Commission, 2023 Rate Case of Nicor, Docket 23-0066, Nicor Gas Exhibit 36.0 (July 12, 2023), p. 10.
115 Illinois Commerce Commission, 2023 Rate Case of Nicor, Docket 23-0066, Nicor Gas Exhibit 36.0 (July 12, 2023), p. 13.
116 Illinois Commerce Commission, 2023 Rate Case of Nicor, Docket 23-0066, Nicor Gas Exhibit 36.0 (July 12, 2023), p. 45.
117 Illinois Commerce Commission, 2023 Rate Case of Nicor, Docket 23-0066, Nicor Gas Exhibit 36.0 (July 12, 2023), p. 13.

3. Pipeline material

The age of pipeline material is important and so is the material it is made of. The U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) provides broad guidelines on the categorization of distribution pipeline material. Using PHMSA reporting categories, only 2 percent of the distribution pipeline of the Big Four is identified as strictly leak prone, consisting of cast iron, wrought / corrugated / ductile / reconditioned iron, or unprotected steel.[118] Of the remainder, 60 percent consists of cathodically protected steel and 38 percent is made of plastic (see Figure 3.8).

Figure 3.8: Distribution mains by material, 2022



Source: PHMSA Form 7100.1

The question of leak-prone material becomes more complex when vintage plastic and mechanically coupled steel (which for PHMSA reporting purposes may be included in "cathodically protected steel" category) are considered. While PHMSA does not require gas utilities to break out their plastic pipes by type of plastic or to report their mechanically coupled steel, PHMSA does recognize the potential for mechanical couplings to fail and the gas industry considers certain types of vintage plastic to be leak prone (for example, DuPont Aldyl "A" and CAB plastic).[119] Investor-owned gas utilities in Illinois file an Annual Gas Performance Report which reports more granular information on the materials of pipeline *replaced* compared to the PHMSA reporting. Specifically, gas utilities must account for: "the miles of main and number of services replaced that were constructed of cast iron, wrought iron, ductile iron, unprotected coated steel, unprotect bare steel, mechanically coupled steel, copper, cellulose acetate butyrate (CAB) plastic, pre-1973 DuPont Aldyl "A" polyethylene, PVC or other types of materials identified by a state or federal agency as being prone to leakage."[120]

These reports unfortunately do not provide an inventory of the total amounts of mains containing these materials. However, it is clear that both the Ameren and Nicor systems have some amount of DuPont Aldyl A plastic and mechanically coupled steel. In addition, the Peoples system contains services made of CAB plastic.

Leaving Peoples aside, the amount of pipeline material traditionally considered leak prone in Illinois is very modest, even allowing for the leak-prone pipe present in the Ameren and Nicor systems and not accounted for in PHMSA accounting. In contrast, there are distribution systems in the United States where the presence of leak-prone materials is much greater (e.g., Massachusetts, Philadelphia, and Maryland). An important take-away for Illinois is that the overall age of the pipeline will drive the need for pipeline replacement more than its material. This means that continuing gas as a fuel source for buildings and commercial/ industrial concerns means preparing for waves of significant capital spending to replace each aging cohort of gas mains and services.

4. Trends in capital spending on gas plant

From 2014 to 2022, each of the Big Four utilities accelerated their capital spending on distribution, transmission, and storage plant and together invested just over $9 billion in their gas systems. These costs are expected to be recovered with a rate of return over a period of 40 to 70 years, depending on the type of asset.[121] Because of this

118 Nicor has 23 miles of unprotected steel left and Peoples has just over a 1,000 miles remaining of various kinds of iron pipe that are considered leak prone.

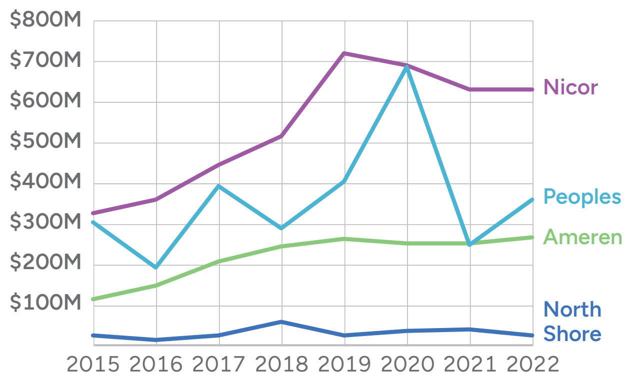
119 See https://icc.illinois.gov/downloads/public/edocket/592783.PDF and https://www.aga.org/wp-content/uploads/2022/12/plastic-pipe-timeline-06282022.pdf.

120 220 ILCS 5/5-111, https://www.ilga.gov/legislation/ilcs/documents/022000050K5-111.htm.

121 Each company filed a Depreciation Report as part of its 2023 Rate Case. Those reports provide Survivor Curve values that can be used to estimate the average service life (ASL) of different categories of assets. Using this method, we can say that Ameren, Nicor, North Shore, and Peoples use an ASL of 68, 72, 63, and 67 for new distribution mains.

spending, total gas plant increased by 84 percent, from $11 billion in 2014 to $20.2 billion in 2022.

Figure 3.9: Total capital spending by gas utilities on distribution, transmission, and storage, 2014-2022

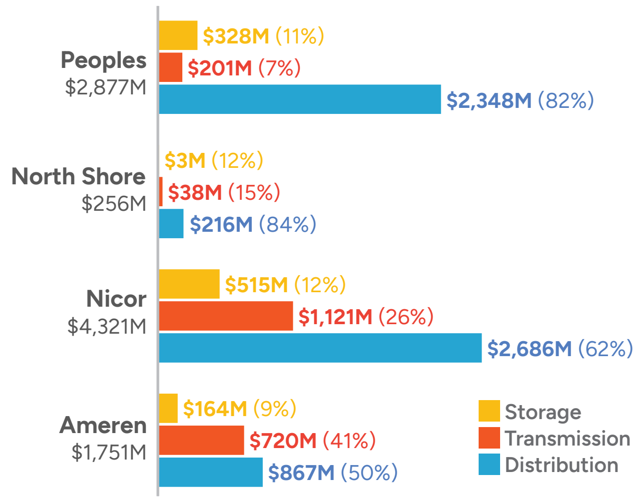


Source: Calculations by GWD from LDC Annual Reports filed with the ICC (Form 21 ILCC), 2015-2022, "Gas Plant in Service."

For the same period, Figure 3.10 shows the composition of gas utility spending by major gas plant category:

- **Distribution** infrastructure received the bulk of the investment, ranging from 50 percent by Ameren up to 84 percent by North Shore.
- **Transmission** investments have been an important focus for Ameren at 41 percent and Nicor at 26 percent. Spending on transmission is tied to compliance requirements associated with PHMSA regulations, particularly those addressing MAOP reconfirmation (see Section 3.E) and/or pipelines with a higher risk of failure such as exposed mains.
- **Underground storage** capital spending ranged from 9 percent to 12 percent across the four utilities. These facilities require equipment for injecting, withdrawing, and sometimes compressing and dehydrating the gas.

Figure 3.10: Composition of total gas plant capital spending by utility, 2015-2022



Source: GWD analysis of Annual Reports filed with the ICC (Form 21 ILCC), 2015-2022, "Gas Plant in Service."

For the three largest utilities, a significant proportion of these investments occurred under the QIP program (see Section 3.E).

In addition to capital spending on replacing extant infrastructure, gas companies in Illinois have also to a lesser extent invested in new growth; that is, they have continued to build out and extend their networks. This is accomplished by offering ICC-approved line extension allowances (LEAs) to attract new customers, subsidies that are paid for by an increase in gas rates. These allowances cover some or all of the costs for the new connection as well as encourage the purchase of gas equipment and appliances. For example, free of charge to the new customer:

- Nicor will extend 100 feet of low pressure main or 200 feet of high pressure main as well as 60 feet of service for a new customer free of charge. [122]
- Ameren will extend 400 feet of main line and 60 feet of service line.

The research team for this study was unable to locate a comprehensive accounting of the cost of LEAs in Illinois and quantities of miles and services installed. However, Ameren's testimony in its 2023 rate case establishes that its recent annual spending rate for line extensions is $22 to $24 million, and Nicor indicated that its allowances for mains ranged

122 Nicor Gas. "Offers and Incentives." https://www.nicorgas.com/business/build-with-natural-gas/offers-and-incentives.html.

up to $15,202 per customer in 2023.[123] In some states, the cost of LEAs to ratepayers have been found to be substantial. California gas customers have been paying an estimated $164 million annually for these extensions while ratepayers in Oregon, Washington, and Colorado have likely paid more than $100 million per year.[124] Some states are taking steps to dismantle these subsidies.

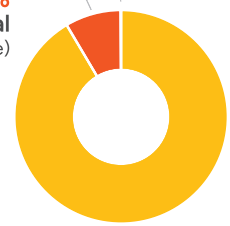
We now turn to an in-depth overview of gas plant capital spending by each of the Big Four.

5. Trends in customers and throughput

Customer composition

Illinois' Big Four gas utilities serve over 4 million gas customers.[125] Residential customers (heating and non-heating) make up over 90 percent of these customers (see Figure 3.11). Commercial customers ("small and intermediate") make up another 9 percent and industrial/other customers comprise the balance.[126]

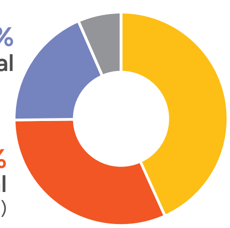
Figure 3.11: Statewide gas customer composition, 2024 test year



Source: GWD analysis of "Jurisdictional Operating Revenue" (present revenue by delivery service classification for future test year 2024), Schedule E-5 from 2023 Rate Case dockets for Ameren, Nicor, North Shore, and Peoples.

The composition of total gas throughput by customer looks very different from the customer composition. As shown in Figure 3.12, residential customers account for 43 percent of throughput, commercial customers for 32 percent, and industrial for 19 percent (including large general, large volume and other industrial). In addition, about a dozen very large contract customers (some involving electrical generation) are captured in the "Other" category at 7 percent.[127]

Figure 3.12: Statewide gas throughput consumption by customer type, 2024 test year



Source: GWD analysis of "Jurisdictional Operating Revenue" (present revenue by delivery service classification for future test year 2024), Schedule E-5 from 2023 Rate Case dockets for Ameren, Nicor, North Shore, and Peoples.

On a per therm basis, industrial customers are of course the largest consumers. For residential customers, annualized therm consumption ranges from about 700 therms in the Ameren territory to 1,400 in North Shore (see Table 3.3).

123 ICC, Ameren 2023 Rate Case, Docket 23-0067, PIO Ex 1.0, p.40 and ICC, Nicor 2023 Rate Case, PIO Exhibit 1.2, Docket 23-0066, Nicor Response to PIO 3.08.

124 Dorie Seavey, *Leaked and Combusted: Strategies for reducing the hidden costs of methane emissions and transitioning off gas* (March 2024, HEET), pp. 62-63, https://tinyurl.com/4dd9ru3d.

125 This analysis of customers and throughput excludes public authorities. This customer category is relevant only to Ameren which, in 2022, had 1,122 customers that were public authorities. Their therm usage was 2.7 million. In addition, the ICC's accounting excludes the activity of municipally- and cooperatively-owned gas utilities. See: https://www.icc.illinois.gov/downloads/public/ng/22-21Comparison%20of%20Gas%20Sales%20Statistics.pdf.

126 This account allocates "transportation" customers to the appropriate functional categories. These customers make up about 7% of total customers and consist of residential, commercial, and industrial customers; they purchase their gas from another entity but have it delivered by the gas utility. The data source employed is Schedule E-5 from the 2023 rate case dockets of gas utilities. For an example of a gas utility customer choice program in Illinois, see Ameren's "Natural Gas Choice" program, https://www.ameren.com/illinois/residential/supply-choice/gas-choice.

127 "Other" also includes non-residential customers that are either seasonal, use compressed gas for vehicles, or are covered under "inadequate capacity" special arrangements.

Table 3.3: Therms sold per customer type by gas utility, 2024 test year

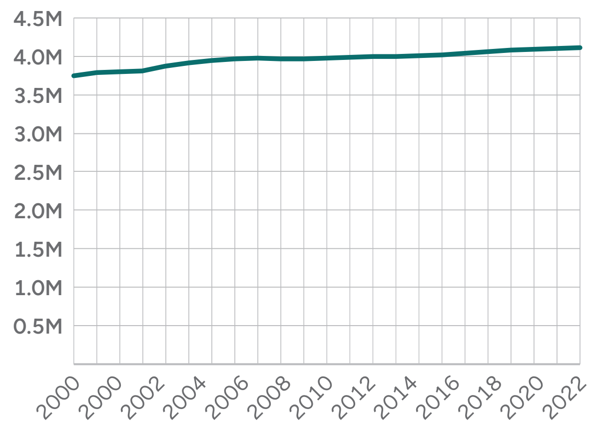
Therms Per Customer	Ameren	Nicor	North Shore	Peoples
Residential	702	1,084	1,358	921
Commercial	3,968	8,514	8,476	9,106
Large general	2,342,707	2,590,179		
Large volume		28,723,167	2,313,000	1,544,986
Contract service	91,990,527	34,015,000		14,176,500
Seasonal	79,093	161,078		
Compressed vehicle gas				117,600
Inadequate capacity	58,061			

Source: GWD analysis of "Jurisdictional Operating Revenue" (present revenue by delivery service classification for future test year 2024), Schedule E-5 from 2023 Rate Case dockets for Ameren, Nicor, North Shore, and Peoples.

Trends in customers and gas throughput

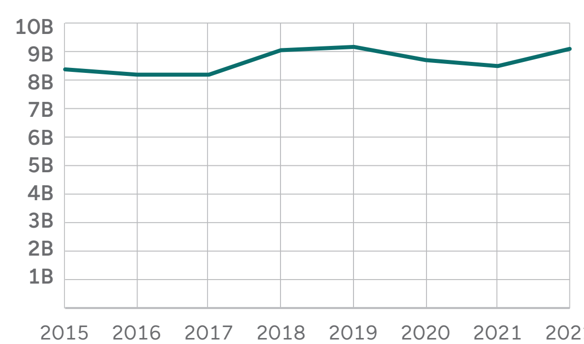
Trends in customers and throughput are key to determining the future affordability of Illinois' gas system. As building efficiency measures, average temperatures, and electrification all increase, infrastructure costs will be spread over fewer numbers of customers consuming a shrinking gas volume. Section 2 of this report describes the dramatic post-World War II growth in Illinois' gas system, which continued through the 1960s. In sharp contrast, over the past 22 years (2000 to 2022), the number of total gas customers served by the Big Four shows a flat trend line (0.5 percent year-over-year increase as shown in Figure 3.13). Since 2015, therms have shown a slight upward trend of 1.2 percent year-over-year (although therms sold in 2022 were still below their 2019 level).[128] This pattern of very slow to no growth is consistent with the market saturation concept described in Section 2—namely, that the Illinois' gas industry has largely saturated its potential markets and has entered a "post-expansion" era. On top of this, the new energy transition makes it extremely likely that the trends described here will turn down and become irreversibly negative.

Figure 3.13: Big Four total customer count, 2000- 2022



Source: GWD analysis of ICC Comparison of Gas Sales Statistics, various years.

Figure 3.14: Big Four total therms sold, 2015-2022



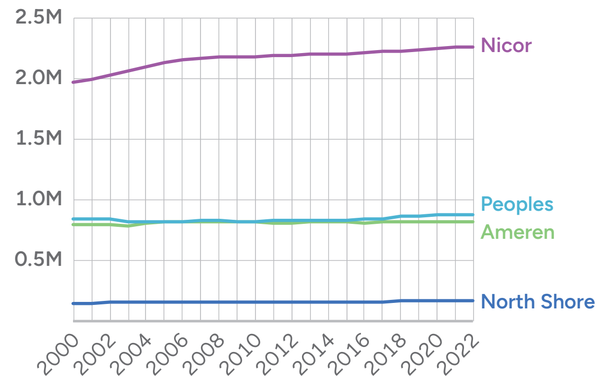
Source: GWD analysis of ICC Comparison of Gas Sales Statistics, various years.

128 GWD analysis of ICC Comparison of Gas Sales Statistics, various years, https://www.icc.illinois.gov/icc-reports/report/comparison-of-gas-sales-statistics.

Figures 3.15 and 3.16 break out these customer and therm trends for each of the four gas utilities. Here are standout points for each company:

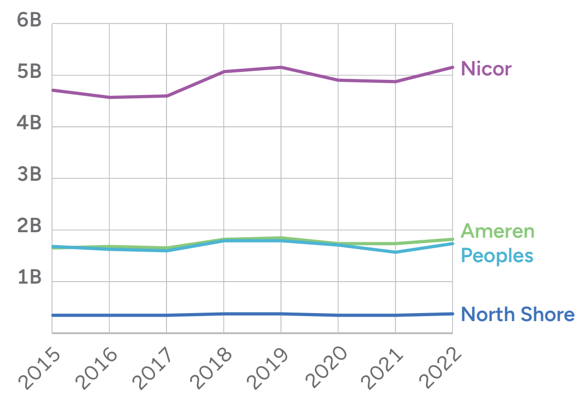
- **Ameren.** After accounting for Ameren's three-company acquisition and mergers in the early 2000s, customer base growth for the Ameren territory was only 3 percent from 2000 to 2022.[129] From 2015 to 2022, therms sold increased by 10.3 percent (1.5 percent year-over-year).
- **Nicor.** Nicor's customer base has grown the most of any gas utility; Nicor had 15 percent more customers in 2022 than in 2000. From 2015 to 2022, therms sold increased by 9.6 percent (1.4 percent year-over-year).
- **Peoples and North Shore.** Both Peoples and North Shore lost customers between 2000 and 2015, but their customer counts in 2022 were near or above their 2015 levels. From 2015 to 2022, therms sold increased by 8.6 and 3.9 percent for Peoples and North Shore, respectively (1.2 and 0.6 percent year-over-year, respectively).

Figure 3.15: Trends in total customer counts by gas utility, 2000-2022



Source: GWD analysis of ICC Comparison of Gas Sales Statistics, various years.

Figure 3.16: Trends in total therms sold by gas utility, 2015 to 2022



Source: GWD analysis of ICC Comparison of Gas Sales Statistics, various years.

129 For the analysis presented in this section, the project team treats Central Illinois Light and Illinois Power Company essentially as part of Ameren between 2000 and 2004 since CIL and IPC were subsequently acquired by Ameren.

Section 4

RNG Won't Fix the Future of Gas in Illinois

A. Key takeaways

- The gas industry in Illinois proposes to use renewable natural gas (RNG) as an avenue to achieve emissions reduction targets without downsizing the gas pipeline network. RNG can be produced from various biomass feedstocks through different pathways.
- The carbon footprint of RNG varies considerably according to, among other things, its feedstock, transportation, and the accounting framework used to measure emissions reductions.
- The bioenergy resources that can be used to produce RNG are limited and face competition from higher-value uses such as areas where electrification is more challenging, including sustainable aviation fuel or carbon dioxide removal. Allocating limited bioenergy resources to RNG for building heating rather than to harder-to-electrify sectors will make it more difficult for those sectors to decarbonize. Renewable fuel strategies should thus take an economy-wide approach.
- RNG is an exceptionally expensive decarbonization pathway that does not create any new value for gas customers. Current city-gate costs for methane gas hover around $0.50 per therm; a pilot RNG tariff from NICOR implies $2 per therm for RNG; demand at larger scales will likely result in costs of over $3 per therm due to the need to procure higher cost feedstocks for RNG. At scale, energy customers would incur burdensome costs. Additionally, scaling RNG for heat will likely be constrained by new federal incentives for transportation biofuels and carbon sequestration. Hydrogen faces similar challenges and has limited ability to substitute for fossil gas in existing pipelines.
- Illinois is potentially one of the most "bioenergy rich" states in the U.S. because of its significant cropland resources that can be used to grow energy crops. The highest and best use of Illinois' potential bioenergy capacity requires broad sectoral planning beyond the ICC's regulatory purview.

B. Introduction

The gas industry has identified renewable natural gas (RNG) as a potential pathway to align its operations with climate objectives by substituting RNG for fossil gas.[130] This section examines how RNG is produced and its emissions implications in the broader context of Illinois' bioenergy resources.

130 For an example of an Illinois gas utility, see: Nicor Gas, "Renewable Gas," https://www.nicorgas.com/sustainability/renewable-gas.html and WEC Energy Group, *Pathway to a Cleaner Energy Future: 2021 Climate Report* (2021), https://www.wecenergygroup.com/csr/climate-report2021.pdf. For the gas industry, see: American Gas Association. *Net-Zero Emissions Opportunities for Gas Utilities* (2021), aga.org/globalassets/research--insights/reports/aga-net-zero-emissions-opportunities-for-gas-utilities.pdf.

We explore why RNG is a prohibitively expensive decarbonization strategy for Illinois' building decarbonization efforts and consider the need to examine its broader ramifications outside the regulation of the gas system. Ultimately, this section concludes that there are higher-value uses for the resources that could otherwise be used to make RNG in Illinois.

C. How RNG and bioenergy is made

Bioenergy refers to energy that is derived from recently living organic materials ("biomass") and that can be used to produce transportation fuels, heat, and electricity. RNG is one of several types of bioenergy. Figure 4.1 highlights the numerous pathways for transforming different kinds of biomass ("feedstocks") into usable bioenergy. The details of these pathways are beyond the scope of this report, but the reader should understand that:

- Almost any biomass feedstock can be turned into any fuel via several processing steps. RNG is not the only pathway available.
- Different pathways result in distinct energy, cost, emissions, environmental, and social tradeoffs that vary depending on the feedstock, the scale of use of the feedstock, the type of processing, and the end product.
- RNG is pipeline quality methane. It is practically indistinguishable from fossil methane and can have the same climate impact when it leaks.

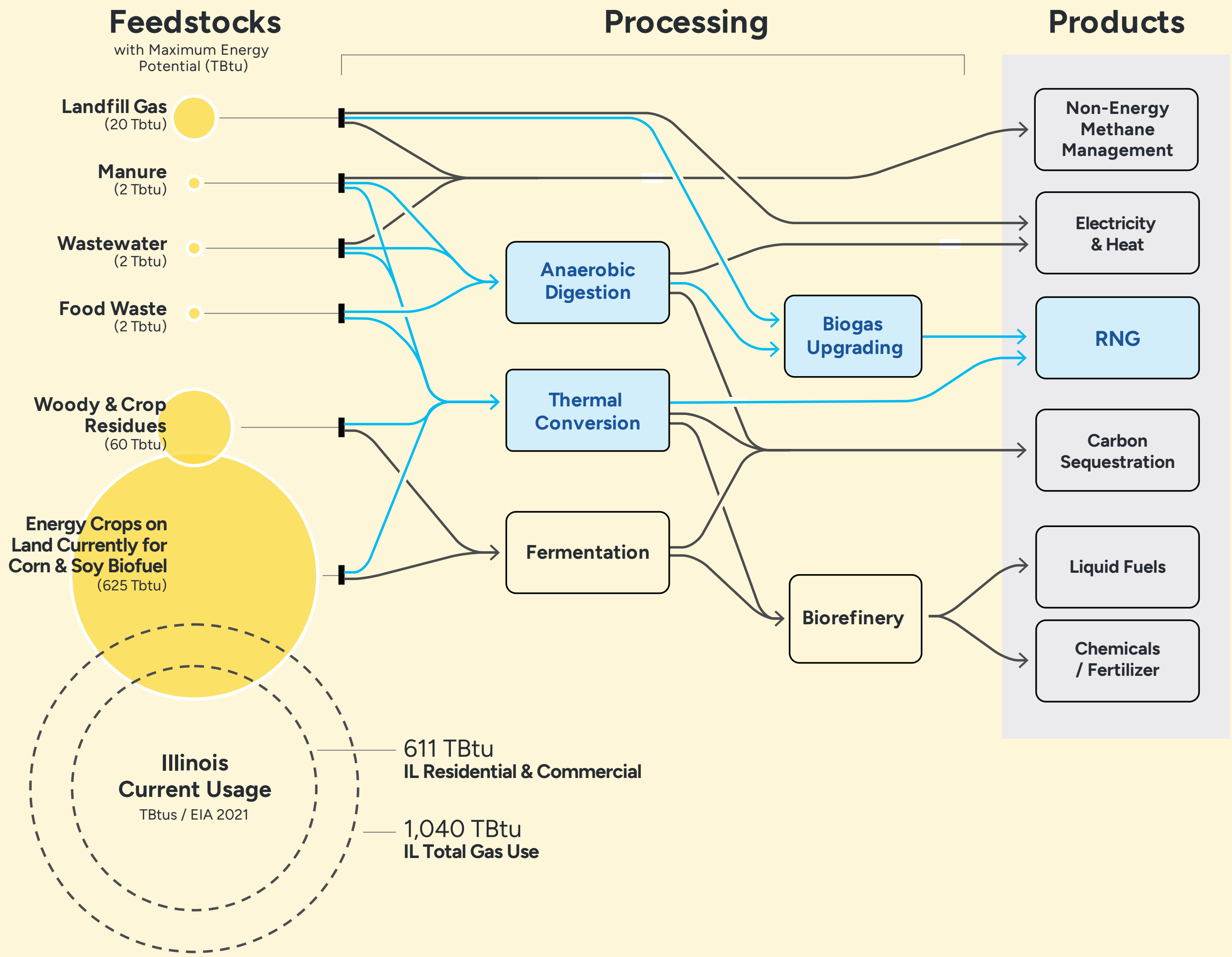
Note: Section 4 uses the term "fossil methane" or "fossil gas" to refer to geologic methane in order to distinguish it from methane produced from biomass feedstocks as defined above.

RNG has two general methods of production. The first involves the anaerobic digestion of wet biomass into biogas—a mixture of carbon dioxide (CO_2) and methane (CH_4) and some minor impurities. This biogas is then purified into pipeline-quality RNG using energy- and capital-intensive upgrading equipment. Of note, biogas can be directly converted into heat and electricity without purifying the biogas to RNG standards.

The second pathway involves heating dry biomass in the absence of oxygen to produce methane gas that then must be purified to pipeline quality and usability standards. This process is similar to how coal gas was generated in the 19th century and early 20th centuries; today it is carried out under more controlled conditions.

Figure 4.1: **Bioeconomy pathways for managing organic wastes, residues, and energy crops**

Source: Feedstock resource estimates are sourced from Groundwork's illustrative assumption that corn and soy energy crops are replaced with bioenergy crops. Values are estimates for RNG production from each feedstock and may differ for the production of other fuels.



> **“This practice is controversial because this kind of methane generation and its emissions are anthropogenic. It would be similar to offering a credit for avoided methane emissions from the capture and use of fossil gas in an oil field.”**

D. How alternative fuels influence emissions

The use of methane gas contributes to climate change in two ways: first, the combustion of fossil gas causes a net increase in CO_2 in the atmosphere; second, the extraction, transport, and use of methane gas inevitably leads to methane being leaked to the atmosphere where it has a potent, but relatively short-lived, warming effect.[131]

Alternative fuels, bioenergy, and RNG can also contribute to climate change, but where the primary impact of fossil fuels comes from the release of stored fossil carbon into the atmosphere as CO_2, the way that bioenergy influences emissions is more nuanced. The emissions impact of RNG can be broken down into three categories that, taken together, represent the total life-cycle emissions of this gas:

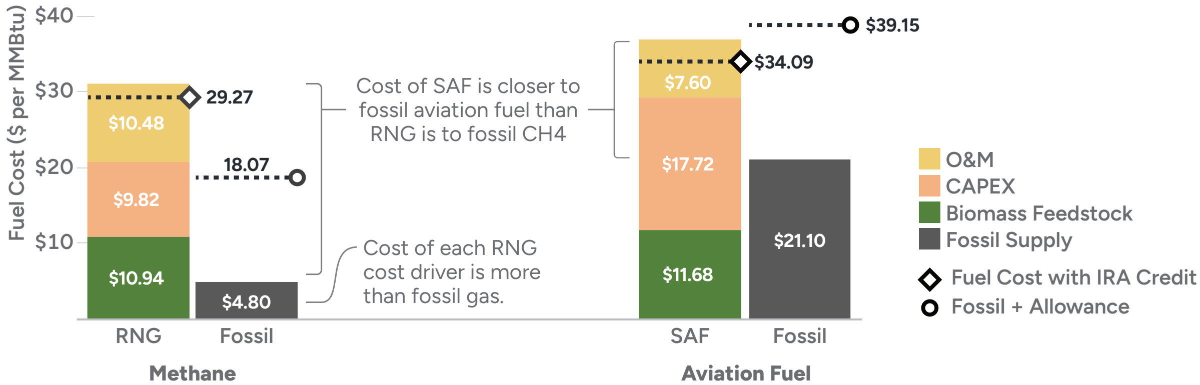
- **Process Emissions:** RNG requires the cultivation, collection, and transformation of biomass into pipeline-quality methane. This is an energy- and capital-intensive process—much more so than what is needed to produce usable fossil fuels. These energy inputs can generate emissions.
- **Methane Leakage:** Like lost fossil methane, fugitive biological or synthetic methane also represents an anthropogenic emission to the atmosphere. RNG produced from landfill gas or animal waste extends the lifetime of methane, increasing its potential to be leaked into the atmosphere relative to other management strategies.
- **Release of Carbon from Ecosystems:** Producing RNG from organic biomass that would otherwise decay does not affect the natural cycling of carbon. Alternatively, a large demand for bioenergy—driven by demand for RNG at scale—increases demand for cropland and can lead to ecosystem change that releases carbon from natural stocks thereby impacting the climate.

Thus, the life-cycle emissions intensity of RNG will vary depending on the feedstock and how the gas is processed to its end product. While life-cycle assessment (LCA) can be a useful decision support tool, policymakers should recognize that a formal LCA requires judgment calls and approximations regarding the interaction of the fuel pathways with other systems. Sometimes LCAs do not support constructive policy choices; sometimes they are even used to create misguided incentives.

The California Low Carbon Fuel Standard (LCFS) is an example of a renewable fuel standard that controversially grants a negative carbon-intensity credit to RNG pathways that use manure or food waste as feedstock. The standard assumes that the waste would have otherwise generated methane emissions and that the production of RNG avoids such emissions. This practice is controversial because this kind of methane generation and its emissions are anthropogenic. It would be similar to offering a credit for avoided methane emissions from the capture and use of fossil gas in an oil field. The use of this methodology reflected the intention of the California Air Resources Board (CARB), over a decade ago, to use LCFS transportation policy

131 CO_2 emissions cause increases in atmospheric concentrations of CO_2 that will last thousands of years. Methane (CH_4) is estimated to have a GWP of 27-30 over 100 years. Over a 20 year period, however, CH_4 has more than 80 times the warming power of CO_2. CH4 emitted today lasts about a decade on average, which is much less time than CO_2. EPA, Understanding Global Warming Potentials, https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#:~:text=CO2%20remains%20in%20the,less%20time%20than%20CO2.

Figure 4.2: Cost comparison of agricultural-derived gaseous methane and liquid sustainable aviation fuel (SAF)



Source: Groundwork Data analysis of RNG production from energy crops or waste biomass. Fossil prices are estimated from Oct 2022 to Sept 2023 EIA Illinois natural gas city gate/wholesale pipeline gas and EIA aviation fuel prices. This analysis assumes that lifecycle emissions for each biofuel are similar.

to influence manure management practices. The decision created a lucrative incentive for dairy farmers where half of the revenue produced by a cow was realized through the generation of an LCFS credit and the other half through milk production.[132] Other non-energy methane management strategies that may be more suitable are not eligible for the credit.

In December 2023, CARB proposed amendments to the LCFS to phase out such crediting.[133] However, the LCFS has unfortunately perpetuated the false notion among RNG proponents that RNG is distinctly a "carbon-negative" fuel.

There are three problems with the "carbon-negative" claim. First, there are a number of energy and non-energy strategies for managing wastes that produce methane. Such strategies should be given equal footing. Second, methane avoidance is not a source of negative emissions or removals. It simply stops the production of a potent but short-lived greenhouse gas. Third, methane-generating wastes are a limited source of RNG. Figure 4.1 above shows that such sources are a fraction (~26 TBtu) of Illinois' current gas demand (~600 TBtu).

Ultimately, policymakers need to look beyond the carbon intensity of fuel and consider how limited resources can be best directed to support decarbonization. Landfill or digester gas can be converted to renewable electricity using a fuel cell while producing a pure carbon stream that can be used for sequestration. As discussed in the next section, dry biomass is better suited to produce high-value liquid fuels that can be used in sectors that are harder to decarbonize, such as aviation.

E. RNG is expensive

RNG is uniquely expensive compared to its fossil counterpart. Where hydraulic fracturing has made methane easy to pull out of the ground, converting raw biomass to usable fuels requires substantial equipment and energy to produce. Energy crops require cultivation; food waste requires collection; manure is mostly water on a weight basis. In other words, RNG, like all bioenergy, first requires developing and collecting a feedstock, and then substantial processing to become usable energy.

Figure 4.2 compares the key cost components of RNG produced from agricultural crops ("energy crops" such as switchgrass) relative to fossil gas and, for illustrative purposes, sustainable aviation fuel (SAF). Fossil gas is relatively cheap while petroleum (e.g., fossil aviation fuel) requires more intensive extraction and refining. The high, multifold cost of RNG relative to fossil gas is notable ($31.24 vs. $4.80 per MMBtu). For RNG, the capital cost

132 Aaron Smith, "What's Worth More: A Cow's Milk or Its Poop?" (February 3, 2021), https://asmith.ucdavis.edu/news/cow-power-rising.
133 CARB, "Proposed Low Carbon Fuel Standard Amendments," https://ww2.arb.ca.gov/rulemaking/2024/lcfs2024.

> **“For RNG, the capital cost, operating expenses, and feedstock costs are each twice the cost of fossil gas.”**

(CapEx), operating expenses (O&M), and feedstock costs are each twice the cost of fossil gas.

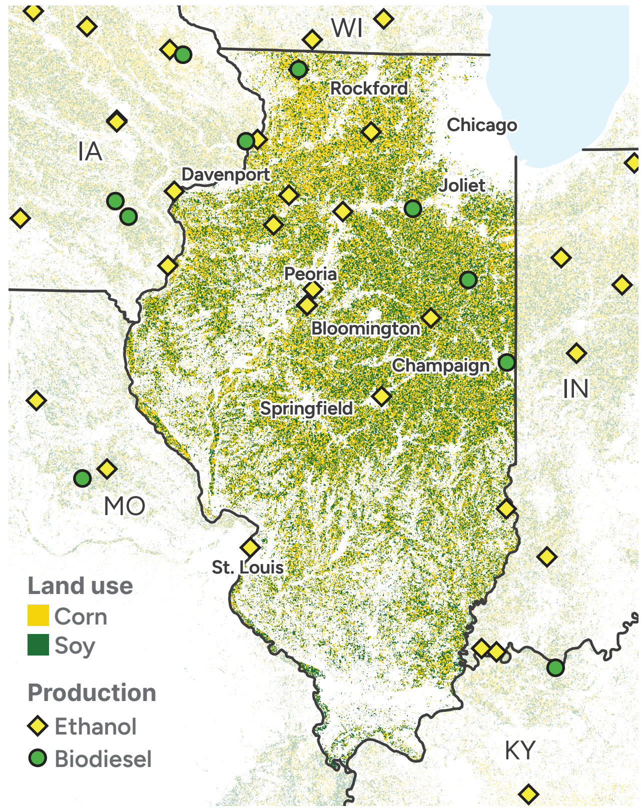
Compare this dynamic to sustainable aviation fuels (SAF) made from the same energy crop. Like RNG, SAF costs more than fossil fuels; however, the cost for a consumer to switch from fossil aviation fuel to SAF is less than the cost to switch from fossil gas to RNG. Further, IRA incentives make SAF cost-competitive with fossil aviation fuel, whereas (non-transportation) incentives for RNG fail to make RNG competitive.[134]

Another view of the high cost of RNG concerns the social cost of carbon, which monetizes the harmful societal impacts of GHG emissions attributable to fossil fuels. This social cost can be seen as a proxy for the abatement cost of the biogas or the pollution tax that should be imposed. The cost of RNG exceeds the cost of fossil gas plus its social costs, meaning that a consumer (and society) would prefer to use fossil fuels and pay for an emissions abatement rather than purchase the renewable fuel. Conversely, the social cost of fossil aviation fuel is greater than the cost of SAF, meaning that a consumer or society would prefer to use the SAF than pay for an abatement.

Ultimately, liquid fuels are more lucrative than RNG. A producer has a greater chance of making a profit on liquid fuels and would likely experience a loss if trying to sell RNG for heat in a competitive market.

F. What would it take to heat Illinois with RNG?

Figure 4.3: Illinois agricultural land use with locations of ethanol and biodiesel facilities



Source: USDA Crop Scape & EIA Biorefinery Map.

Depending on the year, Illinois’ commercial and residential buildings consume between 600-800 Tbtu of methane gas. Coincidentally, the land used for corn ethanol and biodiesel production (8.1 million acres, 35 percent of the state’s cropland) could support the production of about 625 Tbtu of RNG from gasified energy crops grown in place of corn and soybeans.

This prompts two questions for the illustrative consideration of heating Illinois with RNG.

134 Fangwei Cheng, Hongxi Luo, Jesse D. Jenkins, and Eric D. Larson. “Impacts of the Inflation Reduction Act on the Economics of Clean Hydrogen and Synthetic Liquid Fuels,” *Environmental Science & Technology* (October 17, 2023, 57 (14)), 15336–47, https://doi.org/10.1021/acs.est.3c03063.

Is the production of RNG from dedicated energy crops the best use of that cropland?

No, liquid fuels such as SAF are a higher-value commodity and can substitute for fossil fuels in a sector with high barriers to electrification, such as aviation. The cost analysis above (in Section 4.E) shows that:

1. Under market conditions, RNG is far less competitive than liquid fuels.
2. Liquid fuels have a lower emissions abatement cost.
3. Federal incentives for bioenergy resources prioritize transportation fuels and carbon sequestration over building heat. As a result, greater subsidies exist for these fuels than RNG, thereby increasing the clearing price that a customer (or ratepayer) needs to pay to buy RNG.

Ultimately, efforts to blend RNG into the gas supply will face considerable challenges because of competition from other uses of bioenergy feedstocks.

Is RNG the best strategy for heating homes and businesses at scale?

No, RNG has cost and scalability challenges:

1. RNG blending will increase customer costs significantly. This will further incentivize customers to leave the gas system.
2. RNG offers customers no new value proposition beyond compliance with voluntary and future policy-based emissions targets. For customers remaining on the gas system, there are likely to be more cost-effective avenues for achieving compliance.
3. The assumption that pipeline gas can be decarbonized by using RNG may lead some entities to delay electrification and lock in new gas infrastructure.

Heating electrification allows local heat to be harvested from the air, water and earth surrounding a building. While complementary investments in local buildings and local clean energy are often needed, for Illinois, heating electrification displaces fossil fuel imports from out of state while allowing the state's bioenergy economy to continue to export higher-value energy. Alternatively, while using RNG at scale may displace fossil fuel imports, RNG offers no consumer benefits (i.e., it fails to address the air quality and health risks of combusting gas) and it compromises Illinois' bioenergy export opportunities.

Energy transition researchers and practitioners have demonstrated that several factors will significantly constrain the ability of RNG to play a meaningful role in achieving global, national, and state net-zero targets. These include physical limits on the state's bioenergy resources, competing demand for bioenergy resources from other sectors, and the relatively high cost of producing pipeline-compatible RNG. The Princeton University Net-Zero America Study best illustrates this perspective, but it has also been explicitly demonstrated in an analysis of the economics of alternative fuels as well as in Massachusetts.[135] Additionally, the findings are corroborated by multi-model, multi-pathway comparisons and established principles of decarbonization that emphasize the use of renewable fuels in hard-to-electrify sectors such as aviation.[136]

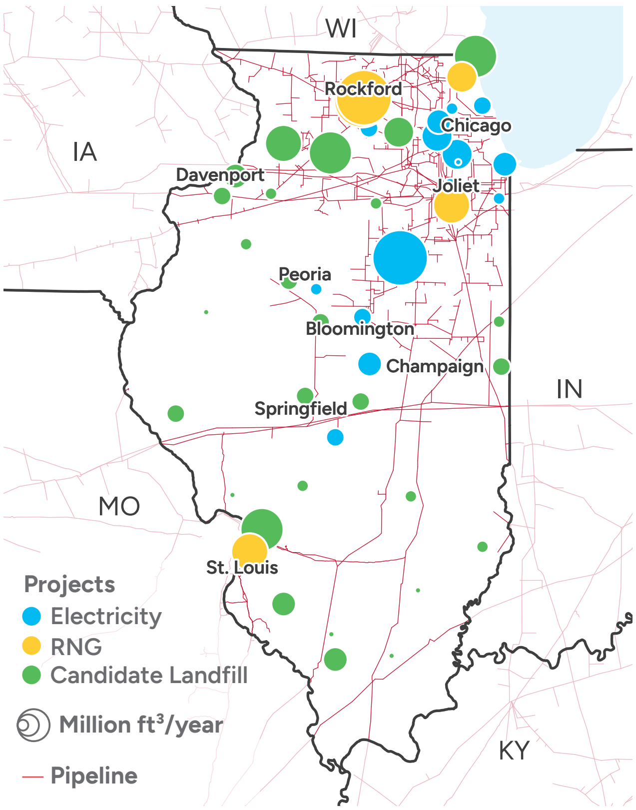
135 Princeton University, Net-Zero America (October 2021), https://netzeroamerica.princeton.edu/; Gabe Kwok, "Low Carbon Fuels in Net-Zero Energy Systems" (August 1, 2022), Evolved Energy Research, https://www.evolved.energy/post/low-carbon-fuels-in-net-zero-energy-systems; and Ryan Jones et al., *Massachusetts 2050 Decarbonization Roadmap: Energy Pathways to Deep Decarbonization*, Evolved Energy Research (2020), https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download.

136 Morgan Browning et al. "Net-Zero CO_2 by 2050 Scenarios for the United States in the Energy Modeling Forum 37 Study," *Energy and Climate Change* (December 1, 2023, 4), 100104, https://doi.org/10.1016/j.egycc.2023.100104 and Inês Azevedo et al., "Net-Zero Emissions Energy Systems: What We Know and Do Not Know," *Energy and Climate Change* (December 2021,2), 100049, https://doi.org/10.1016/j.egycc.2021.100049.

G. Current RNG projects in Illinois face steep challenges and high costs

> **"The cost of RNG produced by these projects is likely to range from $12.50 per MMBtu (optimistic for a landfill) to over $25 per MMBtu (food waste)—far above the $3-$6 range of fossil gas in recent years."**

Figure 4.4: Current and pending RNG projects in Illinois



Source: EPA Landfill Methane Outreach Program (LMOP).

Several RNG projects have emerged in Illinois in the last few years and each appears to be taking advantage of incentives for transportation fuels. These projects largely seek to produce methane from wet wastes: food waste in landfills, collected food waste, animal manure, and sludge from wastewater treatment plants.

Landfills in Illinois have been producing electricity and heat from raw landfill gas since the 1980s. It was only in 2015 that the Milam Recycling and Disposal Facility (East St. Louis) started producing RNG for vehicle fuel, obtaining credits from the California LCFS. In 2022, the Prairie View facility in Wilmington invested $46 million to switch from producing electricity to producing RNG. There are at least three more facilities under construction or planned.[137] Currently, approximately 12.5 percent of collected landfill gas in Illinois is upgraded to RNG.

Such projects fail to capture all the methane produced by a landfill. Ideally, food waste would not be sent to the landfill from the start. This is the intent of projects such as the $32 million Green Era Campus in Auburn-Gresham, an urban farm in Chicago's South Side that collects and digests local food waste to produce fertilizer and RNG for injection into the Peoples gas distribution network. The project has received international attention for its efforts to prioritize local community needs as part of its development.

The cost of RNG produced by these projects is likely to range from $12.50 per MMBtu (optimistic for a landfill) to over $25 per MMBtu (food waste)—far above the $3-$6 range of fossil gas in recent years. While details on such projects are scarce, it is likely that these projects are only financially feasible due to the availability of Renewable Fuel Standard (RFS) and LCFS credits for the production of RNG for use in vehicles only.

Alternatively, such projects could and may be directed toward other strategies. Advances in fuel cell technology have allowed biogas to be efficiently transformed into electricity at low cost while producing a concentrated CO_2 waste stream. The

137 U.S. EPA, OAR "LMOP Landfill and Project Database," (April 20, 2016), https://www.epa.gov/lmop/lmop-landfill-and-project-database.

IRA offers incentives for capturing that CO_2 while proposed changes to the RFS and LCFS may make electric generation more favorable. Such clean electricity is beneficial for Illinois and could play a role in achieving CEJA's renewable energy targets and providing additional power to meet the State's growing electricity demand. A biogas-to-fuel-cell and electric-to-heat-pump pathway can generate twice as much heat at lower overall cost than a biogas-to-RNG-to-furnace pathway.

Emerging liquid fuel (e.g., SAF) pathways may be more effective for managing wet wastes by reducing the footprint of various waste management practices. They also may have the potential for destructing PFAS and other contaminants, an increasingly important and expensive issue for public wastewater treatment plants.

H. RNG regulation and utility programs in Illinois

In Illinois, legislative proposals to blend RNG into utility gas supply seek to emulate clean electricity portfolio standards. For example, in the 2023 legislative session, HB3115 would have required gas utilities to blend in RNG, hydrogen, or synthetic methane to volumetric levels of 2 percent and 3 percent of the gas supply by 2030 and 2035, respectively. The bill also empowered the ICC to incorporate such fuels into its portfolio based on cost-effectiveness, reliability, and emissions reductions. The Act failed to advance.[138] Unlike clean electricity standards, an RNG standard would significantly increase customer costs due to RNG's cost premium.

Gas utilities in Illinois have begun to introduce voluntary programs that allow customers to pay a premium for the purchase of carbon offsets and investment in RNG. For example, Nicor's "TotalGreen" voluntary program, launched in 2022, allows Nicor customers to "balance" their fossil gas-based carbon footprint with a mixture of RNG attributes and "Illinois-Sourced" carbon offsets.[139] Nicor defines its offsets as "planting of trees, carbon sequestration, or destructing methane before it escapes into the atmosphere."[140] Customers can choose between a Basic ($0.0734 per therm) and a Premium package ($0.2646 per therm) consisting of 0.6 percent and 10.3 percent RNG attributes with remaining consumption balanced by offsets. Such an approach obscures the true cost of RNG, which is on the order of $2 per therm or four times current fossil gas supply prices. At these prices, substituting RNG for fossil gas would double the cost of a delivered therm of methane on a typical bill. Like the increasing costs of fossil gas delivery that we model in the next section, higher supply costs for RNG-blended fossil gas will incentivize customers to leave the gas system.

> **"At these prices, substituting RNG for fossil gas would double the cost of a delivered therm of methane on a typical bill."**

The low levels of RNG offered in TotalGreen, and the need to blend in offsets to make the voluntary program seem impactful, emphasize another point. The same biomass used to produce RNG can also be used to generate a net removal of CO_2 through pathways that could be higher quality than the "offsets" included in Nicor's TotalGreen program. For example, instead of producing biogas from wet wastes or gasifying dry biomass, such feedstock could be thermally converted into a bio-oil and pumped underground, likely at a lower cost than

138 Illinois General Assembly, "Renewable Gas and Low Carbon Fuels Act" HB3115, 2021. Session Sine Die as of 2023 ilga.gov/legislation/BillStatus.asp?DocTypeID=HB&DocNum=3115&GAID=16&SessionID=110&LegID=132039.

139 See https://www.nicorgas.com/sustainability/totalgreen/carbon-emissions-mgmt.html and ICC, Docket No. 21-0098, Nicor Gas Ex. 11.0R, icc.illinois.gov/docket/P2021-0098/documents/309549/files/539516.pdf.

140 The reader should note that many such practices, even when verified, are ineffective and possibly counter-productive for achieving stated climate goals. In addition, programs should detail their RNG attributes and comprehensively describe protections to be taken to ensure the quality of offsets.

the cost to produce RNG.[141] Hypothetically, an emissions credit created by such removal and used to allow the use of fossil gas would generally have the same net emissions impact as using RNG—again produced from the same biomass at a lower cost and energy demand.

The Illinois Attorney General (AG) touched upon another weakness of the TotalGreen Program, describing the program as a vehicle for customers to buy environmental attributes. The AG questioned why a utility should sell these attributes when they are already available on the market. Moreover, Nicor's inability to offer a 100 percent RNG product emphasizes the limitations on scalability. From a cost perspective alone, RNG faces steep scaling challenges.

Other gas utility RNG-focused programs in Illinois pertain to pilot projects that allow the utilities to introduce RNG into their service territories through an interconnection between RNG producers and the company's distribution system. Both Nicor and Peoples have such pilots underway. In addition, effective April 2023, Peoples has been allowed to create a rider called "Rider PRG: Producer of Renewable Gas Transportation Service" that allows a provider of RNG to deliver RNG into Peoples' distribution system for use and consumption by the company's gas transportation customers located in Peoples' service territory.

These legislative proposals and nascent utility programs underscore the need for the ICC to determine what regulatory principles will guide the role of RNG, if any, in the gas distribution system. Should gas utilities be permitted to add renewable gas options to their resource portfolios and develop procurement strategies? Should gas utilities be able to update their forecast and supply planning standards to incorporate RNG either through direct blending or the use of RNG attributes? Should customers have options to purchase RNG from either the gas utility and/or from third-party suppliers? Answers to these regulatory questions require deep technical analysis of the emissions and resource demands of different RNG pathways, and whether sufficient RNG stocks will be available to ensure the potential environmental benefits. For now, it is clear that RNG does not meet a least-cost supply planning standard, given the high cost of RNG relative to pipeline gas.

Many of the questions surrounding RNG and what constitutes an emission reduction would most usefully be addressed outside the regulation of the gas system. Illinois is potentially one of the most bioenergy rich states in the U.S. because of its significant cropland resources that can be used to grow energy crops. Determining the highest and best use of Illinois' potential bioenergy capacity requires broad sectoral planning that extends beyond the ICC's regulatory purview.

As Illinois considers the future of gas, policymakers should recognize the difficult limitations on replacing fossil gas with alternative fuels. The question, "should the future of heat be electric or fueled by RNG," is a misdirection. Electrification is more scalable. Even when gas serves a transitional role in supporting electrification, our analysis of RNG's costs shows that producing RNG is a misuse of limited bioenergy resources.

I. Hydrogen faces similar barriers to RNG as a source of clean heat

Proposals to decarbonize utility gas have also included proposals to blend hydrogen into existing distribution networks or to establish new exclusively hydrogen-fed distribution networks. There are several challenges associated with these strategies.

Currently, hydrogen is produced from fossil fuels for about $2 per kg (roughly equivalent to $16 per MMbtu), or three-times the current cost of fossil gas. The cost of producing hydrogen from renewables is currently estimated to be over $5 per kg. However, the U.S. Department of Energy has set aggressive cost targets of $2 per kg by 2026 and $1 per kg by 2031. Lucrative subsidies from the Inflation Reduction Act (IRA) may make hydrogen available at those costs sooner. However, much depends on federal rulemaking for those subsidies, which is still

141 Emily Pontecorvo, "Meet the Startup Producing Oil to Fight Climate Change," *Grist* (May 18, 2021), https://grist.org/climate-energy/lucky-charm/.

> **“Currently, hydrogen is produced from fossil fuels for about $2 per kg (roughly equivalent to $16 per MMbtu), or three-times the current cost of fossil gas.”**

in development, and how fast the industry can scale. Hydrogen may emerge as a cheaper, and possibly more scalable strategy than RNG, but it will still put upward pressure on consumer energy costs.

Hydrogen also faces significant practical, safety, and emissions challenges.[142] Existing gas networks are largely incompatible with hydrogen. Hydrogen is corrosive to several different pipeline materials and is known to have a degrading effect on fittings, valves, joints, and welds. Furthermore, as the hydrogen blend increases, end-use appliances may require modification. Other concerns include: safety (hydrogen is more hazardous than fossil gas); leakage rates (because hydrogen is a small molecule, leak rates from distribution pipes will increase); and the need to increase operating pressures which in turn will increase leak flow rates (hydrogen has only one-third the energy content of methane and, therefore, greater pressure is required to deliver the same amount of energy). Addressing these challenges will increase the need for long-term system investment which, in turn, will push up customer rates, adding to the already substantial cost challenges of the existing gas system.

While gas utilities in the U.S. have announced several hydrogen projects to deliver blended gas to gas distribution systems, the vast majority of hydrogen investment activity across the country is focused on end uses other than heat. Notably the Midwest Hydrogen Hub (MachH2),[143] which includes the states of Illinois, Indiana and Michigan, does not emphasize the role of hydrogen for heat in its promotional materials. It focuses instead on the potential role of hydrogen in steel and glass production, agriculture, power generation, heavy-duty transportation, and sustainable aviation fuels. Low-carbon hydrogen has an important role to play in decarbonizing existing hydrogen markets, such chemical feedstock, ammonia, and high temperature heat. Such uses should be considered priority applications for hydrogen given the limited decarbonization pathways for these uses.

142 Jan Rosenow, “Is heating homes with hydrogen all but a pipe dream? An evidence review,” *Joule* (2022, 6(10)), https://doi.org/10.1016/j.joule.2022.08.015.

143 MachH2 is the Midwest Alliance for Clean Hydrogen, a consortium of state, industrial, and academic partners committed to growing Midwest regional hydrogen. In 2023, the consortium was funded by the U.S. DOE to develop a Regional Clean Hydrogen Hub. See: https://machh2.com/.

Section 5

Cost Analysis for the Future of Gas in Illinois

A. Key takeaways

- The market valuation of Illinois' gas utilities and the future financial obligations of ratepayers will be powerfully shaped by two key variables examined in our modeling: gas system capital expenditures and customer departures due to the takeup of new energy technologies. Understanding the sensitivity of Illinois' gas system to changes in these two variables is critical for policymakers and regulators guiding the transition.
- If current capital expenditure levels of approximately $1.5 billion per year continue, total capital spending by 2050 would amount to $99 billion across the Big Four gas utilities, resulting in cumulative gas system costs of approximately $169 billion (the latter amount includes direct capital expenditures but also operations and maintenance, return to investors, and property taxes).
- By 2030, current capital spending levels would require a 45 percent increase in the combined revenue requirement of the Big Four gas utilities, even if the gas customer base remains stable. If rate cases were to occur annually, then over the next six years customer rates would need to increase 8 percent each year to manage the increasing costs of the gas system.
- As more customers move away from the gas system, the challenge of increasing delivery costs will intensify, leaving fewer customers to bear the cost burden. Roughly a decade from now, continued business-as-usual spending accompanied by *moderate* customer departures would more than double average delivery costs per customer for each gas utility. *High* customer departures cause average delivery costs to roughly triple by 2035.
- Controlled spending now can modulate and even substantially reduce ratepayer burden beyond the 2030s. Flat rather than increasing levels of capital spending significantly reduce average delivery charges per customer, even with moderate levels of customer decline.
- However, because high levels of prior capital spending have been baked into the rate bases of each utility, delivery costs now and in the future are burdened by the strong "undertow" effect of prior cost recovery decisions. Thus, even assuming a best-case scenario of flat capital spending with moderate customer departures, by the mid- to late-2030s average delivery costs per customer still double for each gas utility.
- Assuming only moderate customer departure by 2030, the implied gas customer rate increases would be unprecedented for Illinoisians and would give ratepayers a strong incentive to leave the gas system for other energy alternatives. Ensuing ratchet effects are quite possible,

speeding up customer departures even further and leaving remaining gas customers shouldering even higher gas rates in the negative feedback loop of an unmanaged transition. Since leaving the gas system often requires out-of-pocket expenditures to convert to new space and heating technologies, those staying put are most likely to be lower-income households or renters.

- Illinois potentially faces a substantial stranded gas asset problem that is likely to negatively impact the market valuation of the state's gas utilities. By 2050, if current capital spending levels continue, the Big Four gas utilities would have accumulated more than $80 billion in unrecovered book value—a sixfold increase. Reduced levels of capital spending now are essential to lower the risk of high unrecovered balances.

B. Introduction

This section investigates what the future of gas holds for ratepayers and utilities in terms of the costs of the gas system. If utilities continue their current levels of investment in their gas systems, how are delivery costs per customer likely to change? And, how would a declining customer base due to an increase in building electrification affect costs for remaining ratepayers as well as the general financial stability of the utilities?

To investigate these questions, we model a set of cost scenarios in which we vary two key variables: gas plant capital spending and customer departures. Our modeling relies on utility data filed with the ICC and on the latest authorized financial variables set by the Commission in its 2023 rate case orders.

C. Methodology

Our analytical model consists of four steps:

1. **Developing capital cost and rate base projections for each company.** Ideally, projections for future capital plant additions would draw directly from each company's stated long-term capital plans. However, such detailed planning reports have not been required by the ICC, with the exception of Peoples' System Modernization Program.[144] The lack of company capital expenditure (CapEx) forecasts is a notable gap, considering the multi-decade spending on long-lived assets that each gas utility appears to be pursuing. The ICC's recent decision to mandate biennial long-term planning reports from utilities starting in 2025 is a positive development. In the absence of these reports, we use data on plant additions obtained from utility filings with the ICC to examine historical trends in plant additions.
2. **Estimating the annual revenue requirement needed to cover each gas utilities' capital spending plus related capital costs and operating expenses.** As described in Section 3.F, the revenue requirement refers to the annual amount of revenue that a utility must realize through its customer billing in order to cover its operating expenses and capital costs. We rely on the Commission's 2023 rate case orders and related rate case filings to determine values for the various components constituting required revenue (see Appendix A: Modeling Methodology).
3. **Estimating the customer bill impacts of various capital investment and customer base scenarios.**[145] Using our annual revenue requirement projections, we calculate the estimated per customer revenue requirement (i.e., the total revenue requirement in each year divided by the total customer base) and use this as a consistent, normalized metric

144 Peoples files quarterly reports for its System Modernization Program that detail its capital spending planning (available at https://www.icc.illinois.gov/programs/natural-gas-investigations). For the now terminated Qualified Infrastructure Program (QIP), annual plans had to be filed each year by participating gas utilities but these reports gave little historic or prospective information.

145 Modeling of the customer rate impacts of continued gas utility capital spending was provided by Synergen during the 2023 rate case proceedings. Strategen modeled what would happen to customer rates if the ICC approved the requested rate base and revenue requirement and then assumes capital expenditures continue at their trend rate. GWD relies on the rate base, cost of capital, and other variables authorized by the ICC at the conclusion of the rate cases and provides sensitivity analyses related to customer departures and different levels of capital spending. The two sets of analyses are directionally aligned in finding that customer bills are on an unsustainable path and that electrification will have pronounced negative gas bill impacts.

for assessing the bill impact for ratepayers.[146] (We also refer to this metric as the average utility delivery cost to serve a gas customer, or the average cost of delivery for short.[147]) For Illinois' Big Four, between 66 percent and 75 percent of each company's annual revenue requirement is paid for by residential customers; another 16 to 20 percent is paid for by small and intermediate business customers ("commercial customers"). Furthermore, residential customers make up the vast majority of customers—in excess of 90 percent.

4. **Calculating the value of unrecovered gas plant balances ("book value") for each gas utility at different points in time.** An unrecovered balance refers to gas assets that have been put into service but not yet fully paid back via customer rate payments (i.e., the assets have not been fully depreciated). Regulators and future of gas proceedings across the country are identifying the prospect of stranded gas assets as a top concern. The purpose of this calculation is to understand overall rate recovery progress—that is, progress toward full recovery of all current and prior gas plant investments. As the energy transition proceeds, an increasing number of gas assets will become underutilized and possibly no longer "used and useful," but their cost recovery will not be completed.[148] An example would be the distribution main, services, and meters on a street segment where all of the gas customers have left the gas system after installing more efficient space and heating equipment. Our analysis probes the magnitude of gas assets in Illinois at risk of being stranded as the transition advances and the impact that further capital spending has on that risk. We group our modeling findings on this topic in Section 5.F.

146 An alternative approach is to estimate the future customer billing rates (gas supply charge plus fixed and variable delivery charges) that will be developed through the regulatory ratemaking process.

147 Steven Nadel, *Impact of Electrification and Decarbonization on Gas Distribution Costs* (June 2023, Washington, DC: American Council for an Energy-Efficient Economy), p. 5, https://www.aceee.org/research-report/u2302.

148 Kristin George Bagdanov, "The Future of Gas: A Summary of Regulatory Proceedings on the Methane Gas System," DecarbNation Blog, Building Decarbonization Coalition (December 15, 2022), https://building-decarb.org/decarbnation-issue-2#scope.

D. Reference case: Continuing the gas system as usual

We first model a Reference Case that assumes:

- A steady customer base with no gas customer defections due to electrification or other non gas-pipeline alternatives
- Continued steady-state capital investment at 6 percent per year

The selection of a 6 percent rate of growth in capital spending is based on our trend analysis of prior expenditures for each gas utility and is on the lower end of actual gas plant capital spending trends.[149] It is also consistent with the fact that three of the four gas utilities are squarely in the midst of major long-term infrastructure plans (see Section 3.I for details).

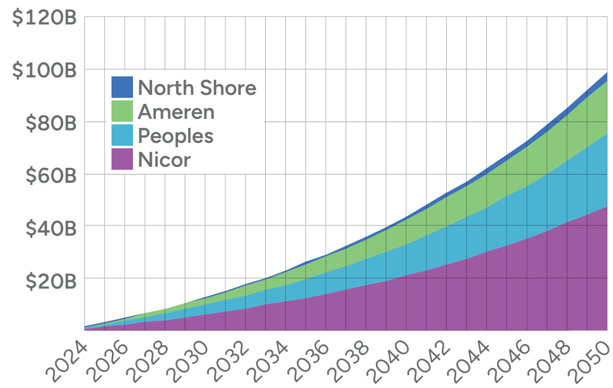
The Reference Case reflects a counterfactual world with no GHG goals or climate-related policies, no technological innovation resulting in efficient, cost-effective, non-gas options for heating and cooling buildings, and no interest and/or capacity on the part of regulators and policymakers to steer the gas system in a socially optimal direction using standards, accountability, and incentives.

Findings: Total CapEx

Assuming that gas plant CapEx rises by 6 percent per year, we project that *annual* capital additions to the gas system as a whole will increase from $1.5 billion in 2024 to $7 billion in 2050, for a cumulative total of $98.6 billion to be invested in the Illinois gas system over the next 25 years (see Figure 5.1 where the area under the lines equals $98.6 billion).

149 See Appendix A for details on historical capital spending trends and on how 2024 capex levels were adjusted to take into account the capital disallowances ordered by the ICC in the gas utilities' 2023 rate cases.

Figure 5.1: Total Reference Case cumulative CapEx, 2024-2050



Source: GWD modeling of utility capital spending based on historic spending patterns

Table 5.1 breaks down the projected capital additions by gas utility, focusing on the beginning and the end of the time period under consideration, i.e., 2024 and 2050.

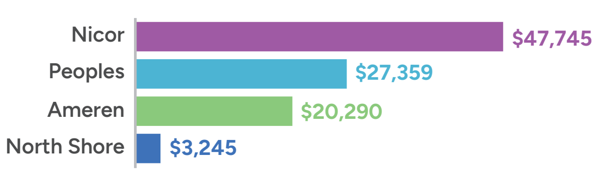
Table 5.1: Reference Case CapEx, 2024 and 2050 (million $)

Year	2024	2050
Ameren	$318	$1,449
Nicor	$749	$3,410
North Shore	$51	$232
Peoples	$429	$1,954
Total	**$1,548**	**$7,044**

Source: GWD modeling of utility capital spending based on historic spending patterns

Over the next 25 years, Nicor would account for nearly 50 percent of total CapEx ($47.7 billion) followed by Peoples at 28 percent, Ameren at 21 percent, and North Shore at 3 percent (see Figure 5.2).

Figure 5.2: Reference Case cumulative CapEx, 2024-2050 (million $)



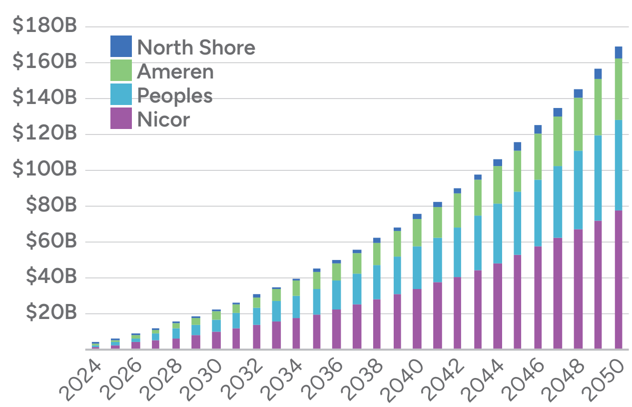
Source: GWD modeling of utility capital spending based on historic spending patterns

> **“Gas customers today are responsible for paying only 1.5 percent of the revenue requirement they theoretically would be on the hook for in 2050.”**

Findings: Total cumulative revenue requirement by 2050[150]

As shown in Figure 5.3, considering all four gas utilities together, the Reference Case results in extraordinary annual revenue requirements for the Big Four gas utilities. By 2030, the combined annual revenue requirement of the four utilities increases by 45 percent over its 2024 level. By 2050, the cumulative revenue requirement totals $169 billion, or 68 times the 2024 revenue requirement of $2.5 billion. This means that gas customers today are responsible for paying only 1.5 percent of the revenue requirement they theoretically would be on the hook for in 2050.

Figure 5.3: Total cumulative revenue requirement for the 4 gas utilities, 2024-2050



Source: GWD modeling of utility revenue requirement

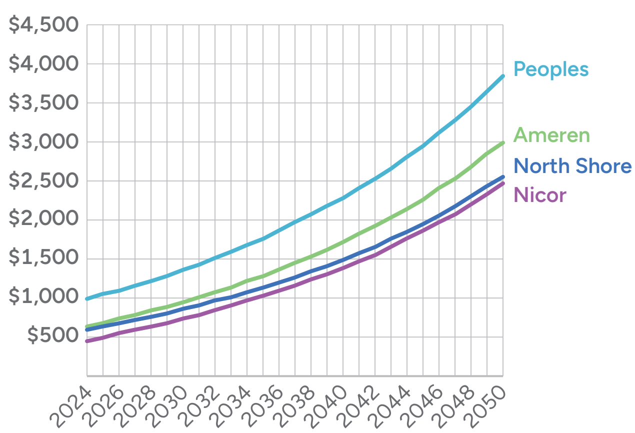
150 Figures are expressed in nominal dollars as inflation can be assumed both for the value of the dollar and for increasing costs to labor and materials for pipeline replacement.

Findings: Average utility delivery cost per customer

Our next consideration is the impact of Reference Case capital spending on customer bills. We measure this bill impact as revenue requirement per customer (i.e., average delivery cost per customer). Figure 5.4 shows the change in revenue requirement per customer from 2024 to 2050 for each gas utility under the Reference Case. Note that the starting "base year" revenue requirements per customer vary considerably. The average annual cost of providing delivery services to a gas customer ranges from a low of $453 for Nicor to a high of $994 for Peoples. North Shore has the second-lowest average cost at $595 and Ameren's average cost is $630.

Assuming the state's Big Four continue their capital spending on a business-as-usual (BaU) trajectory, by 2030, the utilities would need a 45 percent increase in their average per customer revenue requirement to pay for these increased delivery costs, even if the gas customer base remains stable. By 2035, the average per customer revenue requirement nearly doubles from its 2024 level (94 percent increase). Should rate cases occur annually, then over the next six years (until 2030), customer rates would need to rise by approximately 8 percent each year to manage the increasing costs of the gas system.

Figure 5.4: Reference Case projected annual revenue requirement per customer, 2024-2050



Source: GWD modeling of utility revenue requirement

Using 2024 as the base year, our company-specific findings are as follows:

- **Ameren:** By 2030, revenue requirement per customer increases by 46 percent, from $630 per customer to $945. By 2035, the rate burden doubles, and by 2050, it increases nearly five times.
- **Nicor:** By 2030, revenue requirement per customer increases by 61 percent, from $453 per customer to $729. The rate burden doubles by 2035 and more than quintuples by 2050.
- **North Shore:** Revenue requirement per customer increases by 43 percent in 2030, from $595 per customer to $852. By 2035, it increases by 90 percent and then more than quadruples by 2050.
- **Peoples:** By 2030, revenue requirement per customer increases by 37 percent, from $994 per customer to $1,358. By 2035, it increases by 80 percent, and by 2050, it nearly quadruples. Peoples' rate burden surpasses $1,000 per customer five to ten years before the other gas utilities because this utility starts out with the highest average cost of delivering services.

The scale of the above customer rate burdens would be unprecedented for Illinoisians and would likely give ratepayers a strong incentive to leave the gas system for other energy alternatives. We capture that dynamic in the next section by modeling several scenarios related to electrification.

E. Scenarios incorporating gas capital spending discipline and electrification

We next consider three sets of scenarios that explore what happens to the costs of Illinois' gas system when customers depart the system and/or when capital spending is either kept constant or declines in tandem with customer departures. Specifically:

- For customer departures, we consider two alternatives: moderate customer decline that results in 50 percent of customers leaving the system by 2050 and high customer decline resulting in 90 percent of customers leaving by 2050. For each treatment, we assume a linear decline in the number of customers leaving the system year-over-year.[151]
- For changes in utility capital spending, we consider three treatments: business-as-usual spending, as in the Reference Case where spending increases 6 percent year-over-year; a flat spending scenario, where annual capital spending (CapEx) is fixed at 2024 levels; and a declining CapEx scenario where CapEx decreases in line with decreasing customer counts. Flat and declining CapEx could result from policies that avoid pipeline replacement and line extensions, instead relying on non-gas pipeline alternatives, strategic pipeline retirement, and advanced leak detection and repair.

The various treatments for customer departures and spending and how they relate to each scenario are summarized in Table 5.2. In the following subsections, we present the results from each scenario.

151 The 50% customer decline is achieved by applying a 1.9% annual decline based on the 2024 customer count, beginning in 2024. The 90% decline is achieved by applying a 3.5% annual decline based on the 2024 customer count, beginning in 2024.

Table 5.2: Modeling scenario descriptions

	Customer count	
CapEx With Customer Departures	**Moderate decline** 50% reduction by 2050	**High decline** 90% reduction by 2050
Business-As-Usual (6% annual increase)	Scenario 1	Scenario 2
Flat (at 2024 levels)	Scenario 3	Scenario 4
Declining (in line with customer departures)	Scenario 5	Scenario 6

See Section 5.H (page 79) for detailed figures presenting the scenario modeling results by company.

Business-as-usual CapEx with customer departures: Scenarios 1 and 2

Of the six scenarios we model, Scenarios 1 and 2 involve the highest continued levels of capital spending: BaU capital spending with a 6 percent increase each year. They therefore generate the highest levels of per customer revenue requirements as customers depart the gas system.

Findings: Total CapEx

Scenarios 1 and 2 follow the same spending paradigm as the Reference Case. As mentioned above, this level of spending results in cumulative spending of $98.6 billion by 2050, with annual CapEx rising from $1.5 billion in 2024 to $7 billion in 2050. Nearly 50 percent of total spending occurs in Nicor's territory (see Figures 5.1 and 5.2 and Table 5.1, above).

Findings: Total cumulative revenue requirement by 2050

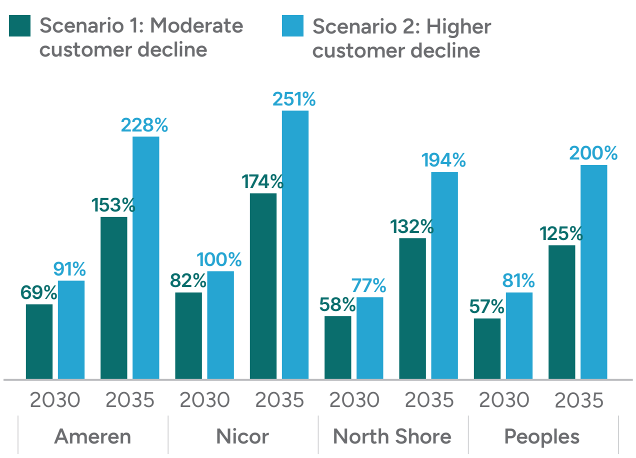
Customer departures have a relatively small impact on the cumulative revenue requirement described in the Reference Case since that requirement is largely driven by capital and operational spending. Customer departures reduce the cumulative revenue requirement by roughly 3 percent—or around $5 billion—compared to the Reference Case.

Findings: Average utility delivery cost per customer

Assuming moderate customer decline (Scenario 1), by 2030, average delivery costs increase by 57 to 58 percent for Peoples and North Shore, and up to 69 to 82 percent for Ameren and Nicor (see green bars for 2030 in Figure 5.5). Roughly a decade from now, the rate burden increases range from 125 to 174 percent (see green bars for 2035 in Figure 5.5).

High customer departures (Scenario 2) cause average delivery costs to accelerate even more since total costs are being spread over a small customer base. By 2035, the increases range from 193 to 251 percent across the four companies (see blue bars for 2035 in Figure 5.5).

Figure 5.5: BaU CapEx with customer departures—Percent increase in average delivery cost from 2024 to 2030/2035 by gas utility



Source: GWD modeling of utility revenue requirement

Roughly a decade from now, continued spending accompanied by moderate customer departures more than doubles average delivery costs for each gas utility. The increase ranges from 125 to 131 percent for Peoples and North Shore, and from 153 to 174 percent for Ameren and Nicor. High customer departures cause average delivery costs to more or less triple by 2035.

Flat CapEx with customer departures: Scenarios 3 and 4

Scenarios 3 and 4 explore the effect of flat capital spending with moderate and high levels of customer departures.

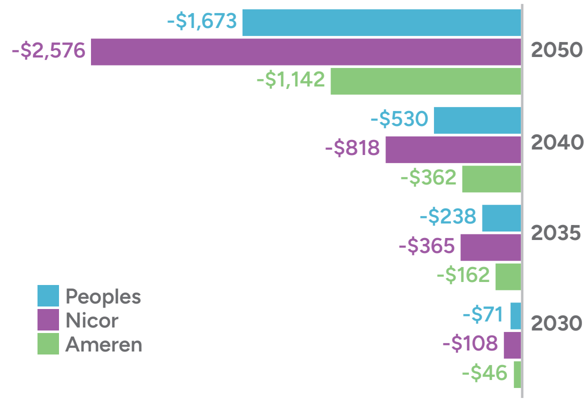
Findings: Total CapEx

Imposing the discipline of flat CapEx to gas utility capital spending beginning in 2024 essentially cuts total CapEx by 58 percent by 2050. For example, instead of spending $48 billion by 2050, Nicor would spend $20 billion. Ameren would spend $9 billion instead of $20 billion. Peoples would spend $12 billion instead of $27 billion.

Findings: Total cumulative revenue requirement by 2050

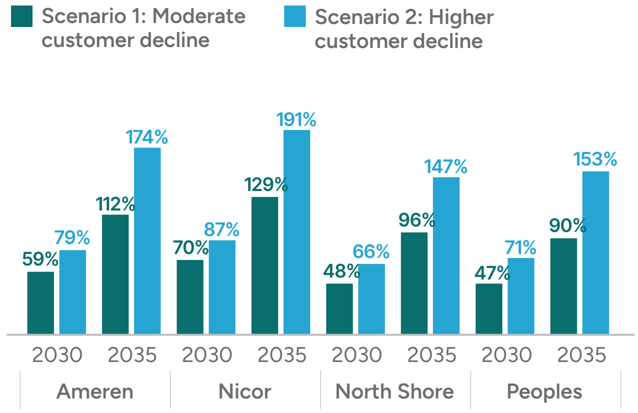
Flat CapEx can have a considerable impact on the long-term cost challenge of the gas system. Compared to the Reference Case and assuming moderate customer departures, level spending on gas infrastructure lowers the cumulative 2050 revenue requirement cost by 31 percent, or $52 billion, reducing the amount from approximately $170 billion to $116 billion. Figure 5.6 breaks this cumulative impact down to show the impact of level capital spending (assuming moderate customer decline) on the annual gas revenue requirement of the three largest companies. By 2030, the annual revenue requirements of the three largest companies would be reduced by $46 to $108 million; by 2050, these reductions would range from $1.1 to $2.6 billion.

Figure 5.6: Reductions in annual revenue requirement due to flat CapEx by gas utility with moderate customer decline, 2030-2050



Source: GWD modeling of utility revenue requirement

Figure 5.7: Flat CapEx with customer departures—Percent increase in average delivery cost from 2024 to 2030/2035 by gas utility



Source: GWD modeling of utility revenue requirement

Findings: Average utility delivery cost per customer

Assuming constant rather than BaU levels of capital spending on gas infrastructure reduces average delivery costs per customer relative to BaU spending, even with moderate or heavy levels of customer decline (see Figure 5.7). The reduction is 10 to 13 percentage points by 2030, relative to BaU, depending on the gas utility. By 2035, the reduction is more significant, ranging from 35 to 60 percentage points depending on the gas utility. Looking across the four companies, flat capital spending lowers average gas delivery costs by roughly 25 percent by 2040.

Flat CapEx delays the doubling of rate burdens somewhat, but per customer revenue requirements still double by the mid-to-late 2030s, underscoring the difficulty of reducing the rate of increase in the rate burden because of the significant size of each company's rate base and its associated unrecovered cost.

Declining CapEx with customer departures

Scenarios 5 and 6 explore the effect of declining capital spending with moderate and high levels of customer departures.

Findings: Total CapEx

Reducing CapEx in line with customer departures decreases cumulative gas utility spending by 2050 by 67 percent for moderate levels of departures and 72 percent for high levels, relative to BaU spending levels. Total cumulative CapEx is reduced by between $66 and $71 billion for the moderate and high departure levels, respectively. Under declining CapEx, total annual spending across the four gas utilities is below $1 billion in 2050, compared to annual spending of $1.5 billion in 2050 for the flat CapEx scenario.

Findings: Total cumulative revenue requirement by 2050

Declining CapEx has an even more favorable impact on the long-term cost challenge of the gas system than flat spending. Compared to the Reference Case and assuming moderate customer departures, decreased spending lowers the cumulative 2050 revenue requirement by 36 percent, or $61 billion.

Table 5.3: Change in unrecovered gas plant from 2024 to 2050 for different capital spending levels and moderate customer departure ($ million)

		Ameren	Nicor	North Shore	Peoples	Total
2024 unrecovered gas plant		$2,842	$5,972	$424	$4,194	$13,431
BaU, moderate (2050)	Unrecovered plant	$16,728	$40,736	$2,520	$19,970	$79,954
	Change from 2024	589%	682%	595%	476%	595%
Flat, moderate (2050)	Unrecovered plant	$7,017	$17,424	$1,003	$7,570	$33,014
	Change from 2024	247%	292%	237%	181%	246%
Decline, moderate (2050)	Unrecovered plant	$5,577	$13,946	$780	$5,768	$26,071
	Change from 2024	196%	234%	184%	138%	194%

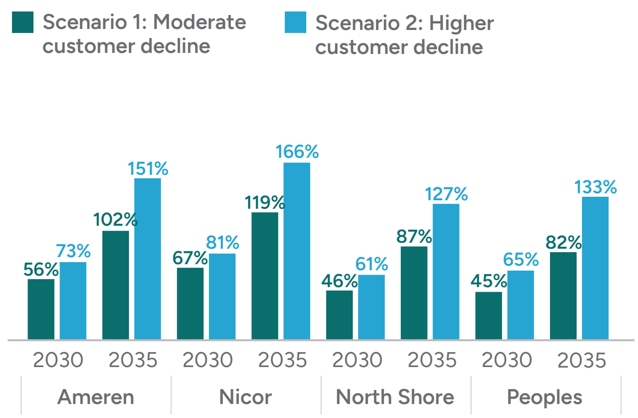
Source: GWD modeling of unrecovered plant based on modeled utility capital spending and customer departures

For high levels of customer departure, it falls by $71 billion or 42 percent.

Findings: Average utility delivery cost per customer

Both flat CapEx and declining CapEx significantly control the increase in average delivery costs per customer over the longer term compared to BaU. However, as in the other scenarios, rate burdens still double by the mid-to-late 2030s. The impact of declining CapEx versus BaU or flat spending is most significant when it comes to controlling the rise in rate burden by 2050, although similar to Scenario 4 (where CapEx is flat and customer departures are high), a high rate of customer departures (Scenario 6) greatly increases revenue requirement per customer by 2050. In other words, declining CapEx abates some of the adverse impact of customer departures on average delivery costs, but rate burdens are still 14 to 17 times higher in 2050 than in 2024.

Figure 5.8: Declining CapEx with customer departures—Percent increase in average delivery cost from 2024 to 2030 and 2035 by gas utility



Source: GWD modeling of utility revenue requirement

F. Unrecovered costs and stranded asset risk

Understanding and managing the risk of stranded gas assets is a paramount task confronting regulators at this critical juncture in the energy transition. This risk matters to utilities and their investors, but it also matters to gas customers and ultimately to taxpayers, since all parties may be on the hook for dealing with outstanding cost recovery.

The metric used by this study for quantifying asset stranding risk is the unrecovered book value of assets at different points in time. Our modeling explores the sensitivity of unrecovered costs to different levels of capital spending management.

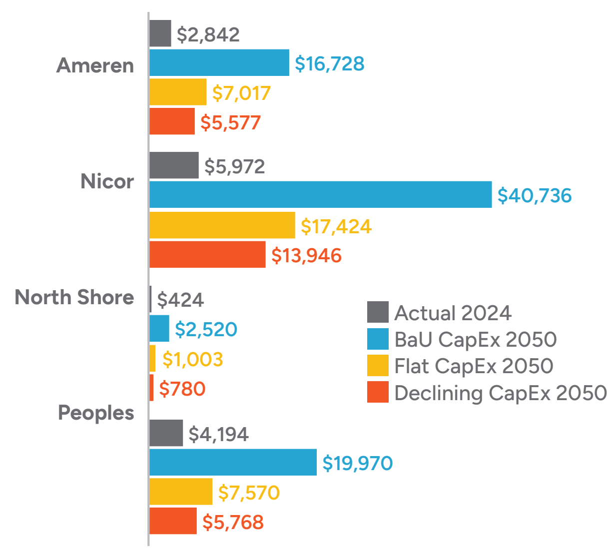
> **“Even under a declining CapEx scenario, unrecovered assets across the Big Four gas utilities are on track to nearly double by 2050, increasing from $13.4 billion today to $26.1 billion in 2050.”**

As of 2024, unrecovered gas plant for the Big Four gas utilities totaled $13.4 billion (see Table 5.3). Nicor had the highest unrecovered balance ($6 billion), followed by Peoples ($4.2 billion), Ameren ($2.8 billion), and North Shore ($424 million).

In Figure 5.9 and Table 5.3, we examine stranded asset risk as of 2050, Illinois' target year for clean energy. We find that:

1. **Continued capital spending on gas infrastructure balloons stranded asset risks.** If capital spending proceeds at BaU rates (blue bars in figure 5.9), by 2050, total unrecovered plant across the four gas utilities would soar to $80 billion, a staggering six-fold increase from its 2024 level.
2. **CapEx discipline (flat or declining) can substantially reduce stranded asset risk for the gas distribution system.** Compared to BaU spending, *constant* spending (orange bars in Figure 5.9) results in total unrecovered assets of $33 billion by 2050, a 59 percent reduction compared to the BaU scenario of $80 billion. *Declining* spending (red bars) leads to $26 billion in unrecovered assets, or a 67 percent reduction in BaU unrecovered levels. For individual gas utilities, Figure 5.9 shows how lower CapEx levels translate into substantially lower unrecovered book value. For example, for Peoples, flat CapEx reduces unrecovered book value by 62 percent, or about $12.5 billion by 2050, compared to the BaU scenario. Declining CapEx reduces unrecovered balances even further—by 71 percent or $14 billion. Similar reductions are observed for the other gas utilities.
3. **While controlling capital spending will have a positive effect on reducing stranded asset risk, even under a declining CapEx scenario, unrecovered assets across the Big Four gas utilities are on track to nearly double by 2050, increasing from $13.4 billion today to $26.1 billion in 2050.** This reflects the strong undertow effect of the substantial capital spending that has occurred over the past decade with its long depreciation periods and rates of return on equity of roughly 9.4 percent.
4. **Nicor is the gas utility with the largest amount of assets subject to stranded asset risk (Nicor's unrecovered balances account for roughly 50 percent of each scenarios' total).** Peoples and Ameren each account for about a fifth of unrecovered assets and North Shore for the remaining 3 percent.

Figure 5.9: Stranded asset risk in 2024 and 2050 by gas utility for different CapEx levels and assuming moderate customer departure (million $)

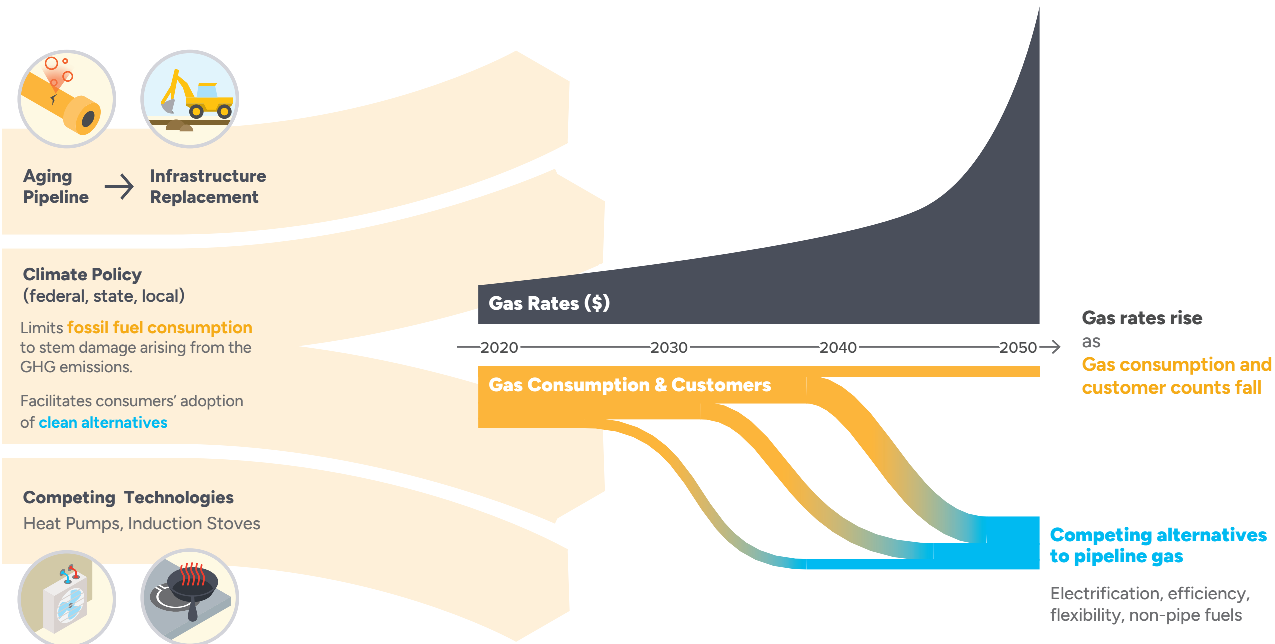


Source: GWD modeling of utility revenue requirement

The financial risk posed by stranded gas assets will be billions of dollars higher by 2050 than it is today unless gas utilities begin to wind down and substantially curtail their infrastructure investments. Regulators and policymakers must address the

> **Roughly a decade from now, continued business-as-usual spending accompanied by moderate customer departures will more than double average delivery costs within each gas utility territory.”**

Figure 5.10: Causes and effects of an unmanaged transition



Source: Michael E. Bloomberg and Michael J. Walsh, *The Future of Gas in New York State*, Building Decarbonization Coalition and Groundwork Data (March 2023), https://buildingdecarb.org/resource/the-future-of-gas-in-nys.

time-sensitive need to avoid or limit the creation of additional long-lived methane gas assets, since further infrastructure investments in the gas distribution system may well become uneconomic. Lower levels of spending today and over the near term will reduce the risk of unrecovered costs.

G. The devastating effects of an unmanaged transition

The cost forecasting presented in this section indicates an unsustainable future for Illinois' gas system if gas plant spending continues even at conservatively-estimated historic levels and if building electrification proceeds in a scattered and dispersed manner, driven solely by individual customer economics. To recap one of our central findings: Roughly a decade from now, continued business-as-usual spending accompanied by moderate customer departures will more than double average delivery costs within each gas utility territory, and, by 2040, rate burdens would be prohibitively high, regardless of capital spending strategy.

Figure 5.10 illustrates these dynamics, showing how emerging alternatives plus the high cost of gas encourage departures and create a negative feedback loop that further increases customer rates.

The hallmark of an unmanaged transition is continued spending on and investment in the gas system that fails to take advantage of opportunities to rein in costs and accelerate emissions reductions. Additional gas infrastructure spending and consumption further lock-in fossil fuels and slow the transition toward renewable energy systems. Gas bills go up and customers are increasingly enticed by electrification. Cost savings that could be achieved by substituting non-gas alternatives for pipeline replacement are foregone. In addition, missed opportunities to coordinate gas pipeline retirement with neighborhood-scale electrification create higher system-wide costs for everyone.

Without intervention for the public good, non-gas alternatives will come to dominate in more affluent areas. Other first adopters will likely be larger consumers, such as college campuses and hospitals[152] (gas utilities suffer noticeable revenue hits with these departures). The overbuilt, underutilized, high-cost gas system will come to serve a dwindling base of energy-burdened customers living in more urbanized areas and environmental justice communities. Those with the least ability to leave the system will become increasingly burdened. While low-income gas ratepayers in Illinois will soon secure some degree of affordability protection via the new low-income discount rate, the solvency of this new rate structure could be challenged if the cost of the shifted rate burden becomes unattractive for non-low-income households, adding to the incentive to leave the gas system due to its increasing costs.

Another formidable feature of an unmanaged transition is growing uncertainty regarding the fate of the gas industry's massive unrecovered gas assets: we estimate these could total as much as $80 billion by 2050. In play could be decades of legal claims, the resolution of which may burden ratepayers and taxpayers for generations to come.

Compared to the managed gas transition that we consider in Section 6, an unmanaged transition would be more costly, more inequitable, and will delay progress on climate goals. Continued reliance on pipeline gas will also adversely impact public health (see Section 2) and may lead to greater safety and reliability risks if utilities cut back on workforce levels and needed safety investments in response to pressure on utility finances due to declining revenues.

The question confronting Illinois regulators and policymakers is not unmanaged versus managed but rather what kind of managed transition should be put in place to guide and shape Illinois' future beyond gas, as an unmanaged transition is not a viable option. Given the urgency of reducing greenhouse gas emissions, clear signals are needed to establish a robust timeline for implementing an orderly gas transition. In the following section, we introduce a basic framework for understanding the essential elements of a managed gas transition and approaches to addressing key policy and regulatory barriers that are likely to impede forward progress.

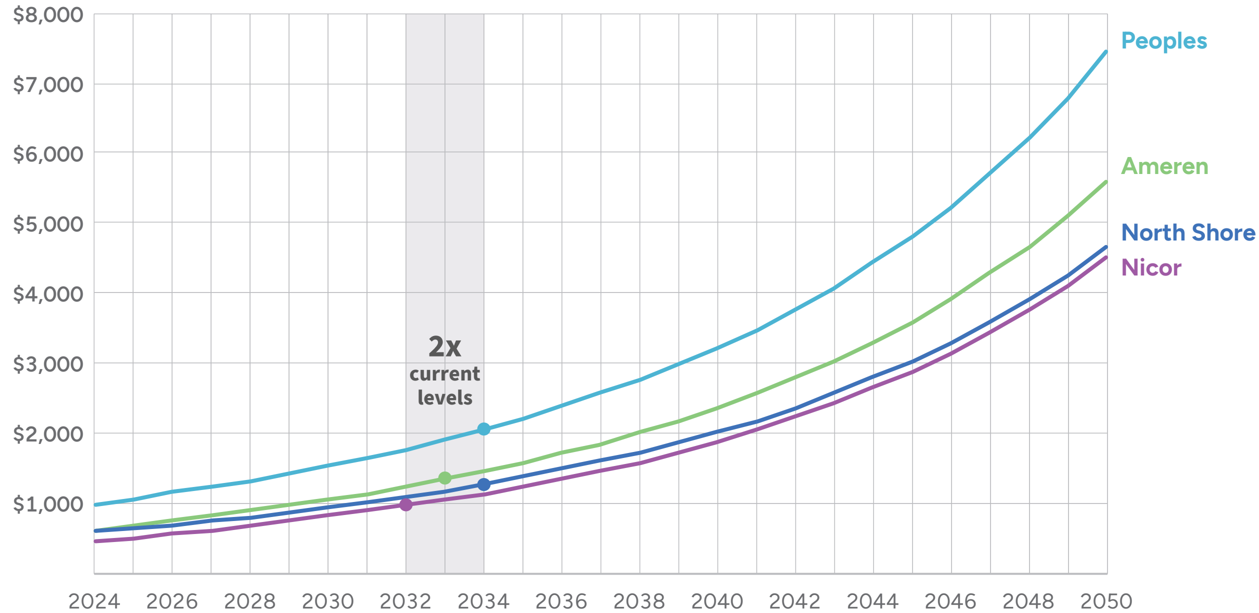
H. Detailed scenario modeling results

As indicated in Table 5.2 ("Modeling Scenario Descriptions"), the modeling exercise conducted for this report analyzes six different scenarios for each of the Big Four gas utilities. Each scenario reflects a distinct set of assumptions about capital spending and customer departures from the gas system. The following six figures summarize the scenario results concerning revenue requirement per customer over the time period 2024-2050.

152 Stan Cross, David J. Eagan, Paul Tolmé, Julian Keniry, and John Kelly, *Going Underground on Campus: Tapping the Earth for Clean, Efficient Heating and Cooling*, National Wildlife Federation (2011), https://www.nwf.org/~/media/PDFs/Campus-Ecology/Reports/Geothermal%20Guide%20FINAL%203-1-11.ashx

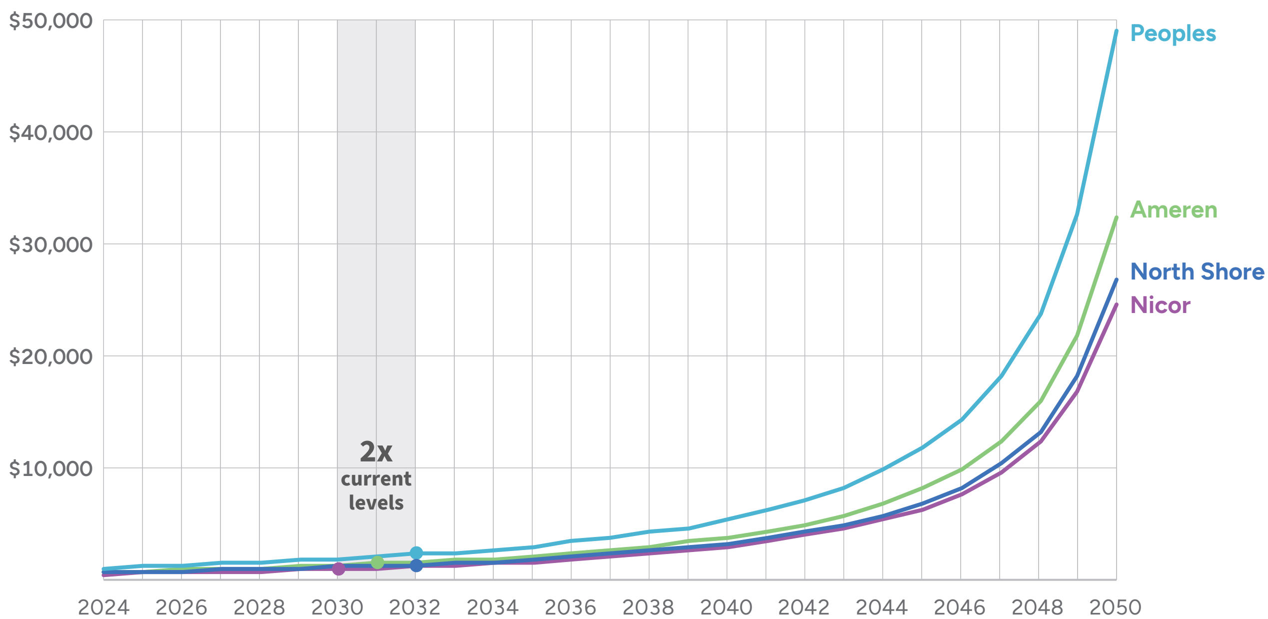
Scenario 1: Business-as-usual CapEx with moderate customer decline

Figure 5.11: Annual revenue requirement per customer with BaU CapEx and moderate customer departure



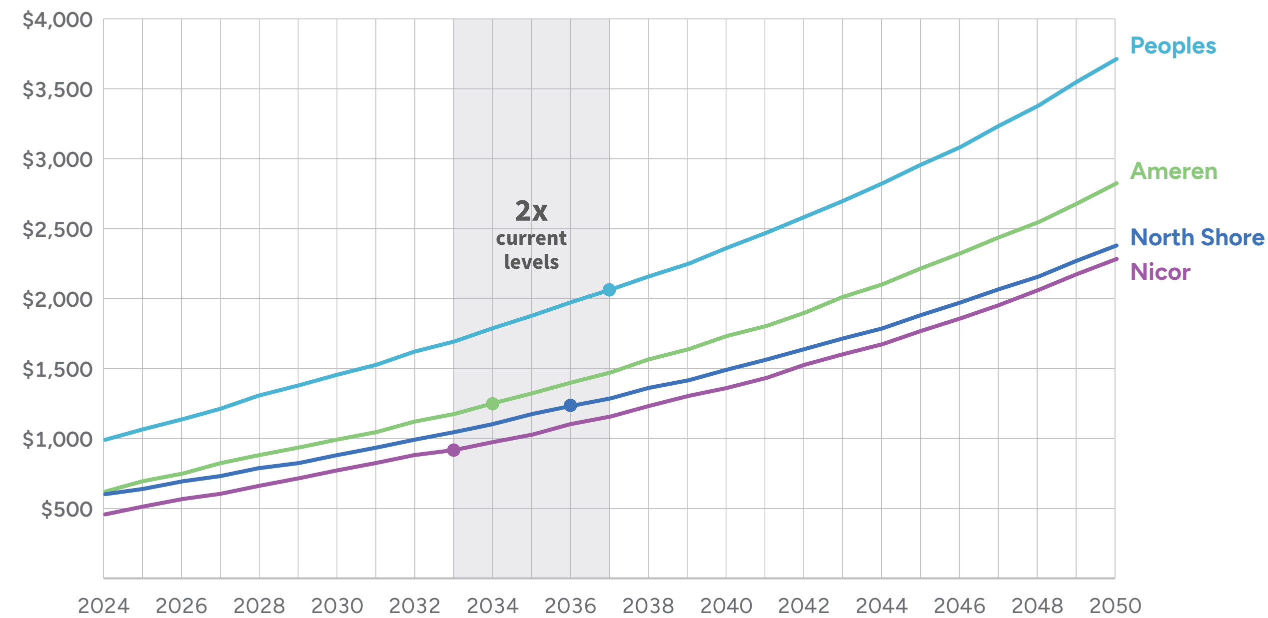
Scenario 2: Business-as-usual CapEx with high customer decline

Figure 5.12: Annual revenue requirement per customer with BaU CapEx and high customer departure



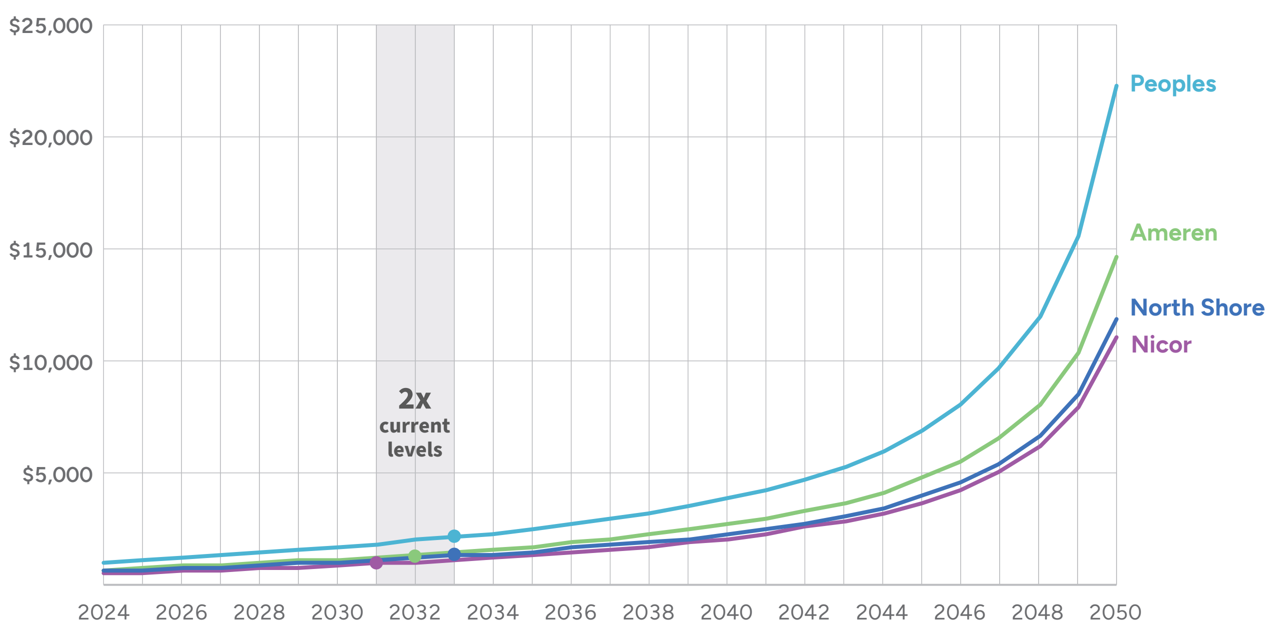
Scenario 3: Flat CapEx with moderate customer decline

Figure 5.13: Annual revenue requirement per customer with flat CapEx and moderate customer departure



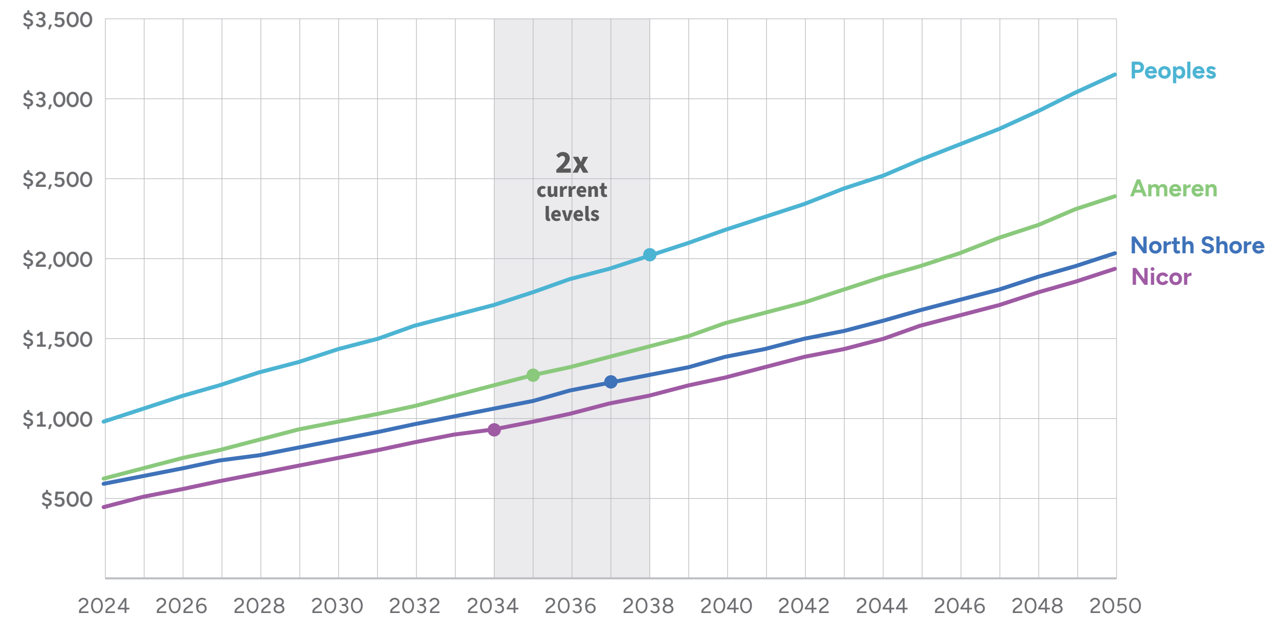
Scenario 4: Flat CapEx with high customer decline

Figure 5.14: Annual revenue requirement per customer with flat CapEx and high customer departure



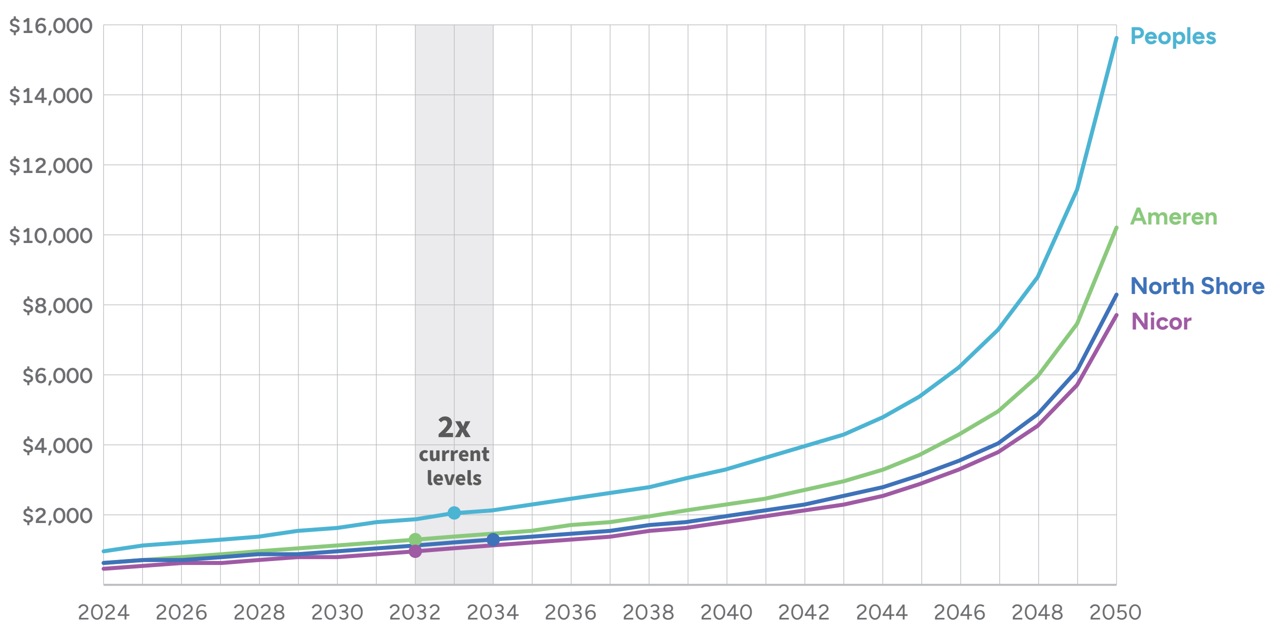
Scenario 5: Declining CapEx with moderate customer decline

Figure 5.15: Annual revenue requirement per customer with declining CapEx and moderate customer departure



Scenario 6: Declining CapEx with high customer decline

Figure 5.16: Annual revenue requirement per customer with declining CapEx and high customer departure



Section 6

Toward a Managed Transition off the Gas Distribution System

A. Key takeaways

- The shift toward a clean energy economy is underway in Illinois. However, there are several decision points ahead that will determine whether the gas transition off methane gas unfolds in an unmanaged and inequitable manner or if it evolves as a thoughtful, managed, and just transition.
- A managed gas transition is a comprehensive strategy involving regulatory oversight and stakeholder collaboration to phase out pipeline delivered methane gas for clean energy while ensuring safety, reliability, and affordability. A managed gas transition in Illinois has three fundamental building blocks: halting system expansion, avoiding reinvestment, and strategic downsizing of the gas system.
- A managed transition enables the redirection of gas investments to non-fossil fuel alternatives, thereby reducing gas capital spending and stranded asset risk while creating financing opportunities to ensure clean alternatives are more equitably available.
- Gas system decommissioning projects require the development of rigorous frameworks for identifying and evaluating non-pipeline replacement alternatives such as advanced leak repair, pipeline decommissioning, thermal energy networks, and electrification.
- Attention should be directed to crucial upstream policy and regulatory barriers that, if not addressed, are likely to impede or weaken a successful managed transition away from fossil gas.
- Recognizing that the energy transition is proceeding at a rapid pace and that the gas system must change in response, the ICC has begun laying a formal path for a managed gas transition by initiating a statewide "future of gas" proceeding, creating a requirement that utilities file Long-Term Gas Infrastructure Plans, and, with its 2023 rate case orders, instituting increased scrutiny of future gas plant spending requests.

B. Introduction

Illinois has long been at the forefront of public utility regulation, notably demonstrated when the U.S. Supreme Court upheld the state's authority to regulate utilities in the landmark case of Munn v. Illinois, an 1873 decision that laid the groundwork for utility commission authority across the country.[153] Over its 103-year history, the ICC has adapted to evolving challenges and opportunities within the landscape of energy regulation. Significant events, such as the energy crisis of the 1970s and the regulatory restructuring wave of the 1990s, have shaped the ICC's objectives, roles, and authorities.

153 Munn v. Illinois, 94 U.S. 113 (1876).

Since the end of World War II, the ICC has facilitated the orderly expansion of the gas distribution system. More recently, it has shifted gears to usher in protracted gas infrastructure replacement due to the aging of the original infrastructure. This wave of pipeline replacement is creating a new generation of expensive, long-lived, fixed assets that are non-fungible. But now, regulatory commissions around the country, including the ICC, must address new transformational goals relating to GHG emissions and the decarbonization of the economy. Market structures are shifting, the economics of gas is fundamentally challenged, technological competition is unprecedented, and the social costs of gas and equity and environmental justice concerns have become paramount. The Commission's 2023 rate case orders for the state's Big Four gas utilities signal a shift to a more proactive approach to managing the state's aging gas system within the context of this economy-wide energy paradigm shift. This pivot also conveys a crucial signal to utility investors about the shifting economic landscape of the gas system and the future of gas as a whole.

In this section, we examine the challenges and requirements of an expanded ICC regulatory mandate that seeks to balance multiple priorities, including longstanding priorities of safety and reliability but now also reductions in GHG emissions, equity, public health, and affordability. We introduce the concept of a managed, phased gas transition aligned with state climate law and goals. This proactive approach aims to achieve climate targets while minimizing adverse impacts on the public, addressing concerns that are already arising in the absence of managed transition efforts. We incorporate findings and examples from gas proceedings across the country that are addressing challenges similar to those in Illinois and we distill these into three "building blocks" of a managed gas transition. Finally, for Illinois policymakers, we identify the key obstacles or challenges likely to impede or weaken a managed gas transition. Some are regulatory; others are necessary for an effective whole-of-government approach to supporting the transition.

C. What is a managed gas transition?

A managed gas transition is a comprehensive strategy involving regulatory oversight and stakeholder collaboration to phase out pipeline-delivered methane gas for clean energy while ensuring safety, reliability, and affordability. This approach is marked by coordinated investments and actions from utilities, consumers, and policymakers. It includes the deployment of non-GHG-emitting technologies, policy reforms, and safeguards for affected communities and workers, aligning with decarbonization goals for a sustainable energy shift without undue hardship or service interruptions.

A managed transition in Illinois will necessarily take place over time, and planning will be required to sustain parts of the gas system for perhaps several decades alongside emerging zero-carbon installations. One emerging strategy for synchronizing this transition off the gas system involves an organizing entity, such as a utility, coordinating a neighborhood-scale transition of buildings to decarbonized energy sources and electric equipment.[154] While the strategy for intervention will evolve alongside technological innovation, customer demand, and other factors, this section highlights three building blocks of the managed transition off the gas system that can be instituted today: halting system expansion, avoiding reinvestment, and strategically downsizing.

Halt gas system expansion

In the near term, a managed gas transition must begin by taking steps to avoid large, multi-decade gas system capital expenditures, whether by gas utilities or gas customers. The most effective way to do this is to not allow new hook-ups to the gas system because these lock in new long-lived assets and increase the costs of decarbonization. In addition, growing the gas system during the clean energy transition means taking on the additional

154 Kristin George Bagdanov, Claire Halbrook, and Amy Rider, *Neighborhood Scale: The Future of Building Decarbonization*, Building Decarbonization Coalition and Gridworks (December 2023), https://buildingdecarb.org/resource/neighborhoodscale.

risk that the new lines may be subject to early retirement or underutilization as customers leave the gas system. New gas system growth also increases the inequitable distribution of system costs, as those left on the system must cover the remaining cost of the line extension.

Below are examples of state actions currently underway to curtail gas system expansion.

- **Limiting or removing gas line extension allowances.** As of 2023, five states (California, Colorado, Connecticut, Oregon, and Washington) have taken steps to reduce or even dismantle gas line extension allowances. States are determining that these allowances are no longer cost-effective or compatible with state climate goals.
- **All-electric building codes.** A growing number of cities are revising their building codes to require newly constructed buildings to be all electric (Berkeley, Los Angeles, and San Francisco in California; Seattle and New York City elsewhere). At the state level, New York recently enacted the nation's first legislative ban on fossil fuel appliances in most new buildings. Massachusetts is piloting a municipal program to restrict fossil fuel use in new construction.[155] Some of these city and state efforts have been challenged by lawsuits (e.g., Berkeley and New York). The City of Chicago recently introduced an ordinance to limit fossil fuel combustion in new construction or for buildings undergoing major renovations.[156] At the state level, CEJA mandated that Illinois develop a Stretch Energy Code to achieve greater building energy efficiency. The draft code incentivizes, but does not mandate, electric over gas in new construction.[157]

155 Chris Lisinski, "Pilot Allowing Bans on New Gas Hookups Is Limited to 10 Mass. Communities. There's 1 Spot Left." WBUR (September 14, 2023), https://www.wbur.org/news/2023/09/14/gas-hookup-electric-pilot-massachusetts.

156 Chicago, Illinois, Amendment of Municipal Code Chapters 14N and 18 (pending), https://chicityclerkelms.chicago.gov/Matter/?matterId=ADFABB50-29BA-EE11-A568-001DD8069864.

157 CEJA required the establishment of a Stretch Energy Code that would be available for municipalities to adopt (or opt into) beginning in June 2024. The code will be based on the International Energy Conservation Code (IECC) with some modifications. Despite some calls for the stretch code to require all electric buildings, the draft code still allows for the use of fossil fuels. However, buildings that use fossil fuels will be required to implement additional energy efficiency measures, such as high efficiency furnaces, lower air exchange rates, and greater efficiency applications. The stretch code also requires new construction buildings to be electric-ready. https://cdb.illinois.gov/business/codes/illinois-energy-codes/illinois-stretch-energy-code.html.

Limit reinvestment in the gas distribution system

A systematic plan for restricting and reducing capital spending on the replacement of existing gas infrastructure is a critical component of a managed gas transition. As our modeling shows, such spending reductions can play a crucial role in reducing further gas asset lock-ins and managing near- and long-term costs as customers exit the system.

Below are examples of actions to avoid reinvestment in the gas system:

- **Sunset accelerated cost recovery programs and re-evaluate accelerated replacement programs.** Across the U.S., over forty states have allowed rate surcharges and riders to be added to gas ratepayer bills in order to allow gas utilities to recoup their spending on replacing legacy pipes more quickly outside of their rate cases.[158] Illinois is a stand-out example of a state that has terminated its accelerated cost recovery program (QIP), a phaseout provided for by the original statute.[159] It should be noted that sunsetting an accelerated cost recovery does not terminate pipeline replacement, as replacement can still occur under usual cost-of-service rate recovery. As a result, programs that allow for accelerated replacement of gas infrastructure should be re-evaluated, even if expedited cost recovery has been eliminated. Illinois here too is a case in point: under its System Modernization Program (SMP), Peoples is due to replace about 1,000 miles of gas distribution pipeline through 2040 at the cost of over $250 million per year. In its final 2023 rate case order, the ICC directed that the SMP be paused while an investigation is conducted "to determine the reasonableness and prudence of the Company's next iteration of the SMP."[160]
- **Require regulatory consideration of non-gas pipeline alternatives (NPAs).** NPAs are investments or targeted actions that delay, reduce, or avoid the need to build up or

158 NARUC, *Natural Gas Distribution Infrastructure Replacement and Modernization: A Review of State Programs* (January 2020).

159 IL Administrative Code, Title 83, Part 556.40.

160 ICC, Final Order, 2023 Rate Case for Peoples, Docket 23-0068, p. 30, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306/files/601245.pdf.

upgrade traditional gas infrastructure such as pipelines, storage, and peaking resources. Public utility commissions in California, Colorado, Massachusetts, New York, Oregon, and Rhode Island now in some form require gas utilities to evaluate and consider NPAs as a substitute for pipeline replacement, often using an expanded benefit/cost framework that incorporates life-cycle emissions analysis.[161] NPA frameworks have been proposed in regulatory dockets in other states or jurisdictions, including Illinois and Philadelphia.

- **Regulatory disallowance of requested utility capital spending and rate hikes.** Breaking with the relatively permissive approach of regulatory commissions to utility requests for rate hikes and capital expenditures, recent regulatory commission rulings in Colorado, Illinois, Michigan, and Minnesota show increased scrutiny. Illinois is the most significant and recent example. In its 2023 rate case orders for the state's Big Four gas utilities, the ICC disallowed portions of gas utility spending requests for each company and reduced proposed rate hikes, sending a strong message of tightened regulatory oversight.[162] The ICC found that the gas utilities did not provide sufficient justification for the full amounts requested.
- **Advanced leak detection and repair.** Advancements in pipe repair can now help avoid intensive pipe replacement for certain types of pipe and pressure settings, often with significant cost savings compared to pipeline replacement. This allows pipeline replacement to be reserved for instances where leak repair is not feasible or unlikely to be effective. New technologies—many of them trenchless—can help control methane leaks and can significantly extend the life of a leaking or leak-prone pipe. Examples of state policies promoting advanced leak repair are few and far between (Massachusetts is one example).[163]

161 Ron Nelson et al., *Non-Pipeline Alternatives to Natural Gas Utility Infrastructure: An Examination of Existing Regulatory Approaches*, prepared for the Lawrence Berkeley National Laboratory by Strategen (November 2023), https://eta-publications.lbl.gov/sites/default/files/non-pipeline_alternatives_to_natural_gas_utility_infrastructure_1_final.pdf.

162 Total rate hikes for the four companies were cut by $300 million and rate base increases tied to capital spending were reigned in by $677 million, or about 40%. In the case of Peoples Gas, the ICC paused the company's infrastructure replacement program ($265 million in capital spending) and ordered a new investigation of the company's infrastructure replacement program. Illinois Commerce Commission, Rate Cases Orders in Dockets 23-0066, 23-0067, 23-0068, 23-0069 (November 16, 2023).

Strategically downsize the gas distribution system

A managed gas transition goes beyond curtailing expansion and reinvestment in the gas distribution system to creating a detailed, phased plan for downsizing and decommissioning the gas system over time. This approach requires coordinated, locally-focused gas and electric building resource planning to identify, optimize, and prioritize transition strategies tailored to local infrastructure conditions and socioeconomic variables. Considerations can include the state of the building stock (age, envelope efficiency status, structural deficiencies), the prevalence of distributed energy resources (rooftop solar, batteries), potential thermal energy resources including opportunities for geothermal energy, and local demographic features (household energy burdens, environmental and health burdens).

Downsizing occurs at the scale of multiple streets or neighborhoods and requires coordinating the decommissioning of the gas network with the sequenced deployment of alternative solutions for energy needs. Such neighborhood-scale transitions must also include a framework for robust customer engagement and unified platforms that streamline household access to resources, incentives, and flexible funding.

Neighborhood-scale decarbonization projects and planning

To-date, the most advanced efforts to pare back the gas system have been focused on targeted electrification of buildings using air-source heat pumps. In addition to this strategy, a number of pilots are underway to test thermal energy networks as a means for transitioning whole neighborhoods off of gas. Below are examples of technologies and

163 In Massachusetts, the Act Driving Clean Energy and Offshore Wind of 2022 broadens the state's accelerated cost recovery for replacing vintage gas system infrastructure to include advanced leak repair that extends the life of the pipe for at least ten years.

regulatory frameworks that can facilitate gas asset retirement and enable gas system downsizing.[164]

- **Targeted and zonal electrification:** Several states are advancing or encouraging targeted or zonal electrification projects and pilots that provide for retiring gas pipeline segments. The California Energy Commission's Tactical Gas Decommissioning Project is seeking to identify three pilot sites for gas decommissioning.[165] In the District of Columbia, the Department of Energy & Environment recently released a detailed roadmap for strategically electrifying buildings and transportation in the District, based on the understanding that phasing fossil fuels out of the District's energy supply is essential to achieving the city's climate commitments.[166] In Massachusetts, in December 2023 the DPU ordered that each gas utility coordinate with the relevant electric company to propose at least one demonstration project for "decommissioning an area of its system through targeted electrification."[167] In Minnesota, the Natural Gas Innovation Act of 2021-2022 permits gas companies to sell electric heating technologies such as ASHPs and geothermal or aquifer thermal applications. It also encourages gas utilities to undertake pilots that decarbonize their operations, including biogas, RNG, hydrogen, ammonia, carbon capture, strategic electrification, district energy, and energy efficiency.[168]

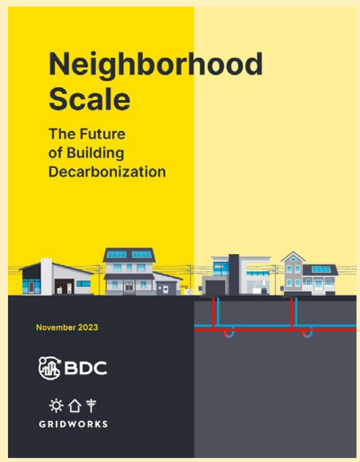
- **Thermal energy networks (TENs).** Several utility-sponsored thermal energy network projects are under development across the country. In Massachusetts, Eversource and National Grid are leading a total of three projects. In New York, plans for 13 utility TEN projects have been proposed as required under the Utility Thermal Energy Network and Jobs Act. To encourage TEN pilots, Colorado and Minnesota have each taken steps to expand their definitions of clean heat resources to include thermal energy and/or to provide that gas utilities can sell thermal energy. At the local level in Illinois, the environmental justice organization, Blacks In Green, is piloting non-utility ownership models for thermal energy networks in Chicago. In 2023, the organization received funding from the Department of Energy "to design and develop a community geothermal heating and cooling district…across four city blocks containing more than 100 multi-family

Report

Neighborhood-scale building decarbonization

Neighborhood-scale building decarbonization focuses on transitioning street segments, developments, or even entire neighborhoods to decarbonized energy sources and electric appliances with the end goal of managing the transition off of the gas system.

See BDC's 2023 report.



164 For a comprehensive analysis of methods for downsizing the gas system, see BDC's 2023 report on neighborhood-scale building decarbonization: Kristin George Bagdanov, Claire Halbrook, and Amy Rider, *Neighborhood Scale: The Future of Building Decarbonization*, Building Decarbonization Coalition and Gridworks (December 2023), https://buildingdecarb.org/resource/neighborhoodscale.

165 Gridworks, "Site Prioritization: Identifying Three Proposed Gas Decommissioning Pilot Locations" (August 17, 2023), https://gridworks.org/2023/08/site-prioritization-identifying-three-proposed-gas-decommissioning-pilot-locations/

166 DOEE, The Strategic Electrification Roadmap for Buildings and Transportation in the District of Columbia (April 2023). https://doee.dc.gov/sites/default/files/dc/sites/ddoe/page_content/attachments/Strategic%20Electrification%20Roadmap-reducedsize.pdf

167 MA DPU, Order on Regulatory Principles and Framework, DPU 20-80-B (December 6, 2023), p. 87. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602

168 Frank Jossi, "Under new law, Minnesota gas utilities could play a role in electrification," *Energy News Network* (July 21, 2021). https://energynews.us/2021/07/21/under-new-law-minnesota-gas-utilities-could-play-a-role-in-electrification/

and single-family homes."[169] At the state level, the ICC held a workshop on thermal energy networks in 2023 and submitted a report with recommendations on the role of TENs in Illinois's clean energy future to the Governor and General Assembly. The workshop covered a variety of issues, including: different ownership models for TENs; synergies with existing weatherization and energy efficiency programs; contributions to climate justice and equitable building electrification; and the role of TENs in creating a just transition for utility workers. The final report recommended exploring utility and non-utility ownership models, necessary regulatory and legislative changes, consumer protections, and other recommendations.[170]

Frameworks for identifying and evaluating decommissioning candidates

Moving beyond the pilot phase for neighborhood-scale decarbonization requires developing rigorous frameworks for identifying and evaluating pipe replacement alternative projects. California is currently leading efforts to develop novel, analytical tools for targeted decommissioning of pipeline gas infrastructure.

- **Tactical Gas Decommissioning:** The California Energy Commission's Tactical Gas Decommissioning Project is developing a "data-driven actionable tool" to identify segments of a given gas distribution system that, if decommissioned, would result in gas system cost savings.[171] The project is developing benefit-cost analytics and data requirements for identifying and evaluating candidate pilot sites for future gas decommissioning and targeted electrification. A recent study for the project evaluates 11 candidate sites in the San Francisco Bay Area and finds that, for each site, "considerable cost savings could be achieved even after paying for building electrification."[172] The avoided cost of gas main and service replacement play a substantial role in the costing framework.
- **Gas Asset Analysis Tool:** Pacific Gas and Electric (PG&E) in California has developed an internal Gas Asset Analysis Tool to identify locations where zonal electrification and/or targeted decommissioning of the methane gas system may reduce gas system costs: "The tool aims to synthesize various system conditions and asset characteristics—such as, but not limited to, age of assets, risks, number of customers, and system throughput—to provide insight about locations that may warrant further engineering and/or costing review for zonal electrification."[173] As part of its 2023 rate case, PG&E also has voluntarily developed a small-scale electrification program (Integrated Investment Program). One related project includes downrating a pipe from transmission to distribution pressure and decommissioning radial lines.
- **Integrated Planning Tools:** Federal and state funding has also begun supporting the development of technical frameworks and tools that encourage longer planning horizons and integrated planning between gas and electric systems. These expanded planning frameworks can be particularly useful for identifying where alternative strategies are viable for sections of the gas network that are already slated for pipeline replacement. An example of this is the Local Energy Asset Planning (LEAP) tool developed by Groundwork Data with support from the U.S. Department of Energy and the Massachusetts Department of Energy Resources.[174]

169 Juanpablo Ramirez-Franco, "A Geothermal Energy Boom Could Be Coming to Chicago's South Side," *Grist* (February 23, 2024), https://grist.org/cities/black-communities-south-side-chicago-geothermal-heat/.
170 ICC, "Illinois Commerce Commission Thermal Energy Network Report," February 2024. https://icc.illinois.gov/api/web-management/documents/downloads/public/TEN/Thermal%20Energy%20Network%20Report%202024.pdf
171 California Energy Commission, Staff Workshop on Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Natural Gas Infrastructure and GFO-21-504 - Development of a Data-Driven Tool to Support Strategic and Equitable Decommissioning of Gas Infrastructure.
172 Aryeh Gold-Parker et al., *Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California: Evaluation of 11 Candidate Sites in the San Francisco Bay Area*, California Energy Commission (December 2023), p. 9. https://www.ethree.com/wp-content/uploads/2023/12/E3_Benefit-Cost-Analysis-of-Targeted-Electrification-and-Gas-Decommissioning-in-California.pdf
173 PG&E Comments on the Draft 2021 Integrated Energy Policy Report (IEPR), Volume III Decarbonizing the State's Gas System, Docket 21-IEPR-01 (January 28, 2022), https://efiling.energy.ca.gov/GetDocument.aspx?tn=241334.
174 UMass Amherst Energy Transition Institute, *Equitable Energy Transition Planning in Holyoke Massachusetts: A Technical Analysis for Strategic Gas Decommissioning and Grid Resiliency* (December 2023, prepared by Groundwork Data), https://doi.org/10.7275/enzr-5311

Cost savings from avoided gas pipeline replacement

A further consideration is the magnitude of the savings created by avoided gas system investments. A recent study in California of PG&E territory found that the average avoided direct cost of pipe replacement across 11 candidate decommissioning sites was equivalent to $25,000 per household.[175] Using this methodology of avoided replacement cost per customer, Table 6.1 shows rough estimates of similar avoided cost estimates for Ameren, Nicor, and Peoples using their systemwide average QIP costs in 2023 (see Table 3.1). (It should be noted that, for Ameren and Nicor, it is unclear if the reported cost data includes the cost of retiring the existing pipe and if the costs are fully loaded with all indirect costs.)

Table 6.1: Estimated potential avoided gas main replacement costs per customer (direct capital costs only), 2023

	Gas avoided costs per customer ($)
Ameren	$13,779
Nicor	$28,145
Peoples	$10,025 (or $16,503 including installation & retirement cost, service replacement, and meter moves)

Source: For spend per mile, see sources for Table 3.1 in Section 3.D "Spending to install a mile of distribution main by gas utility, 2023." For customer per mile of main, see ICC, Comparison of Gas Sales Statistics for 2022 and PHMSA, Form 7100.1 for 2022. Cost figures for Peoples are calculated as a weighted average of 2023 miles replaced under Neighborhood vs. Public/System Improvement portions of SMP, as reported in the Q4 2023 SMP Report.

Transitional fuel strategies

While a neighborhood-scale transition is intended to address whole segments of the gas system at once, intermediate steps can be taken to decarbonize existing buildings in harder-to-decarbonize areas or prior to a neighborhood-scale transition. Two strategies for gradually transitioning buildings from gas to electric equipment are "AC to heat pump" and non-pipeline fuels.

- An **AC-to-heat-pump** strategy targets homes that are adding or replacing a cooling load by swapping out a traditional central AC unit with a heat pump. This switch allows the existing gas furnace to provide back-up heat until the home is ready to fully transition to the heat pump for both heating and cooling. A 2023 BDC report examines how the installation of heat pumps instead of central AC units can improve health and climate outcomes. It finds that heat pumps are poised to take over this portion of the HVAC market, but need supportive policies and education to do so.[176] In Illinois, incentives, education, and policies promoting the installation of heat pumps instead of air conditioners could unlock massive potential for market growth, especially as more than one-third of households in the Midwest report HVAC equipment that is 15 years or older.[177] According to HARDI data from 2013 to 2021, air conditioners accounted for 59 percent of all HVAC sales in Illinois, with air-source heat pumps (ASHPs) accounting for 8 percent of all HVAC sales.[178] Replacing a traditional electric air conditioner with an electric heat pump or installing a heat pump in a home that is adding cooling for the first time has the potential to increase heat pump adoption seven-fold.
- Although not a long-term solution for reducing GHG emissions or improving indoor air quality, non-pipeline **hybrid fuel** solutions that combine an ASHP with a propane burner for space or water heating may be necessary in some circumstances to uphold a customer's choice while offering an immediate cost-effective alternative to multi-million dollar gas pipeline replacement projects. In addition, some consumers may be interested in electrification measures for their homes and neighborhoods if they are able to maintain combustible cooking methods. For example, a recent study found that 31 percent of Americans want to electrify their home, but the share jumps

175 E3, *Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California* (June, 2023), Table 4, p. 11, https://gridworks.org/wp-content/uploads/2023/06/Evaluation-Framework-for-Strategic-Gas-Decommissioning-in-Northern-California-Interim-Report-for-CEC-PIR-20-009.pdf

176 Building Decarbonization Coalition. *Why Cooling Is Key: How to Decarbonize Buildings with One Weird Trick*, (June 2023). https://buildingdecarb.org/wp-content/uploads/Heat-Pump-Shipment-Report-Spring-2023_V4.pdf.

177 Katherine Shok, "Electrifying the Midwest" (October 17, 2023), https://atlasbuildingshub.com/2023/10/17/electrifying-the-midwest.

178 BDC analyzed HARDI (Heating, Air-conditioning & Refrigeration Distributors International) data, which includes the number of shipments for central AC systems, furnaces, and heat pumps from 2013 through 2021, as well as their efficiency and other characteristics.

to 60 percent when they are able to keep their gas stove.[179] Gas stoves can be converted to propane in a hybrid heating system, thereby eliminating the need for a connection to the gas pipeline distribution system. A growing body of research on the health risks of gas stoves may persuade more people to fully electrify, but propane may offer a near-term pathway for transitioning off the pipeline gas system in areas where consumers are hesitant to fully electrify.

Ideally whole homes and whole neighborhoods are transitioned off of all fossil fuels at once. These transitional strategies recognize that certain situations may call for more gradual, phased approaches to decarbonization.

D. Gas transition challenges and critical areas for policy and leadership

As Illinois moves forward to determine the shape of its managed gas transition framework, there are several "upstream" challenges or barriers that may be encountered. Without policy solutions, these barriers could impede or slow down the transition. We consider several of these challenges below.

Lack of mandated decarbonization targets for the building sector and gas industry

Nearly half of states have enacted overarching net-zero emission goals or clean energy targets for the period through 2050.[180] Only a small number, however, have specified sub-targets for the building sector and/or GHG emission sub-limits that specifically pertain to the gas distribution industry. In Illinois, an economy-wide 2050 clean energy goal has been established along with sector-specific decarbonization targets for retail sales of electricity and the transportation sector (1 million electric vehicles by 2030). No statewide decarbonization targets exist for the building sector or the gas industry.

The purpose of clean energy targets is to create directional incentives for action. Establishing sub-sector targets for the building sector or emission sub-limits for the gas industry serves to deliver clear signals to cities, localities, and the gas and electric utilities. Targets are most useful when they specify interim milestones (e.g., a 2050 goal with levels to be achieved by 2030, 2035, etc.). With regard to emissions goals for the gas distribution industry, some states have strengthened their programs by linking non-compliance to administrative penalties or to restricted rate recovery.

One challenge of decarbonization targets is that they are necessarily tied to the official measurement methodologies underlying federal and state GHG inventories. A substantial body of research shows that these methodologies tend to significantly underestimate actual methane and carbon dioxide emissions related to the gas industry supply chain.[181]

Lack of clarity as to the scope of authority of the ICC in aligning the gas system with a clean energy transition.

Gas utilities interact with public policy largely within the sphere of regulatory dockets and proceedings that are managed and overseen by public utility commissions. Legislatures and the executive branch, in turn, determine the purview and authority of the commissions. In the absence of directives that extend commission oversight responsibilities to include climate- and energy transition-related

179 Jennifer Marlon et al., "How Many Americans Want an Electric Home?," Yale Program on Climate Change Communication (blog) (November 16, 2023), https://climatecommunication.yale.edu/publications/electrification.

180 Clean Energy States Alliance, "Maps and Timelines of 100% Clean Energy States. Accessed March 18, 2024. https://www.cesa.org/projects/100-clean-energy-collaborative/guide/map-and-timelines-of-100-clean-energy-states/

181 Based on its review of recent peer-reviewed research using extensive field survey campaigns of pipeline infrastructure across the U.S., the Environmental Defense Fund (EDF) estimates that U.S. onshore gas pipeline methane leakage is between 3.75 times and 8 times greater than estimated by EPA. Renee McVay, *Methane Emissions from U.S. Gas Pipeline Leaks* (August 2023, Environmental Defense Fund), p. 6, https://www.edf.org/sites/default/files/documents/Pipeline%20Methane%20Leaks%20Report.pdf.

areas, gas utilities can and do argue that "climate issues" per se cannot be considered in regulatory proceedings such as rate cases, capital planning, procurement, and supply and demand forecasting. Instead, gas utilities argue that the purview of commissions must be confined to traditional safety and reliability concerns.

To be successful, a managed gas transition requires that the scope of authority of regulatory commissions be extended to include reductions in GHG emissions, equity, affordability, security, non-gas pipeline alternatives, stranded assets, and coordinated planning between gas and electric utilities. Without such broadened scope, commissions may be limited in their ability to align their oversight responsibilities with mandated state emissions goals, and may be unable to make necessary changes to gas planning processes, rate making, and utility programs regarding energy efficiency and electrification. Another approach is to provide commissions with the policymaking power to manage the transition, including purview over the impact of building decarbonization on gas and electric rates.[182]

In Illinois, the General Assembly has provided an expanded scope of authority to the ICC with respect to electric utilities but not yet to gas utilities. Expanded ICC authority for electric utilities now includes equity, affordability, and reductions in GHGs to meet statewide greenhouse gas emissions limits.[183]

Lack of modernized gas planning regulatory frameworks

While expanded regulatory authorities are necessary, they are not in themselves sufficient to ensure that commissions can effectively and proactively guide utilities in the complex task of phasing in new energy technologies while phasing out fossil fuels. New regulatory principles and frameworks may be necessary to address the rapidly changing energy landscape and new market conditions while aligning regulatory decision making with state climate-related policy goals. A 2023 report from Advanced Energy United highlights this challenge and suggests that, "Longer-term, comprehensive gas planning is needed to help utilities chart a long-term, least-cost, least-risk approach to decarbonization and avoiding path dependency that is incompatible with state policy."[184]

The Massachusetts Department of Public Utilities (DPU) is an example of a commission grappling with establishing and communicating to utilities new regulatory principles and a framework for transitioning the gas system. In its final order in the state's Future of Gas proceeding, the DPU articulates new "beyond gas" regulatory principles to guide its proceedings. The DPU emphasizes that, while the new framework is not intended to jeopardize gas utilities' rate recovery of existing assets, "a different lens will be applied to gas infrastructure investments going forward." Specifically, the DPU states it will be examining the usefulness of new investments in light of the Commonwealth's climate policy and "will be exploring and implementing policies that are geared toward minimizing additional investment in pipeline and distribution mains and achieving decarbonization in the residential, commercial and industrial sectors."[185]

A key regulatory tool needed to embark on a managed gas transition is dynamic, comprehensive long-term gas planning. In Illinois, the ICC has taken a major step forward by requiring gas utilities to file a Long-Term Gas Infrastructure Plan (LTGIP) with the Commission beginning in 2025 and every two years thereafter. Historically, Illinois investor-owned gas utilities have not been required to file comprehensive capital investment forecasts. As a result, the public has had only limited insight into these investments and their consequences for ratepayers. In addition, gas utilities in Illinois have not integrated electrification forecasts into their gas planning, instead arguing that there is insufficient

182 Nicolas Wallace et al., *Removing Legal Barriers to Building Electrification, Stanford Law School and Stanford Woods Institute for the Environment* (2020), p. 24, https://law.stanford.edu/wp-content/uploads/2020/10/2020-10-20_Natural-Gas-Memo_formatted.pdf.

183 Notably, the ICC does appear to have such directives with respect to electric services. See (220 ILCS 5/) Public Utilities, Article IV, https://www.ilga.gov/legislation/ilcs/ilcs3.asp?ActID=1277&ChapAct=220%26nbsp%3BILCS%26nbsp%3B5%2F&ChapterID=23&ChapterName=UTILITIES&ActName=Public+Utilities+Act%2E

184 Brad Cebulko and Thomas Van Hentenryck, *A Regulator's Blueprint for 21st Century Gas Utility Planning* (December 2023, prepared by Strategen for Advanced Energy United), p. 17.

185 MA DPU, Order on Regulatory Principles and Framework, DPU 20-80-B (December 6, 2023), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602.

evidence that electrification is imminent in their gas territories and, therefore, that it would be imprudent to incorporate displaced gas consumption scenarios into their planning.[186] The establishment of the LTGIP is an essential starting point for developing a comprehensive approach to long-term gas planning in Illinois.

Outmoded obligation to serve and energy services definitions

The so-called "obligation to serve" statute impedes the transition away from gas and toward clean energy in Illinois as well as many other states. This legal principle, initially established in common law by courts and later codified by many state legislatures, mandates that utilities must provide service to all customers within their service territories at regulated rates with limited exceptions. Cases like Montgomery Ward & Co. v. N. Pac. Terminal Co. of Or., 128 F. Supp. 475 (1953) and United Fuel Gas Co. v. R.R. Comm'n of Kentucky, 278 U.S. 300 (1929) articulate how the principle has been applied for decades.

In Illinois, the obligation to serve is codified in the Illinois Compiled Statutes as: "A public utility shall furnish, provide, and maintain such service instrumentalities, equipment, and facilities as shall promote the safety, health, comfort, and convenience of its patrons, employees, and public and as shall be in all respects adequate, efficient, just, and reasonable."[187] While the obligation to serve in Illinois does not specify a right to receive gas service, it has functioned this way to date.

A desire for greater clarity around the obligation to serve has led to a growing movement to modify it. Advocates in Washington, California, and New York, for example, are attempting to revise their statutes in a number of different ways, including: ensuring the obligation is aligned with the state's emissions reduction commitments; clarifying that electricity and/or thermal energy serve as adequate substitutes for gas; and clarifying that the utility's obligation to serve relates to energy services—heat, light, power—and not specifically to methane gas or any other fuel. BDC's recent report, "Decarbonizing the Obligation to Serve" explores why legislative clarity may be needed to ensure that this fundamental protection of access and service does not inadvertently prevent neighborhood-scale building decarbonization.[188]

Lack of coordinated gas and electric planning and alternative rate designs

Traditionally, the regulation of gas and electric utilities has been conducted under separate frameworks, and, even within dual-fuel utilities (i.e., a utility providing both gas and electric services), gas and electric operations and planning are often siloed. An effectively managed gas transition will require a high degree of coordination between gas and electric utilities, and utility commissions will want to identify the interactive effects for gas and electric customers and the implications for capital investment plans. An ideal managed transition might take "a whole-system approach where cost is optimized based on energy demand, inclusive of the electric and gas systems."[189] Short of that, gas and electric utilities could use the same assumptions regarding electrification (e.g., costs, technologies, efficiencies, grid impacts), load forecasts, and customer attrition and additions. (There are several options for syncing planning inputs and modeling depending on whether the utilities are dual-fuel or not.)[190]

A further area for policy development is alternative rate designs. In general, electricity has lower social costs than gas, a leverage point for reforming retail electricity rates in order to drive the adoption of heat pumps and electric vehicles, and to support the reduction of electricity usage at peak times.[191]

186 ICC, 2023 Rate Case for Ameren, Final Order (November 16, 2023), pp. 31, 69, https://www.icc.illinois.gov/docket/P2023-0067/documents/344282/files/601209.pdf.

187 220 ILL. COMP. STAT. 5/8-101. https://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=022000050K8-101

188 Kristin George Bagdanov, *Decarbonizing the Obligation to Serve*, Building Decarbonization Coalition (March 2024), https://buildingdecarb.org/decarbnation-obligation-to-serve.

189 Brad Cebulko and Thomas Van Hentenryck, *A Regulator's Blueprint for 21st Century Gas Utility Planning* (December 2023, prepared by Strategen for Advanced Energy United), p. 57. https://blog.advancedenergyunited.org/reports/regulator_blueprint_gas_utility_planning.

190 Ibid., pp. 53-56.

191 Tim Schittekatte et al., "Reforming retail electricity rates to facilitate economy-wide decarbonization," *Joule* (May 2023). https://doi.org/10.1016/j.joule.2023.03.012

Two states that have made significant strides in this direction are California and Hawaii. Using data on gas and electricity usage for residential customers of an investor-owned utility in the United States, a 2022 study finds that, by reforming the traditional cost-based rate design consisting of a fixed charge and flat volumetric charge, the operating cost gap between heat pumps and natural gas heating flips for all consumers from positive to negative. Switching to a time-of-use day/night structure or a demand-based structure results in even larger negative operating cost gaps: "These results reflect the fact that all of the alternative rate designs are better aligned with the marginal cost of generating and delivering power, compared to the default residential rate design, which typically is not."[192]

Impact of gas transition on organized labor

Gas distribution systems at the state level are maintained, serviced, and repaired by thousands of skilled trade workers. These workers also serve as critical first responders when explosions or other incidents occur. Some work directly for the gas utilities and others are employed by contractors that gas utilities engage to perform various projects. The future of the gas system is of critical importance to these workers and these workers are of critical importance to the future of gas. Below is a non-exhaustive list of leading labor groups in Illinois impacted by the future of gas:

- **Utility Workers Union of America** (UWUA), AFL-CIO represents 45,000 members in 22 states who are employed in utility sectors including gas, electric, water, wastewater, and municipal sectors.
- Within the **United Steelworkers** (USW), steelworkers fabricate pipes for the oil and gas industries and work on water, sewer, and utility lines as well as in residential plumbing, heating, and air conditioning. In the green energy economy, they also fabricate windmills and solar panels.[193]
- Trade occupations within the **United Association** (UA) related to the gas distribution industry include pipefitters, pipeliners, plumbers, steamfitters, welders, pipelayers, and control and valve installers and repairers.[194] These occupations are critical to the gas industry but also are relevant to industries such as commercial and industrial, fabrication, fire protection, industrial, residential, and medical and pharmaceutical.
- In Chicago, the **International Union of Operating Engineers** Local 150 is contracted to assist Peoples in its leak-prone pipe replacement efforts. Local leadership has recently spoken out regarding the impact that curbing pipeline replacement projects could have on membership.[195]

Organized labor has voiced concerns about potential job displacement due to measures that might limit gas industry capital spending on distribution infrastructure or mandate building electrification.[196] In Illinois, for example, the UWUA filed a response in support of Peoples' motion for a rehearing of the ICC's recent rate case order in which the ICC put a pause on about $260 million in further capital investments pending an investigation.[197] At the same time, positive labor support has been expressed for some alternative energy products, such as networked geothermal projects[198] and increased spending on gas line repairs.

192 Sanem Sergici et al., *Heat Pump-Friendly Cost-Based Rate Designs, A White Paper from the Retail Pricing Task Force*, Energy Systems Integration Group (2022), p. 16. https://www.esig.energy/heat-pump-friendly-rate-designs/

193 Nationwide, the United Steelworkers Union represents 1.2 million workers in the U.S., Canada, and the Caribbean. See https://www.usw.org.

194 Nationwide, the United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry represents more than 373,000 skilled journeymen and apprentices. See https://ua.org/.

195 Andrew Adams, "Peoples Gas Pushes Back Against State Oversight, Asks for Further Rate Increase" *WTTW News*, (December 8, 2023), https://news.wttw.com/2023/12/08/peoples-gas-pushes-back-against-state-oversight-asks-further-rate-increase.

196 Utility Workers Union of America. "Re: Oversight Hearing on Building Electrification, T-2021-8116," November 17, 2021. https://uwua.net/wp-content/uploads/2022/09/111721-electrification-nycitycouncil-1.pdf.; Utility Workers Union of America. "Re: Interim Clean Energy and Climate Plan for 2030 (2030 CECP) Comment from Utility Workers Union of America," March 22, 2021. https://uwua.net/wp-content/uploads/2022/09/032221-climateplan-ma-energyandenvaffairs.pdf.

197 Docket No. 23 - 0069 and Docket No. 23 - 0068. "Response Of The Gas Workers Union Local 18007, Utility Workers Union Of America, Afl-Cio To Verified Application For Rehearing Of North Shore Gas Company And The Peoples Gas Light And Coke Company" (IL. Commerce Commission). https://www.icc.illinois.gov/docket/P2023-0069/documents/345786/files/603685.pdf.

198 Utility Workers Union of America. Re: Boston Gas Company d/b/a National Grid – Geothermal Energy Demonstration Program Implemen-

New collaborative ventures are forming, such as the Climate Jobs National Resource Center (CJNRC) and its Illinois Chapter, Climate Jobs Illinois. The CJNRC is "advocating for bold clean energy investments with comprehensive labor standards—including prevailing wage, apprenticeship requirements, labor peace agreements, project labor agreements, and responsible bidder requirements."[199] These organizations and their memberships are crucial to a clean energy transition and greater effort is needed to better analyze, understand, and communicate the effects of a gas transition on organized labor.

While potential job loss has received significant attention from both lawmakers and unions, attention should also be given to the concern that a gas transition may result in a skilled labor shortage for gas workers. A trained workforce will be needed to safely maintain the system and also to safely decommission existing gas mains and service lines once an area has been completely electrified. As one study cautions: "mid-transition design should recognize and include the need to attract and retain skilled workers to operate the declining system as long as they are needed."[200] As such, far from a need for retraining the existing workforce, states should focus on workforce development programs that are additive to existing capabilities, such as training future pipeline workers on individual and networked thermal energy projects since these are likely to be a source of demand for skilled pipe-related occupations. Regardless of what the future holds, it is critical that the existing skilled workforce be part of a comprehensive transition strategy for each utility that creates the incentives needed to maintain the necessary skilled workforce while establishing a variety of bridges for younger workers.

> **"Greater effort is needed to better analyze, understand, and communicate the effects of a gas transition on organized labor."**

Equity, environmental justice, and affordability concerns

Low-income and environmental justice communities across the country are often subject to disproportionate gas system leaks and health and environmental burdens related to fossil fuel infrastructure. On top of this, many low-income households experience significant energy burdens and energy insecurity because basic services are so difficult to afford. Finally, these households often lack equitable access to the new generation of clean, energy efficient equipment and appliances and to programs and services that address poorly insulated spaces and neglected structural repairs. Many low-income families have no choice but to continue using utility gas and have few options as long as "fuel switching" from fossil fuel to electric equipment is not permitted under the state's utility energy programs.

A managed transition off gas must, in a comprehensive way, address all three interrelated challenges: environmental justice, affordability, and equity. While an unmanaged gas transition is likely to exacerbate each element, a managed transition offers a once-in-a-generation opportunity to significantly advance all three. Important components of a comprehensive plan include:

- Targeted pipeline decommissioning and electrification or TEN projects selected on the basis of screening criteria that prioritize EJ and low-income neighborhoods. Shifting away from accelerated pipeline replacement to strategic gas pipeline decommissioning can enhance public

tation Plan (D.P.U. 22-62), " July 29, 2022. https://uwua.net/wp-content/uploads/2022/09/072922-geothermal-ma-depofpubutilities.pdf.

199 Climate Jobs National Resource Center, "Climate Jobs Illinois," https://www.cjnrc.org/illinois/.

200 Emily Grubert and Sara Hastings-Simon, "Designing the mid-transition: A review of medium-term challenges for coordinated decarbonization in the United States," *WIREs Climate Change* (2022), p. 9, https://wires.onlinelibrary.wiley.com/doi/10.1002/wcc.768.

safety and health now while also mitigating climate damage.

- "One-stop shop" platforms that provide a full-service approach to coordinating needed retrofit and electrification services, organizing layered service delivery, and assisting residents with accessing rebates and incentives.
- Inclusive utility financing programs (tariff on-bill financing) that help customers pay for upgrades that will pay for themselves through energy savings over time.
- Income-discounted energy service rates that help lower household energy burdens by ensuring that energy costs don't exceed a certain threshold level.

Illinois has already made significant strides on a discounted rate approach for low-income households for gas and electrical services. It has also established a planning process for beneficial electrification, including a program permitting customers to finance energy efficiency upgrades through their utility bills.[201]

Conclusion

State energy systems across the country are in the midst of large-scale change and transition as different sectors and industries begin to shift away from fossil fuels to cleaner, decarbonized alternatives. Speed and direction are clearer for some industries than others, and some sectors face more uncertainty than others. The downsizing of the gas system per se is admittedly one of the most difficult and complex parts of this transformation. One reason is that the gas transition involves "phasing out," which is more difficult than the bulk of the rest of the overall transition, which is about "phasing in."[202] Additionally, gas utilities are experienced at managing investment for the long-term and not for periods of rapid or discontinuous change. Finally, it is likely that there will be a period (perhaps several decades long) during which the gas system and zero-carbon systems must co-exist and make mutual accommodations.[203]

> **"A managed transition off gas must, in a comprehensive way, address all three interrelated challenges: environmental justice, affordability, and equity."**

Strong policymaking and leadership are needed to develop and put in place a long-term plan for moving Illinois beyond gas. This will require minimizing investments in the gas pipeline system while simultaneously carrying out a phased, targeted retirement of parts of the system, all while switching out gas connections for electrified and decarbonized heating, cooling, and cooking technologies. While all challenges along the path cannot be foreseen, we have identified a number of likely barriers and obstacles to which policymakers and regulators must direct their attention. One of the most important objectives is to align the incentives faced by all actors so that efforts can pull in the same direction in response to the same price and other signals.

The journey towards a decarbonized Illinois is underway, marked by opportunities for innovation and collaboration. By aligning policies and actions, Illinois can ensure a smooth transition to a cleaner energy system, benefiting all residents with a focus on affordability and equity.

201 See Figure 2.2.

202 Emily Grubert and Sara Hastings-Simon, "Designing the mid-transition: A review of medium-term challenges for coordinated decarbonization in the United States," *WIREs Climate Change* (2022), https://wires.onlinelibrary.wiley.com/doi/10.1002/wcc.768.

203 Ibid.

Appendices

Appendix A: Modeling Methodology

This appendix describes the approach we taken by this report to project the revenue requirements of the Big Four gas utilities. Revenue requirement refers to the revenue that the utility needs to cover the expenses it expects to incur plus a financial return on its investments to utility shareholders. We seek to understand how the revenue requirement is likely to change over time as capital spending on gas plant increases or decreases and as the customer base of the utility either stays the same or shrinks. We measure the bill impact on ratepayers by calculating the per customer revenue requirement and then tracking that variable over time.

Methodology and analytical approach

Our revenue requirement modeling approach includes both the capital-related costs of utilities and operations-related costs—in other words, we project a full revenue requirement that includes the sum of total return on the utility's gas plant rate base, depreciation, operations and maintenance, and property taxes.

We include the following capital cost components of the revenue requirement:

- Allowed rate of return on rate base (weighted average cost of capital (WACC) for debt and equity)
- Depreciation rates (constructed as a weighted average for the main types of gas plant assets)
- Retirement rates (constructed as a weighted average for the main types of gas plant assets)
- Net salvage rates (constructed as a weighted average for the main types of gas plant assets)
- Property taxes
- Gross-up for state and federal income taxes and bad debt

Gas asset depreciation is determined by three main components: asset service life, net salvage value, and the method of depreciation. Asset service life refers to the period over which an asset is expected to be available for use by the gas utility (its "useful life"). An asset's useful life may be shorter than its physical life. Much of the gas plant investments in Illinois over the past ten years as well as current and planned investments have depreciation schedules that extend more than 60 years. Net salvage represents the expected cost recovery needed to remove the pipeline at the end of its service life. (For pipeline, net salvage is typically a negative value because the cost of removing the pipe at the end of its useful life exceeds the scrap or "salvage value" that the utility can recover.) For the method of depreciation, this study assumes straight-line depreciation, an industry standard. The longer the depreciation schedule the higher the total rate of return to be collected.

Depreciation, net salvage, and the methods for calculating these values are subject to the expected amount of pipeline retirements each year, which could change from historical precedents in the face of increased competition to and departure rates from the gas system.

The cost of capital is equal to the return on the rate base (adjusted for the gross-up and property taxes) multiplied by the rate base net of accumulated depreciation, retirements, and net salvage value. The rate base itself is equal to the original cost of the gas utility's gas plant.

Operations and maintenance expenses include expenses such as conducting leak surveys, repairing pipeline and meters, right of way surveys, emergency responses to gas odor calls, and general and administrative expenses. It also includes supplies and labor not used for plant construction. After conducting a trend analysis of these expenses, we assume a 3.5 percent annual rate of growth for each utility. Actual trends ranged from 3 to 8 percent.

Capital expenditures include spending on four types of gas plant: distribution, transmissions, storage,, and general plant. On an annual basis, total actual capital expenditures can vary considerably. We conducted several different kinds of trend analysis for the period 2015 to 2022. Even with large year-to-year swings in annual spending, CapEx for each gas utility shows a positive linear trend, ranging from 4 percent for North Shore to 11 percent for Nicor (for more information, see the "System growth" section of each company's profile). For example, Peoples' spending trend—as shown in Figure 3.9—exhibits large swings, but the trend over time is still positive; North Shore's 2022 spending was below its 2015 spending but the trend over time is nonetheless positive. For 2023 capital spending levels, we use the figures provided by each utility for "Gross Additions" found in Schedule B-5, a required rate case filing. We set the starting 2024 CapEx value equal to the 2023 value less the percent difference between the proposed and final revenue requirements for each company. For our business-as-usual modeling scenarios, we assume a 6 percent year-over-year increase in capital spending based on the historical trend analysis described above.

Our analytical approach relies on four steps:

1. **Develop capital cost and rate base projections for each company.** We use data on plant additions from each company obtained from utility filings with the ICC to examine historical trends in plant additions.
2. **Estimate the annual revenue requirement needed to cover each gas utility's capital spending plus related capital costs and operating expenses.** We rely on the Commission's 2023 rate case orders and related rate case filings to determine our initial base year variables.
3. **Estimate the average utility delivery cost per customer served under various capital investment and customer base scenarios.** Using our annual revenue requirement projections, we calculate the estimated per customer revenue requirement (i.e., the total revenue requirement in each year divided by the total customer base). Our estimates of per customer revenue requirements serve as a consistent, normalized metric for assessing the bill impact to ratepayers.[204]
4. **Calculate the value of unrecovered gas plant balances ("book value").** An unrecovered balance refers to gas assets that have been put into service but have not yet been fully recovered through rates. This balance consists of investments that are still being "recovered" through rates and therefore are not yet fully depreciated. This variable serves as our metric for capital asset risk exposure.

We use 2024 as the initial year for our modeling, and then project the annual revenue requirement in future years. There is no markup for inflation and all of our figures are expressed in nominal dollars. It should be noted that our modeling approach implicitly assumes that steady rate increases occur but, in reality, rate increases occur

204 An alternative approach is to estimate the future typical customer bills (gas supply charge plus fixed and variable delivery charges) that will be developed through the regulatory ratemaking process.

at intervals coinciding with rate cases proceedings before the ICC.

Data sources and initial values

For each gas utility, variables for the modeling and initial values were sourced as follows:

Variable (all for 2024 unless otherwise noted)	Source
Rate base	2023 ICC Rate Case Final Orders - Appendices
Capital expenditures (for distribution, transmissions, storage, intangible, and general plant)	Starting 2024 value calculated as Gross Additions from Schedule B-5 (a required filing for Rate Cases) for 2023 less the percent difference between Proposed and Final Revenue Requirements
Accumulated depreciation	2023 ICC Rate Case Final Orders - Appendices
Depreciation, retirement, and net salvage rates	Gas utility depreciation studies filed in 2023 Rate Cases
O&M net of production expenses	2023 ICC Rate Case Final Orders - Appendices
Property/real estate taxes	2023 ICC Rate Case Final Orders - Appendices
Capital structure	2023 ICC Rate Case Final Orders (section on Cost of Capital)
Weighted average cost of capital	2023 ICC Rate Case Final Orders (section on Cost of Capital)
Gross revenue conversion factor	2023 ICC Rate Case Final Orders - Appendices
Number of customers	2023 Rate Case filing Schedule E-5 (Jurisdictional Operating Revenue)
Trends in capital expenditures on gas plant	Calculated from “Gas Plant in Service” in ICC Form 21 ILCC (Annual Report of Electric & Gas Utilities), 2015 - 2022
Trends in O&M	Calculated from “Gas Operation and Maintenance Expenses” in ICC Form 21 ILCC ((Annual Report of Electric & Gas Utilities), 2015 - 2022

Appendix B: Data Sources for Big Four Gas Utility Profiles

Gas infrastructure

Miles of mains by decade installed and counts of distribution main miles and services: GWD analysis of PHMSA Form 7100.1 for distribution mains and services.

Miles of transmission mains: ICC Annual Report 2022 to ICC, Form 21 ILCC.

Storage field counts: Information found on company websites or in required 2023 Rate Case testimony by company staff.

Customers per mile of distribution main: For customer data, see ICC, Comparison of Gas Sales Statistics for 2022. For miles of distribution main, see PHMSA, Form 7100.1 for 2022.

Spend per mile of distribution main installed: For Ameren and Nicor, calculations by GWD based on 2023 Annual QIP Plan Update (Docket Nos. P2014-0573 and P2014-0292, respectively). The QIP updates present expected year-end miles installed and total cost; it is unclear whether they include the cost of main retirement and whether they are fully loaded costs. For Peoples, see 2023 Q4 System Modernization Report. Note: the two values correspond to year-to-date costs of main install in two subprograms of the SMP (Neighborhood Program and the Public/System Improvement Program, respectively) and do not include the costs of main retirement.

Replacement priorities: See company testimony in 2023 Rate Cases related to Schedule F-4.

System growth

Annual capex, total spending by category, and gas plant capital spending: GWD analysis of Annual Reports for 2022 filed with the ICC (Form 21 ILCC), "Gas Plant in Service", 2014-2022

Average year-over-year growth, increase in value of gas plant, and gas system CapEx in 2022: GWD calculations based on Annual Reports for 2022 filed with the ICC (Form 21 ILCC), "Gas Plant in Service", 2014-2022.

Customers

Customers and therms by category: GWD analysis of "Jurisdictional Operating Revenue," Schedule E-5 from 2023 Rate Case dockets for each gas company, test year 2024.

Total growth since 2000 and average annual growth since 2000: GWD analysis of ICC Comparison of Gas Sales Statistics, various years.

Total customers: GWD analysis of ICC Comparison of Gas Sales Statistics, 2022.

Residential customers: GWD analysis of "Jurisdictional Operating Revenue" (present revenue by delivery service classification for test year 2024), Schedule E-5 from 2023 Rate Case dockets for Ameren, Nicor, North Shore, and Peoples.

Estimated average annual delivery cost per customer in 2023: GWD revenue requirement modeling (see Section 5 and Appendix A)

Total bill assistance received from public programs and rate riders in 2021: ICC Low-Income Discount Rate Study Report to the IL General Assembly, December 2022, Table III, p. 12.

Residential customers charged late fees and total arrearages in January 2024: 2024 Monthly Filings for each utility at ICC's website for Credit, Collections, and Arrearages Reports.

Cost projections and unrecovered gas assets

Average delivery costs per customer, unrecovered gas assets, and revenue increase needed: GWD modeling (see Section 5 and Appendix A)

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