BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE	*	
PETITION OF THE OFFICE	*	
OF PEOPLE'S COUNSEL FOR	*	
NEAR-TERM, PRIORITY ACTIONS	*	CASE NO.
AND COMPREHENSIVE,	*	
LONG-TERM PLANNING FOR	*	
MARYLAND'S GAS	*	
COMPANIES	*	

PETITION OF THE OFFICE OF PEOPLE'S COUNSEL FOR NEAR-TERM, PRIORITY ACTIONS AND COMPREHENSIVE, LONG-TERM PLANNING FOR MARYLAND'S GAS COMPANIES

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PETITION OF THE OFFICE OF PEOPLE'S COUNSEL FOR NEAR-TERM, PRIORITY ACTIONS AND COMPREHENSIVE, LONG-TERM PLANNING FOR MARYLAND'S GAS COMPANIES

To further its mandate to protect the interests of residential utility customers and the State's progress toward meeting State greenhouse gas emissions reduction goals,[1] the Office of People's Counsel respectfully requests that the Public Service Commission initiate a proceeding to address the planning, practices, and future operations of the gas public service companies (the "gas companies") to ensure they are consistent with the "interest of the public"[2] and that the rates they charge utility customers are and continue to be "just and reasonable."[3] The gas companies' escalating capital spending on infrastructure—as well as their procurement, line-extension, marketing, and EmPOWER practices, among others—are misaligned with technological and economic trends toward the replacement of fossil gas with electricity, Maryland's greenhouse gas reduction goals, and Maryland's evidence-backed policy to convert buildings to electricity to meet the challenge of climate change. Left unaddressed, this misalignment will have significant adverse consequences for Maryland's residential customers and utilities, including possible financial responsibility for tens of billions of dollars of utility assets that are "stranded" because market forces render them unused or cause their early retirement.

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[1] Md. Code Ann., Pub. Util. Art. ("PUA") § 2-204(a). OPC also files this petition in response to the Commission's notice dated October 6, 2021, seeking comment regarding the Commission's newly established statutory obligation to expressly consider the "protection of the global climate…[and] the achievement of the State's climate commitments for reducing statewide greenhouse gas emissions" in the exercise of its duties. *Notice of Consideration of New Statutory Factors*, Maillog No. 237335 (Oct. 6, 2021) (quoting PUA § 2-113(a)(2)(v)-(vi) (added by 2021 Md. Laws Chs. 614 & 615)).

[2] PUA § 2-113(a)(1)(i).

[3] PUA §§ 4-101, 4-102(b), 4-201.

Allowing these practices to continue unchecked conflicts with the Commission's obligations to (i) "supervise and regulate" the gas companies to "ensure their operation in the interest of the public"[4] and that their rates are "just and reasonable;"[5] and to (ii) consider "the preservation of environmental quality, including protection of the global climate … and the achievement of the State's climate commitments for reducing statewide, greenhouse gas emissions."[6]

The natural gas distribution industry in Maryland is at a point in time where the usual progression of traditional cost-of-service regulation will lead to massive rate increases or an unviable business model for the utilities, leaving both gas customers and gas utilities at tremendous risk. The Commission should act now in an open and transparent proceeding to gather the information it needs to determine what regulatory actions should be taken immediately and over the long term to mitigate the risks associated with the untenable mismatch between escalating capital investments and declining sales. The General Assembly has signaled its "support [for] moving toward broader electrification of both existing buildings and new construction as a component of decarbonization,"[7] and even the State's largest gas utility anticipates reductions in gas delivered on its system of at least 60 percent,[8] yet the Commission has no forum to

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[4] PUA § 2-113(a)(1)(i).
[5] PUA §§ 4-102(b), 4-201.
[6] PUA §§ 2-113(a)(2)(v)-(vi).
[7] *See, e.g.*, Climate Solutions Now Act of 2022 ("CSNA") §§ 10(a)(1)-(2), 2022 Md Laws Ch. 38.
[8] Energy and Environmental Economics ("E3"), *BGE Integrated Decarbonization Strategy* (Oct. 2022), at 25, https://www.bge.com/SafetyCommunity/Environment/Documents/BGE%20Integrated%20Decarbonization%20White%20Paper_FINAL%202022-10-06.pdf.

examine the potential reductions in gas use and the resulting impact on gas customers' rates. A gas utility proceeding—with two tracks, one for long-term planning and another for priority actions that do not need extensive investigation and fact-finding—will mitigate the challenges facing both gas customers and gas utilities as costs rise and sales decline.

For the reasons set forth in this petition, OPC requests that the Commission initiate a two-track proceeding to address these issues proactively and comprehensively. On one track, the Commission should establish an open and transparent investigation to make findings on gas usage reductions, potential rate impacts, and related operational and financial matters caused by the transition to electrification, as well as issue guidance on regulatory strategies to reduce the costs and risks for gas customers. We will refer to this as the "Transition Track." The Transition Track would lead to the adoption of regulations governing gas utility transition plans and the Commission's oversight of those plans. Once those regulations are adopted, the utilities would file their individual transition plans for public comment. The Commission then would review those plans and oversee implementation for the individual gas utilities.

On the other track, the Commission should address priority near-term actions. This "Priority Track" would identify actions that can be taken in the near-term based on the widely accepted fact that gas sales will decline because (i) technologies for electrifying many end-uses already are more cost-effective than continued gas use, and (ii) the State cannot meet its greenhouse gas reduction goals without substantially reducing fossil gas consumption, if not eliminating it altogether. This track should result in Commission orders requiring gas utilities to take actions in the near-term to reflect the projections of declining gas sales and align utility practices with the public interest and statutory requirements. As discussed in more detail in Part III.C below, these priority actions should, at a minimum, include modifying gas procurement practices, gas line extension policies, gas company marketing practices, and EmPOWER Maryland programs.

The two-track proceeding OPC requests in this petition is critical to ensuring that future gas utility operations and practices are consistent with the public interest and the law. Especially under the circumstances here, where the fundamental nature of an important utility service is changing, the public interest requires the Commission to proactively lead comprehensive industry reform. The Commission—rather than utility proposals—should set the agenda for the transition and guide a process that is robust, transparent, and inclusive of all stakeholders. The significant reforms, while urgently needed, should be well-planned, not subject to the timing of individual rates cases, and consistent across the State. This petition intends to assist the Commission with leading that process.

INTRODUCTION

Technological advances already have made electric heating and appliances more affordable than fossil gas for many building applications.[9] At the same time, the dire consequences of climate change are leading national, state, and local governments to

[9] *See* Part II.A below.

adopt ambitious climate polices that depend on the widespread electrification of end-uses, including the heating of buildings, that are now met mainly with fossil gas.[10] In enacting the Climate Solutions Now Act of 2022 (the "CSNA"), Maryland adopted some of the most aggressive goals in the nation, targeting economy-wide greenhouse gas ("GHG") emissions reductions of 60 percent (from a 2006 baseline) by 2031 and net zero GHG emissions by 2045.[11] Maryland cannot reach these targets without substantially reducing fossil gas use in buildings.[12] That substantial reduction in fossil gas use has major implications for the traditional business model of Maryland's gas companies.

The State's largest utility has acknowledged that its gas deliveries will decline by at least 60 percent to meet the State's climate goals.[13] Yet, instead of slowing capital spending to align with projected decreases in gas consumption, the gas companies continue to make, and even accelerate, new investment in their gas systems, locking in costs based on the fiction that the infrastructure investments will serve out their useful lives for the next 40 to 70 years—well beyond the time horizon for implementation of the State's GHG emissions reductions goals.[14] Eventually, gas customers, shareholders, or even taxpayers may have to pay for these stranded investments in new and replacement pipes that are no longer "used or useful"[15] for providing service.

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[10] *See* Part II.B below.
[11] CSNA §§ 3-4 (codified in relevant part at Md. Code Ann., Envir. ("EN") §§ 2-1201, 2-1204.1, 2-1204.2).
[12] *See* Part II.B.1 below.
[13] *BGE Strategy* at 25.
[14] *See* Part IV.A below.
[15] *See* PUA § 4-101.

Put simply, the gas companies' focus on rapid investment in fossil fuel infrastructure fails to account for the fact that customers have begun to switch from fossil gas to electricity, a trend that will accelerate as every level of government acts to achieve its climate goals.[16] The decline in the volume of gas that gas companies distribute means that rates have to increase for remaining gas customers to defray the gas companies' fixed costs over a smaller customer base. This scenario is economically unsustainable, and gas companies may face challenges in funding the basic system maintenance needed to ensure they can comply with their obligations to provide safe and reliable service.[17]

Advances in technology and the State's GHG reduction policies necessitate immediate State action to ensure that the gas companies' planning, processes, and future operations align with economic and technological realities and the State's plans for addressing the climate crisis. The Commission has the expertise, the legal authority, and the statutory obligation to investigate, make determinations, and issue guidance about anticipated supply and demand developments, including a shrinking gas system; investment recovery; and customer impacts—all of which are intrinsically tied to technological trends toward electrification and the State's GHG emissions reduction targets.[18] The Commission's diligent pursuit of the dual-track proceeding presented here is urgently needed to ensure that utilities take both short- and long-term actions to provide safe and adequate service to customers at just and reasonable prices, to provide a

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[16] *See* Part II.B below.
[17] *See* PUA §§ 5-303, 2-113.
[18] *See* Part I below.

forum for fact-finding and guidance to the Maryland legislature and other State and local agencies, and to assist the gas companies and their customers in planning for the coming transition.

ARGUMENT

This petition proceeds in five primary parts. **Part I** identifies the Commission's existing authority to initiate proceedings regarding gas utility operations and transition planning. **Part II** explains how technological advances and climate policy are jointly rendering the gas distribution business a declining industry. **Part III** explains how the gas companies' current practices are misaligned with these realities, putting customers at risk and implicating the Commission's statutory obligations. **Part IV** explains how a failure of the Commission to engage in long-term planning is to defer to the gas companies' private interests over the public interest. **Part V** highlights some of the extensive guidance available to the Commission in designing the requested proceedings. In several **appendices**, we provide potential questions to be addressed for transition planning, a proposed order, a summary of other states' related proceedings, and OPC's two recent gas utility reports that are discussed below.

I. The Commission has authority to investigate and reform gas company planning, practices, and operations.

The transition to clean energy is changing the business and economic environment in which the gas companies operate,[19] but the gas companies continue to operate largely as if change is not happening,[20] placing the companies and their customers at risk.[21] This increasing misalignment between the utilities' practices and the implications of technological change and climate policy implicates many, if not all, of the Commission's core obligations and authorities to supervise, oversee, and regulate the gas companies under its jurisdiction.

Foremost, the Commission has the duty to "supervise and regulate" the public service companies to "ensure their operation in the interest of the public."[22] In 2021, the General Assembly directed that in carrying out this legislative directive, the Commission "*shall* consider" the "preservation of environmental quality, including protection of the global climate from continued short-term and long-term warming based on the best available scientific information recognized by the Intergovernmental Panel on Climate Change [IPCC]" and "the achievement of the State's climate commitments for reducing statewide, greenhouse gas emissions."[23] According to "the best available scientific information" that the Commission by law must consider, "limiting human-induced global warming … requires limiting cumulative CO_2 emissions, reaching at least net zero CO_2

[19] *See* Part II.A below.
[20] *See* Parts III.A, III.C below.
[21] *See* Part III.B below.
[22] PUA § 2-113(a)(1).
[23] PUA § 2-113(a)(2)(v)-(vi) (emphasis added).

emissions, along with strong reductions in other greenhouse gas emissions," such as CH_4, commonly known as methane,[24] the primary component of fossil gas.[25]

The Commission also has broad regulatory authority over the planning and business models of the public service companies subject to its jurisdiction. For example, the Commission is charged with setting "just and reasonable" rates for public service companies,[26] and it is tasked with mandating and approving "long-range plans" "formulate[d]" and "implement[ed]" by the public service companies "to provide regulated service."[27] The statute directs a broad interpretation of these express "powers and duties,"[28] and explicitly requires that "[t]he Commission *shall* initiate and conduct any investigation necessary to execute its powers or perform its duties."[29] Just as the Federal Energy Regulatory Commission ("FERC") has broadly interpreted its authority to set "just and reasonable rates" as authorizing the agency to reform long-term regional transmission planning,[30] the Commission's traditional statutory duties obligate the

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[24] IPCC, *Climate Change 2021, The Physical Science Basis, Working Group I Contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* (Aug. 7, 2021), at 27, https://www.ipcc.ch/report/ar6/wg1/.

[25] Fossil gas delivered by the gas companies to final customers is predominantly (92.8 percent) composed of methane. James Bradbury et al., *Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain- Sankey Diagram Methodology*, U.S. DEP'T OF ENERGY, OFFICE OF ENERGY POLICY AND SYSTEMS ANALYSIS (July 2015), at 6.

[26] PUA §§ 4-102(b), 4-201. *See also* PUA § 5-303.

[27] PUA § 2-118(b).

[28] PUA § 2-113(b) ("The powers and duties listed in this title do not limit the scope of the general powers and duties of the Commission.").

[29] PUA § 2-115(a) (emphasis added).

[30] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Docket No. RM21-17-000, 179 FERC ¶ 61,028 (Apr. 21, 2022). As FERC explained in its proposed rule, long-term planning—20 to 30 years into the future—lowers customer costs and brings customer benefits. *Id.* at 28-29. By contrast, the lack of effective long-term planning "is resulting in unjust, unreasonable, unduly discriminatory, and preferential" rates. *Id.*

Commission to initiate the proactive and comprehensive long-term planning this petition seeks.

The Commission itself has emphasized its "broad authority under PUA § 2-113 to regulate the activities of utility companies providing services within the State."[31] In finding it had authority to rule on the electric utilities' petition to invest in electric vehicle programs, the Commission observed that utility "infrastructure investments" are core services subject to the Commission's jurisdiction, and noted its obligation to consider "the economy of the State, the conservation of natural resources, and the preservation of environmental quality" when supervising and regulating public service companies—authority that since has been expanded to require consideration of the "global climate" and "the achievement of the State's climate commitments for reducing statewide greenhouse gas reduction goals."[32] In addressing Columbia Gas of Maryland's proposed Green Path Rider program in a recent administrative meeting, the Commission chair further emphasized that "the Commission has very broad jurisdictions, and even more so recently with respect to environmental matters involving its utilities."[33] These same observations apply with greater force to the gas utilities' current massive infrastructure spending programs and other policies that are misaligned with the State's policy goals.

Moreover, section 2-1305 of the Environment Article ("EN") requires that the Commission, like "each State agency," take certain additional actions to ensure that its

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[31] Order No. 88997, Case No. 9478 (Jan. 14, 2019), at 39.
[32] *Id.* at 39-40 (quoting PUA § 2-113(a)(2)).
[33] Pub. Serv. Comm'n, *Administrative Meeting – 01/18/23* at 1:26:11, https://www.youtube.com/watch?v=HFZybYciUsw.

operations align with the State's GHG emissions reduction goals. For example, the statute requires that the Commission "*shall* review its planning, regulatory and fiscal programs to identify and recommend actions to more fully integrate the consideration of Maryland's greenhouse gas reduction goal and the impacts of climate change"[34] and "*shall* identify and recommend specific policy, planning, regulatory and fiscal changes to existing programs that do not currently support the State's greenhouse gas reduction efforts or address climate change."[35] That subtitle further provides that the Commission "*shall* report annually on the status of programs that support the State's greenhouse gas reduction efforts or address climate change,"[36] and "when conducting long-term planning, developing policy, and drafting regulations," the Commission "*shall* take into consideration . . . [t]he likely climate impact of the agency's decisions relative to Maryland's greenhouse gas emissions reduction goals… ."[37]

In sum, effective planning produces better utility performance, saving customers money. Robust long-term planning is, therefore, fundamental to ensuring utility infrastructure investments are consistent with the public interest, and such long-term planning therefore falls well within the Commission's authority. Whether under its traditional duties to supervise and regulate public service companies or its updated mandate to consider the impacts of climate, the Commission has authority to reform gas company planning, practices, and operations so that they are consistent with substantial

[34] EN § 2-1305(a)(1) (emphasis added).
[35] EN § 2-1305(b) (emphasis added).
[36] EN § 2-1305(c)(1) (emphasis added).
[37] EN § 2-1305(d) (emphasis added).

declines in gas sales. Further, the Commission has jurisdiction to require the gas companies to take immediate actions—examples of which are described in Part III.C, below—to align utility practices with technological and economic realities, State policy, and customers' and the public's interests.

Finally, while the Commission's existing authority is substantial, proceedings on long-term gas utility planning and near-term priority actions could result in identifying measures for which additional statutory authority is necessary or desirable. Having initiated an investigation and proceeding, the Commission will be well-positioned to identify any matters for legislation and make appropriate recommendations to the General Assembly.

II. Technology, market trends, and climate policy are rendering the gas distribution business a declining industry.

This Part II explains how advances in technology, market trends, and climate policy are combining to make the traditional fossil gas distribution business obsolete. Part II.A explains that electric technologies are already driving changes to fossil gas consumption, regardless of climate policy. For buildings, the primary driver is highly efficient electric heat pump technologies for heating homes and water, although electric induction stoves are also improving and can be expected to reduce fossil gas market share, especially with growing awareness of the health effects associated with the indoor combustion of fossil gas. Part II.B explains how the reality of climate change, and the role of fossil gas, is driving policy at all levels of government that will further accelerate the transition from fossil fuels to electricity.

A. Technology is already driving customers to switch from fossil gas heating and appliances to electric ones.

Electrification technologies are increasingly rendering gas uncompetitive for many residential and commercial buildings. Electric heat pumps provide a prime example. Heat pumps provide both energy-efficient cooling and heating with far lower emissions than cooling with electricity and heating with gas.[38] The total cost of installing heat pumps in residential new construction is much less than the cost of installing fossil gas equipment for heat plus central air conditioning (AC) for cooling.[39] For retrofitting an existing building, the cost of installing heat pumps is similar to or less than the combined installed cost of the furnace and central AC.[40] A study by the Lawrence Berkeley National Laboratory (LBNL) found that, on average nationally, a new gas furnace and AC have a combined installed cost of almost $11,000 for residential retrofits. In contrast, the installed cost of heat pumps is substantially less, at just over $8,000.[41] Comparatively, a gas furnace cannot be used for home cooling and requires an additional system for AC.[42]

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[38] *See* Pistochini et al., *Greenhouse Gas Emission Forecasts for Electrification of Space Heating in Residential Homes in the US*, 163 ENERGY POLICY 112813 (Apr. 2022) (comparing emissions from heating with heat pumps to heating with gas furnaces).

[39] *See, e.g.,* Lacey Tan et al., *The Economics of Electrifying Buildings: Residential New Construction*, RMI (Dec. 2022), https://rmi.org/insight/the-economics-of-electrifying-buildings-residential-new-construction/.

[40] Synapse Energy Economics, Inc., *Climate Policy for Maryland's Gas Utilities: Financial Implications* (Nov. 2022), at 5, https://opc.maryland.gov/Gas-Rates-Climate-Report (attached as Appendix D).

[41] Brennan. D. Less et al., *The Cost of Decarbonization and Energy Upgrade Retrofits for US Homes*, LAWRENCE BERKELEY NAT'L LAB., https://escholarship.org/uc/item/0818n68p.

[42] For commercial heating and cooling systems, retrofit costs are harder to compare than for residential ones, because costs vary by building type and data are relatively sparse for the variety of building types in use for commercial applications. Some studies suggest that installed costs for heat pumps are comparable to the cost of gas heating and separate electric AC systems for commercial buildings. *See, e.g.*, Group 14 Engineering, *Electrification of Commercial and Residential Buildings* (Nov. 2020). For small commercial customers, E3's study for Maryland found that all-electric new construction is cheaper than mixed-fuel new construction due to lower capital and operating costs. E3, *Maryland Building Decarbonization Study:*

In the absence of extreme price volatility, operating costs, including fuel, are similar for these options.[43]

Growing consumer awareness of the health effects associated with the use of gas stoves is likely to further motivate consumers to make the switch from gas to electric. Although the scrutiny is not new,[44] recent research connecting the elevated levels of nitrogen dioxide produced by gas stoves with childhood asthma in the United States[45] has received widespread media attention.[46] The American Medical Association recently recognized the association between the use of gas stoves, indoor nitrogen dioxide levels,

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Final Report (October 20, 2021), https://mde.maryland.gov/programs/Air/ClimateChange/MCCC/Documents/MWG_Buildings%20Ad%20Hoc%20Group/E3%20Maryland%20Building%20Decarbonization%20Study%20-%20Final%20Report.pdf.

[43] *Md. Building Decarbonization Study.*

[44] *See, e.g.*, Weiwei Lin et al., *Meta-Analysis of the Effects of Indoor Nitrogen Dioxide and Gas Cooking on Asthma and Wheeze in Children*, 42 INT'L J. OF EPIDEMIOLOGY 1724 (Aug. 20, 2013) (providing quantitative evidence that gas cooking increases risk of asthma in children); Brady Seals & Andee Krasner, *Gas Stoves: Health and Air Quality Impacts and Solutions* (2020), RMI, PHYSICIANS FOR SOC. RESPONSIBILITY, MOTHERS OUT FRONT, AND SIERRA CLUB, https://rmi.org/insight/gas-stoves-pollution-health/ (synthesizing the last two decades of research and offering recommendations regarding the health risks associated with gas stoves).

[45] *See, e.g.,* Talor Gruenwald et al., *Population Attributable Fraction of Gas Stoves and Childhood Asthma in the United States*, 20(1) INT'L J. OF ENVTL. RESEARCH AND PUB. HEALTH 75 (2023) (finding that more than 12 percent of current childhood asthma cases in the U.S. can be attributed to gas stove use).

[46] *See, e.g.,* Maxine Joselow & Vanessa Montalbano, *Gas Stove Pollution Causes 12.7% of Childhood Asthma, Study Finds,* WASH. POST (Jan. 6, 2023), https://www.washingtonpost.com/politics/2023/01/06/gas-stove-pollution-causes-127-childhood-asthma-study-finds/; Ari Natter, *Ban on Gas Stoves Considered After New Study Draws Connection to Childhood Asthma*, BALT. SUN/BLOOMBERG NEWS (Jan. 9, 2023), https://www.baltimoresun.com/business/gas-stove-ban-20230109-rh27f73tmnabvg23723yjuazd4-story.html; Laura Baisas, *Gas Stoves Could Be Making Thousands of Children in America Sick*, POPULAR SCI. (Jan. 6, 2023), https://www.popsci.com/health/gas-stove-childhood-asthma/; Oliver Milman, *One in Eight Cases of Asthma in US Kids Caused by Gas Stove Pollution – Study*, THE GUARDIAN (Jan. 6, 2023), https://www.theguardian.com/environment/2023/jan/06/us-kids-asthma-gas-stove-pollution.

and asthma,[47] and the U.S. Consumer Product Safety Commission reportedly plans to open a proceeding to consider the hazards of gas stoves and potential solutions.[48]

Electrification is already occurring across the country. Between 2015 and 2020, the number of U.S. households using heat pumps for space heating doubled.[49] And based on a review of U.S. Census Bureau data, the Brattle Group concluded in a 2021 study that at then-current rates—i.e., before taking into account the effect of the 2022 federal Inflation Reduction Act—"the number of homes with electric space heating could exceed the number of homes with gas space heating by 2032" in some parts of the country.[50] Figure 1 shows that electrification is happening here in Maryland as the electric heating stock (mostly heat pumps) has been increasing for years now, while gas heating stock has stagnated.

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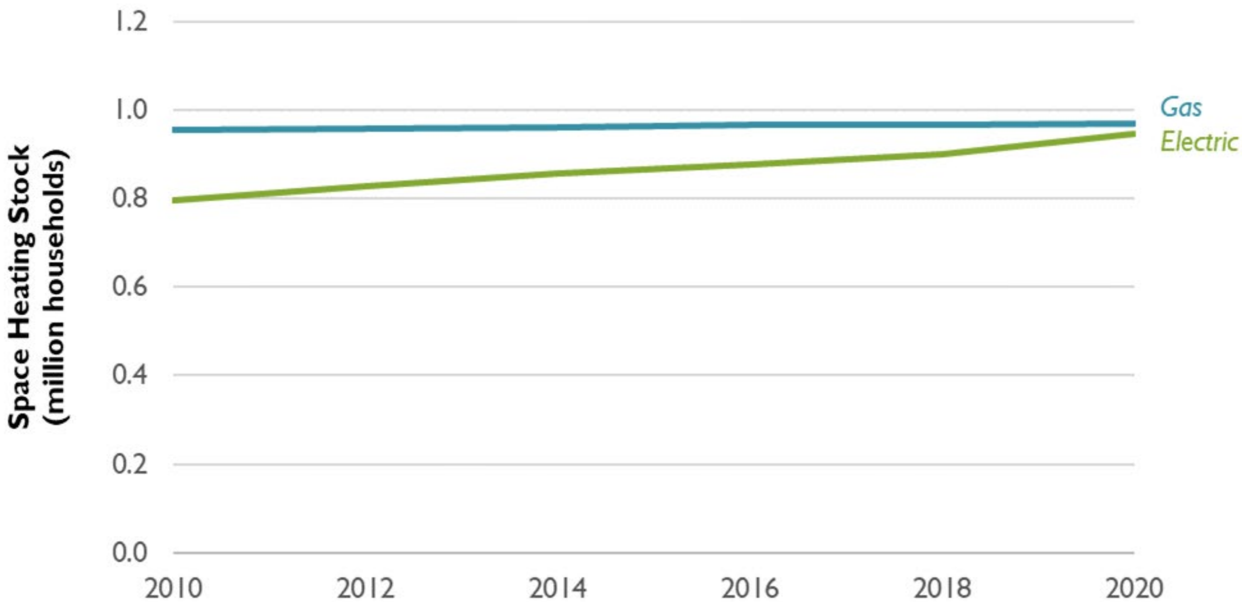
[47] Proceedings of the Am. Med. Ass'n's 2022 Annual Meeting of the H.D. - Resolutions, at 459 (Nov. 13, 2022), https://www.ama-assn.org/system/files/a22-resolutions.pdf.

[48] *See, e.g.,* Natter.

[49] *See* Ana Sophia Mifsud & Rachel Golden, *Millions of US Homes Are Installing Heat Pumps. Will It Be Enough?*, RMI (Nov. 1, 2022), https://rmi.org/millions-of-us-homes-are-installing-heat-pumps-will-it-be-enough/ (citing EIA Residential Energy Consumption Survey).

[50] Brattle Grp., *The Future of Gas Utilities Series: Transitioning Gas Utilities to a Decarbonized Future, Part 1 of 3* (Aug. 2021), at 9, https://www.brattle.com/wp-content/uploads/2022/01/The-Future-of-Gas-Utilities-Series__Part-1.pdf.

Figure 1. Gas and Electric Space Heating Stock in Maryland Households, 2010-2020 [51]



US Census Bureau: American Community Survey. Table DP04: Selected Housing Characteristics for Maryland, 5-year Estimates. June 2, 2022, available at: *https://data.census.gov/cedsci/table?q=DP04&g=0400000US24&tid=ACSDP5Y2020.DP04*

While the figure shows electric heating gradually eating into gas's market share through 2020, subsequent federal and State policy enactments will accelerate that trend.

B. Climate change policy will further drive the shift from gas to electricity.

Over the last decade, building electrification in Maryland has been driven largely by the economic benefits of highly efficient electric heat pump technology. In the decades ahead, electrification will accelerate dramatically due to an increasing number of governmental policies to address our changing climate.[52] The "best available scientific information"—which the law mandates the Commission to consider[53]—establishes the

[51] Figure 1 is taken from OPC's *Synapse Report* at 3.
[52] *Synapse Report* at 3-4.
[53] PUA § 2-113(a)(2)(v).

urgency of addressing greenhouse gas emissions. According to the world-wide scientific consensus developed under the auspices of the IPCC—the forum convened by the United Nations and the authority expressly relied upon by the Maryland General Assembly[54]—our climate, at world scale, is heating up at an accelerated pace and in an unprecedented manner.[55] Maryland is already experiencing these impacts.[56] Because of its extensive shoreline, Maryland is being and will be adversely impacted by sea-level rise, warming of coastal waters, severity of precipitation, and associated flooding, extreme heat events, and adverse public health impacts.[57] As described below, Maryland and federal buildings policy reflect this well-established science.

1. State policy strongly favors reduced gas consumption and looks to the Commission to guide the gas utility transition.

Carbon dioxide produced from the combustion of fossil fuels—including gas—is the main component of the GHG emissions that the IPCC and the State have targeted for

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[54] *Id.*
[55] *See generally 6th Assessment Report*; IPCC, *Climate Change 2022, Mitigation of Climate Change, Working Group III Contribution to Sixth Assessment Report* (Apr. 4, 2022), https://www.ipcc.ch/report/sixth-assessment-report-working-group-3/; *see also* U.S. Global Change Res. Program, *Fifth National Climate Assessment, Third Order Draft* (Nov. 7, 2022), https://review.globalchange.gov/ (discussing impacts in the US).
[56] *See generally,* Md. Comm'n on Climate Change ("MCCC"), *2022 Annual Report* at 27-29 (discussing the relevance of the IPCC's findings in Maryland); MCCC, *2021 Annual Report* at 20-26 (same).
[57] U.S. Nat'l Oceanic and Atmospheric Admin., Nat'l Ctrs. for Envtl. Info., State Climate Summaries (2022), *Maryland and the District of Columbia* (2022), available at https://statesummaries.ncics.org/chapter/md/ (describing projected increases in temperature, severity of precipitation and sea level rise in Maryland); Pl.'s Compl. 28-47, *Mayor and the City Council of Balt. v. BP P.L.C. et al.*, No. 24C18004219 (Balt. City Cir. Ct., July 20, 2018) (outlining through pleadings of fact, with extensive citations, the increased occurrence and future increased risk, driven by climate change, of sea-level rise, flooding, volatility in the hydrologic regime—leading to more droughts—temperature rise, extreme heat events, and adverse public health impacts in Maryland and in the City of Baltimore); MDE, *Greenhouse Gas Emissions Reduction Act: 2030 GGRA Plan* (Feb. 19, 2021), at 7-20, https://mde.maryland.gov/programs/air/ClimateChange/Documents/2030%20GGRA%20Plan/THE%202030%20GGRA%20PLAN.pdf (describing the impacts of climate change and "the cost of inaction" in Maryland).

reduction, and leaks from gas production, transmission, and distribution infrastructure increase the atmospheric concentrations of methane (CH_4). Both trap heat and increase atmospheric temperatures. Methane from fossil gas production and consumption is a particularly potent GHG—a fact the General Assembly recently recognized in changes to the State's GHG inventory tracking requirements.[58] According to the Maryland Department of the Environment's ("MDE") most recent report, the delivery of gas to end users is responsible for 16.68 percent of Maryland's statewide GHG emissions.[59]

Informed by this science, Maryland adopted a statutory framework aimed at reducing GHG emissions, including by reducing fossil gas use in buildings in favor of electricity.[60] The 2009 Greenhouse Gas Reduction Act ("GGRA") required a 25 percent

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[58] Although methane persists in the atmosphere for a shorter time than carbon dioxide, its relative warming impact is far greater. When combusted as an end-use by customers, 1 kilogram of fossil gas (both methane and non-methane components) is converted into 2.72 kilograms of emissions of carbon dioxide. U.S. DEP'T OF ENERGY at 16-17 (Appendix 3). When leaked without combustion into the atmosphere, however, methane has 84-86 times the global warming potential of carbon dioxide when evaluated over a 20-year period. Such fugitive methane emissions can occur up and down the stream of gas production and distribution and, in addition to combustion itself, are a necessary part of accounting for the industry's impact on overall emissions. Accurate translation of levels of CH_4 emissions into their CO_2 equivalent, associated with natural gas end-use consumption requires specification of which measure of global warming potential ("GWP") of CH_4 is utilized, based on metrics developed by the IPCC, and an estimate of the CH_4 leakage resulting from that consumption. Based on IPCC guidance, the CSNA now requires MDE to use the global warming potential of methane over a 20-year time horizon (of "GWP20") in accounting for fugitive methane emissions in the development of Maryland's inventory of GHG emissions. CSNA § 4 (codified at EN § 2-1205(e)(3)). MDE first incorporated this change in accounting in its recent update of the State's GHG inventory for 2020, having previously used a GWP over a 100-year time horizon ("GWP100") for evaluating methane. Overall, methane emissions are reported to account for roughly half of the currently observed net warming of 1.0°C above pre-industrial levels. EXEC. OFFICE OF THE PRESIDENT, DEP. OF SEC. OF STATE, *The Long-Term Strategy of the United States, Pathways to Net-Zero Greenhouse Gas Emissions by 2050* (Nov. 2021), at 3, 18, 37, https://www.whitehouse.gov/wp-content/uploads/2021/10/US-Long-Term-Strategy.pdf.

[59] GHG emissions resulting from the delivery and combustion at end-use (including residential, commercial, and industrial use) of fossil gas accounts for 11.54 percent of statewide gross GHG emissions, while emissions resulting from the upstream gas industry accounts for 5.14 percent of the State's gross emissions. MDE, *2020 Maryland GHG Inventory* (Sep. 24, 2022), https://mde.maryland.gov/programs/Air/ClimateChange/Pages/GreenhouseGasInventory.aspx.

[60] *See, e.g.*, CSNA §§ 10(a)(1)-(2).

reduction in GHG emissions from 2006 levels by 2020.[61] The General Assembly has since raised the targets for GHG emissions reductions, first modifying the law in 2016 to require a 40 percent reduction from 2006 statewide GHG emissions levels by 2030[62] and then, in the Climate Solutions Now Act of 2022 ("CSNA"), requiring a reduction of 60 percent from 2006 levels by 2031 and net zero GHG emissions by 2045.[63]

In support of these policy goals, the State established the Maryland Commission on Climate Change ("MCCC") "to advise the Governor and General Assembly on ways to mitigate the causes of, prepare for, and adapt to the consequences of climate change."[64] Informed by the findings of the IPCC, the MCCC issues annual recommendations to lawmakers about how to meet the State's GHG goals. In 2021, the MCCC released a technical report finding that "[r]esidential customers can save costs by electrifying all building end-uses compared to using gas."[65] Consistent with this analysis, the MCCC concluded in its *Building Energy Transition Plan* that building gas consumption "is expected to decrease between 62 and 96 percent by 2045" and made numerous recommendations in support of building electrification.[66] Significantly, the General Assembly in 2022 endorsed the MCCC's strategy, declaring itself "[i]n alignment with

[61] GGRA, 2009 Md. Laws Ch. 171, 172 (codified at former EN § 2-1204).
[62] GGRA – Reauthorization, 2016 Md. Laws Ch. 11 (codified at former EN § 2-1204.1).
[63] CSNA §§ 3-4 (codified at EN §§ 2-1201, 2-1204.1, 2-1204.2).
[64] EN § 2-1301(a). Two governors established the MCCC by executive order; and it has since been codified in statute. Md. Code Regs. 01.01.2007.07; Md. Code Regs. 01.01.2014.14; 2015 Md. Laws Ch. 429 (codified at EN §§ 2-1301, et seq.).
[65] *Md. Building Decarbonization Study* at 72.
[66] MCCC, *Building Energy Transition Plan: A Roadmap for Achieving Net-Zero Emissions in the Residential and Commercial Buildings Sector* (Nov. 2021), at 9, 19-23, https://mde.maryland.gov/programs/air/ClimateChange/MCCC/Documents/2021%20Annual%20Report%20Appendices%20FINAL.pdf.

the [MCCC's] recommendation to transition to an all-electric building code" and stating its support for "moving toward broader electrification of both existing buildings and new construction as a component of decarbonization."[67]

More recently, the MCCC's *2022 Annual Report* called for the General Assembly to mandate that the Commission issue "orders and regulations … for managing a transition to meet the GHG reduction goals of the [CSNA] that establishes requirements for gas utility planning for achieving a structured and just transition to a near-zero emissions buildings sector in Maryland."[68] The report further recommends that the gas companies, under the Commission's oversight, develop transition plans containing elements outlined in the recommendations.[69] Among these elements is the call for "appropriate gas system investments/abandonments for a shrinking customer base and reduction in gas throughput in the range of 60 to 100 percent by 2045."[70]

Separately, State law requires MDE to develop a statewide GHG reduction plan.[71] MDE's initial plan, issued in 2021 before the CSNA was enacted, identified strategies for achieving reductions across broad sectors of the Maryland economy (electricity generation, transportation, and buildings).[72] The plan promoted converting buildings to electricity by replacing the use of gas for space and hot water heating with more efficient

[67] CSNA § 10.
[68] *MCCC 2022 Annual Report* at 16-17.
[69] *Id.*
[70] *Id.*
[71] EN § 2-1205.
[72] *2030 GGRA Plan* at unnumbered introductory page ("The 2030 GGRA Plan sets forth a comprehensive set of measures to reduce and sequester GHGs, including investments in energy efficiency and clean and renewable energy solutions, clean transportation projects and widespread adoption of electric vehicles, and improved management of forests and farms to sequester more carbon in trees and soils.").

electric-powered technology.[73] In an update following enactment of the CSNA, MDE found that the new State goal to reduce statewide emissions by 60 percent by 2031 will require taking more aggressive measures, including further reductions of fossil fuel use in buildings.[74] MDE's updated report identifies as one of four priorities for immediate action: "Rapidly replace space heating and water heating equipment [fired with fossil fuels, including gas] with efficient electric heat pumps…."[75]

In sum, the General Assembly, the MCCC, and MDE all have identified building electrification as priority policy, recognizing its capacity to reduce emissions from fossil fuel use for space and water heating and to help Marylanders save more money on energy.[76] Their findings, recommendations, and declarations of policy conclusively establish electrification as a cost-effective compliance pathway for Maryland's State climate policy.

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[73] *Id.* at xvii ("A 100% clean electricity system will enable decarbonization and electrification of the transportation and building sectors, as EVs and electric heating systems use carbon-free energy sources."); *id.* at xix ("Combustion of fossil fuels in buildings is a substantial source of emissions in Maryland. Most of this energy is for space and water heating. The 2030 GGRA Plan reduces emissions from energy use in residential and commercial buildings by prioritizing energy efficiency… and by converting fossil fuel heating systems to efficient electric heat pumps that are powered by increasingly clean and renewable Maryland electricity."), *id.* at 47-48 ("[T]he 2030 GGRA Plan incorporates estimates of the emissions reductions from converting fossil fuel burning systems to efficient heat pumps that are powered by increasingly clean and renewable Maryland electricity.").
[74] MDE, *Reducing Greenhouse Gas Emissions in Maryland: A Progress Report* (Sept. 2022), https://mde.maryland.gov/programs/air/ClimateChange/Documents/GGRA%20PROGRESSS%20REPORT%202022.pdf.
[75] *MDE Progress Report* at 2.
[76] *See* CSNA §10(a)(1)-(2); *MCCC 2022 Annual Report* at 16-17*; MDE Progress Report* at 2.

2. Federal policy and local government policy make the need for Commission action even more urgent.

In addition to the State policy that the Commission must consider in weighing its duties to regulate in the public interest, the Commission should also take notice of federal and local government policies that will further drive electrification, discussed below.

i. Federal policy

Like the State, the federal government has proposed aggressive targets to reduce GHG emissions economy-wide. In 2021, President Biden announced a renewed national commitment to tackling climate change. Through Executive Order, the President committed to taking a whole-of-government approach to the issues, directing agencies "to immediately commence work to confront the climate crisis,"[77] and to "prioritize action on climate change in their policy-making and budget processes, in their contracting and procurement, and in their engagement with State, local, Tribal, and territorial governments; workers and communities; and leaders across all sectors of [the] economy."[78]

Federal climate policies have taken both a carrot and stick approach to reduce fossil gas use, providing for investments and incentives as well as regulation. The Environmental Protection Agency ("EPA") continues to exercise its authority to set and implement environmental standards,[79] the Department of Energy and Council on

[77] Exec. Order 13990, 86 Fed. Reg. 7037 (Jan. 20, 2021).
[78] Exec. Order 14008, 86 Fed. Reg. 7619 (Jan. 27, 2021).
[79] *See e.g.,* Climate Change Regulatory Actions and Initiatives, EPA, https://www.epa.gov/climate-change/climate-change-regulatory-actions-and-initiatives (last updated Dec. 19, 2022) (describing recent rulemakings to, among other things, strengthen emissions reduction requirements for oil and natural gas sources).

Environmental Quality recently announced efforts to electrifying federal buildings,[80] and Congress recently took unprecedented action to advance emissions reductions through large-scale investments in renewable technologies and tax credits for electrification technologies.[81]

While the Infrastructure Investment and Jobs Act (IIJA) provided for substantial spending on physical infrastructure to support electrification, the Inflation Reduction Act (IRA) contains hundreds of billions of dollars in spending and tax credits to encourage consumers to electrify and to incentivize companies to invest in these electric technologies. The IRA, for example, provides numerous credits and rebates for electric heating and cooling systems and certain electric appliances. These incentives will accelerate the market trend toward building electrification described above.

Together, these federal laws provide substantial potential for climate-focused investments that could ultimately help the nation reach its 2030 and 2050 goals by electrifying end-uses.[82]

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[80] U.S. Dep't of Energy, *Biden-Harris Administration Announces Steps to Electrify and Cut Emissions from Federal Buildings* (Dec. 7, 2022), https://www.energy.gov/articles/biden-harris-administration-announces-steps-electrify-and-cut-emissions-federal-buildings (announcing a new proposed rule requiring new or newly renovated federal buildings to reduce their on-site emissions associated with the energy consumption of the building by 90 percent relative to 2003 levels beginning in 2025, and to fully decarbonize their on-site emissions by 2030); Office of the Fed. Chief Sustainability Officer, Council on Env'tl Quality, *Building Performance Standard* (Dec. 7, 2022), https://www.sustainability.gov/federalbuildingstandard.html (announcing the first ever federal building performance standard, requiring agencies to cut energy use and electrify equipment and appliances to achieve zero scope 1 emissions in 30 percent of the building space owned by the Federal government by square footage by 2030).

[81] *See* Infrastructure Investment and Jobs Act, Pub. L. No. 117-58 (2021); Inflation Reduction Act of 2022, Pub. L. No. 117-169 (2022).

[82] Megan Mhajan et al., *Updated Inflation Reduction Act Modeling Using the Energy Policy Simulator*, ENERGY INNOVATION POLICY & TECH., LLC (Aug. 2022), https://energyinnovation.org/publication/updated-inflation-reduction-act-modeling-using-the-energy-policy-simulator/ (finding that provisions in the IRA could cut greenhouse gas (GHG) emissions 37 to 43

ii. Local policies

At the same time that the State and federal governments are enacting ambitious policies to reduce GHG emissions state and nation-wide, several local governments in Maryland have proposed their own electrification policies to reduce GHG emissions, in some cases more ambitiously. In 2021, Montgomery County enacted a strategic plan to cut community-wide GHG emissions 80 percent by 2027 and 100 percent by 2035, compared to 2005 levels.[83] The plan includes goals for 100 percent building electrification by 2035.[84] To this end, the County Council recently passed Building Energy Performance Standards legislation, which set minimum energy performance thresholds for existing commercial and multifamily buildings of 25,000 gross square feet or more.[85] Even more recently, the County Council passed a Comprehensive Building Decarbonization bill—the first of its kind in the State—which will ban new buildings from using gas, beginning in 2027.[86]

Other local jurisdictions are considering their own actions. In early 2022, Prince George's County released a draft *Climate Action Plan*, which includes a commitment "to

percent below 2005 levels by 2030); John Larsen et al., *A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act*, RHODIUM GRP. (Aug. 12, 2022), https://rhg.com/research/climate-clean-energy-inflation-reduction-act/ (finding that the IRA has the potential to drive GHG emissions down to 32-42 percent below 2005 levels by 2030).

[83] *Montgomery County Climate Action Plan: Building a Healthy, Equitable, Resilient Community* (June 2021), https://www.montgomerycountymd.gov/climate/.

[84] *Id.* at xxi.

[85] Environmental Sustainability - Building Energy Use Benchmarking and Performance Standards, Bill 16-21 (Montgomery Cnty. Council, 2022)

[86] Buildings – Comprehensive Building Decarbonization, Bill 13-2022 (Montgomery Cnty. Council, 2022). The bill includes exemptions for certain buildings that need emergency backup systems such as hospitals, wastewater treatment plants, crematories, or high-energy industrial or commercial cooking facilities. It also exempts "major renovations and additions" from the requirements.

undertake a community-wide, just and equitable transition away from fossil fuels and toward renewable sources of energy" and to reduce GHG emissions by 50 percent by 2030, compared with 2005 levels, with the ultimate goal of achieving carbon neutrality by 2050.[87] Howard County[88] and Baltimore City[89] are also in the process of updating their climate action plans to account for new GHG emissions reduction goals.

As national policies push reform from the top down, ambitious county-level policies are pushing from the bottom up, impacting the building sector's heating systems and use of fossil fuels, all further heightening the need for long-term planning for utility infrastructure systems. On the other hand, just as states need to act quickly and decisively to take advantage of national-level policies like the IIJA and the IRA, these local government efforts can be enhanced or frustrated, depending on whether state regulation supports such efforts. The current absence of Commission action requiring comprehensive gas company planning undermines these efforts of local Maryland governments.

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[87] Prince George's Cnty. Climate Action Comm'n, *Draft Climate Action Plan* (Jan. 15, 2022), https://pgccouncil.us/DocumentCenter/View/7349/Draft-Climate-Action-Plan, at iii, 4.

[88] Howard Cnty. Office of Cmty. Sustainability, *Howard County Climate Forward: Climate Action and Resiliency Plan* (Preliminary Report 2022), https://livegreenhoward.com/wp-content/uploads/2022/12/HoCo-Climate-Forward.pdf (accounting for Howard County's new goals to achieve a 60 percent reduction in GHG emissions over 2005 levels by 2030 and net zero emissions by 2045).

[89] Balt. Office of Sustainability, *Climate Action Plan*, https://www.baltimoresustainability.org/plans/climate-action-plan/ (last accessed Jan. 18, 2023) (accounting for the City's new targets to achieve a 30 percent reduction in carbon emissions by 2025, a 60 percent reduction by 2030, and full carbon neutrality – or 100 percent reduction in net emissions by 2045 (relative to 2007)).

III. The Commission should act now because the gas companies' planning, practices, and operations are misaligned with economic reality, government policy, and the interests of residential utility customers.

Basic economics—combined with basic ratemaking principles—explain how electrification will cause customers to migrate away from gas use, with enormous impacts on gas companies and their remaining customers. The traditional ratemaking model allows utilities to invest in and earn a return on assets such as gas mains and service lines. Utilities recover and earn a return on their investment, typically over the asset's useful lifetime, by including the costs of their investments and the returns on them in the rates charged to customers. This traditional utility business model is designed to ensure that utilities can attract shareholders who will put up the money for the investments in exchange for a fair return of—and on—their investments. The business model presumes that without such investments, utilities would not be able to ensure reliability or meet customers' needs. This model works reasonably well when sales increase over time, but it leads to higher rates when sales are decreasing. And, as building electrification takes effect, gas utility sales *will* decrease.[90]

The gas companies are substantial, capital-intensive businesses, with operating assets that have long-lived physical functionality. They necessarily must plan, over long horizons, to properly construct, operate, and maintain this infrastructure. While current gas rate and planning arrangements, as supervised and regulated by the Commission, reflect the long-term nature of gas company business, these arrangements conflict with

[90] *See Synapse Report* at 13, Fig. 4.

technological advances that favor electrification, the State's climate policies, and the downsizing of the gas system that those policies necessarily entail.

The need for the Commission to mandate and oversee gas utility transition planning is urgent. Customer investments in buildings and company investments in delivery systems and supply commitments require advance planning. Both sets of investments are long-term; decisions that customers and gas companies are making now have ramifications for many years to come. Customer investments in appliances may last 20 years and, for new buildings, even longer. Utility rates are set based on the expectation that customers will pay for many gas utility investments over 40 years and sometimes over as long as 70 years. To induce the required changes in gas company plans and customer choices, it is imperative that the Commission send accurate investment signals—consistent with advances in technology and the State's climate change policies—to effectively reform the gas companies' businesses and the State's economy.

In this part of the petition, OPC describes: (1) how the gas companies' capital spending programs are inconsistent with the projected large reductions in gas consumption; (2) how these misaligned capital spending practices put customers at risk of significant price increases; and (3) how other gas company practices, aside from capital spending, are also inconsistent with customer interests.

A. Maryland gas companies' capital spending programs are inconsistent with the projected large reductions in gas consumption.

The State's targets to reduce GHG emissions by 60 percent from 2006 levels by 2031 and to achieve net zero emissions by 2045 will require significant change to the business models of the gas companies regulated by the Commission, and, therefore, require significant changes to the Commission's regulatory approach. Those changes must both grapple with decreasing consumption of gas and accommodate the long time it takes to roll over relatively inflexible capital investment in Maryland's building stock as electricity replaces fossil-based heating systems and appliances.

At present, the gas companies are spending on an accelerated basis to replace legacy infrastructure with new infrastructure that has a lifetime of 40 years or more, seeking to expand business for new customers and capacity. Their business-as-usual approach to planning and spending is based on historic levels of sales growth that are no longer realistic. Given the long-term consequences of *today's* decisions and *today's* investments, the current business models of the gas companies do not reflect the market realities of the coming declines in gas consumption and implementation of the State's climate change response strategies. As documented in detail in OPC's recent report, *Maryland Gas Utility Spending: Projections and Analysis*, the State's largest gas utilities are in the process of spending tens of billions of dollars on capital investments over the coming decades, with customers ultimately paying $125 billion by the end of the century, largely for investments gas utilities plan to make in the next ten to 20 years.[91] Further, the gas companies are spending tens of millions annually to add new gas customers and to

[91] DHInfrastructure, *Maryland Gas Utility Spending: Projections and Analysis* (Oct. 2022), at 23, 26, https://opc.maryland.gov/Gas-Utility-Spending-Report (attached as Appendix E).

expand the gas system.[92] In 2022 alone, BGE spent $78 million and Washington Gas more than $50 million on new customer acquisition and system expansion.[93]

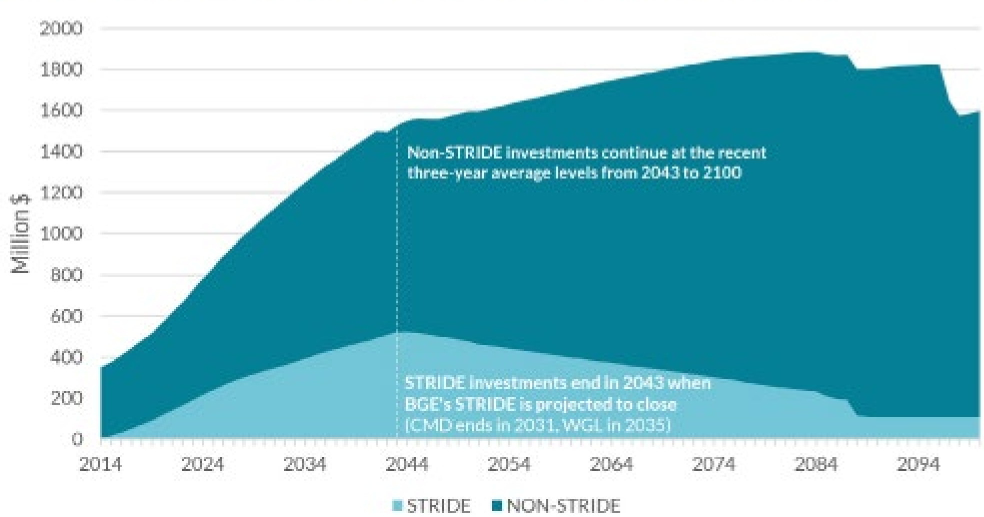
The gas companies have no plans to slow this accelerated pace of capital spending to add new infrastructure and reconstruct their legacy systems. BGE, for example, plans to continue Operation Pipeline—its program to replace its entire gas infrastructure, as it existed in 2013—until 2043, at a cost of more than $4 billion.[94] Operation Pipeline's costs will not be fully recovered until the end of the century, by which time customers would pay three to four times more than the initial costs after accounting for the utility's return.[95] These plans clearly serve the interests of the major gas companies' utility holding companies, which earn their profits from spending on capital infrastructure. Indeed, Exelon recently told its investors that BGE will increase its annual gas distribution capital spending to $500 million per year in 2024 and 2025, up from $475 million per year in 2022 and 2023.[96] However, that planned spending is not consistent with the public interest.

The long-term consequences of this spending are significant, given that these costs are recovered slowly, over many decades, just as gas consumption is declining. In fact, while Maryland's three largest gas utilities collectively are about one-third of the way through replacing their legacy systems built up over nearly a hundred years, they have

[92] *Gas Spending Report* at 35-37.
[93] *Id.*
[94] *Id.* at 11, Table 2.2.
[95] *Id.* at 3.
[96] Exelon, *Fall and Winter 2022 Investor Meetings* at 26, https://investors.exeloncorp.com/static-files/98091533-da5b-40c8-bef7-5abfacc0d2d0.

recovered only about 3 percent of the replacement costs.[97] The *Maryland Gas Spending Report* shows that the gas companies' current spending programs, if carried forward without adjustment, will lead to a cumulative capital investment of some $13 billion by 2043, with approximately a third incurred under the Strategic Infrastructure Development and Enhancement (STRIDE) pipe replacement program.[98] Moreover, the *annual* revenue requirement of this investment charged to the gas companies' customers rises to $1.5 billion by 2043 (including both STRIDE and non-STRIDE investments), assuming the use of current depreciation rates.[99] These revenue requirements are depicted in the following figure from the report:

Figure 1.2: Combined Three-Company STRIDE and Non-STRIDE CAPEX Annual Revenue Requirement



[97] *Gas Spending Report* at 32.
[98] PUA § 4-210; *Gas Spending Report* at 2, Table 1.2 ($4.76 billion in STRIDE capital expenditures + $8.29 billion in non-STRIDE capital expenditures). BGE recently informed the Commission that it will propose to complete its STRIDE replacement program through its multi-year rate plan. *Baltimore Gas and Electric Co. 2023 STRIDE Project List and Factor Filing*, Case No. 9468, Maillog No. 242893 (Nov. 1, 2023).
[99] *Gas Spending Report* at 4.

As the figure shows, 97 percent of STRIDE replacement costs will be recovered in *future* years—when gas consumption must decline significantly for Maryland to meet its GHG reduction targets. And STRIDE replacement costs (the light blue portion of the graph) are less than half of the ongoing gas utility capital spending.

These investments must be assessed in light of the projected large reductions in gas sales. Those sales reductions raise the critical question of how—and if—the gas companies will recover the costs of these ongoing investments in infrastructure while maintaining their core obligations to provide safe and reliable service to remaining customers.

B. The gas companies' misaligned capital spending practices put customers at risk of significant price increases.

As a result of market forces and government policies driving electrification, fewer utility customers will be buying less gas to pay for these massive investments. To recover both the return of and on those investments, gas utilities will have to increase distribution rates. In turn, higher gas rates are likely to spur more customers to electrify their gas end-uses (furnaces and appliances), leaving even fewer customers on the system to pay for the massive investments. As this process goes on, those with the means to electrify—*i.e.*, those who can afford the upfront costs of changing their gas appliances to electric ones and can modify their buildings to accommodate the switch—will be the fastest to do so.[100] Without changes to regulatory practices or direct assistance, those without access to capital (*e.g.*, low- and moderate-income customers) or the ability to make changes to their

[100] *See, e.g.*, *Synapse Report* at 4; *BGE Strategy* at 35.

dwellings (*e.g.*, renters) will be the customers left behind on an increasingly costly gas system. Rate escalation will hit these groups the hardest, even though they are least able to afford higher utility bills.

The ramifications of continuing business-as-usual are profound. The *Maryland Gas Spending Report* showed huge increases in gas utility annual revenue requirements as a result of current capital spending on existing and new infrastructure. Using conservative assumptions, the report finds that BGE's annual revenue requirement will peak at $1.532 billion in 2084, an amount that is 2.3 times 2023 levels.[101] While 2084 may seem distant, the investments BGE intends to make over the next 10-20 years underlies that record-setting 2084 rate base.

Meanwhile, long before 2084—that is, by 2045—gas sales are projected to decline by at least 60 percent, even using the most conservative assumptions.[102] Yet it is through those declining gas sales that the gas companies will recover their increasing revenue requirements resulting from their investments on the delivery system. Delivery rates are based on gas usage, and as recovery of those fixed costs fall to an ever-shrinking base of customers and sales, massive increases in rates will be necessary. The report prepared for OPC by Synapse, *Climate Policy for Maryland's Gas Utilities: Financial Implications* (the "*Synapse Report*") projected this upwards trajectory of gas rates in the residential sector as Marylanders switch from fossil-fuel fired building furnaces and appliances to electricity in conformity with the State's GHG reduction targets. Synapse modeled the

[101] *Gas Spending Report* at 24.
[102] *BGE Strategy* at 25; *MCC Transition Plan* at 10.

impact on rate base, revenues, and expenses for each of the three major Maryland gas companies. For each utility, Synapse modeled the increases in the delivery rates as well as the residential customer rate impact of using alternative gaseous fuels to offset increasing portions of the gas distribution system's emissions.

Synapse's modelling projects devastating customer impacts in both the high- and low-cost scenario for the price of non-fossil fuels (alternative gaseous fuels, or AGF). The report assumed that new construction is all-electric by the late 2020s and that, for existing buildings, electrification is achieved through steady increases in heat pumps' share of the Maryland market based on recent trends documented in U.S. Census data. Under Synapse's model, heat pumps replace fossil fuel furnaces at the end of the furnaces' useful life, such that by 2030, over 95 percent of households replacing space heating equipment are buying heat pumps, increasing to 100 percent by 2035.[103] The cost impacts for remaining gas customers are as follows: [104]

[103] *Synapse Report* at 11-12.
[104] Figures 16 through 18 are from the *Synapse Report* at 20.

Figure 16. BGE residential building total gas costs (Low and High AGF Price)

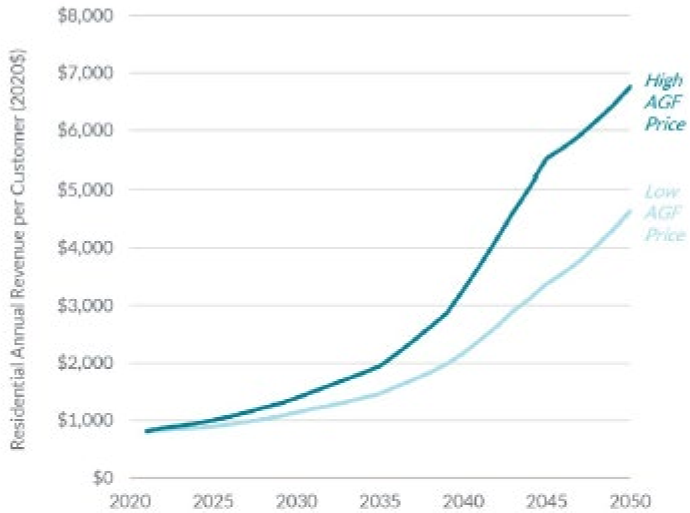


Figure 17. WGL residential building total gas costs (Low and High AGF Price)

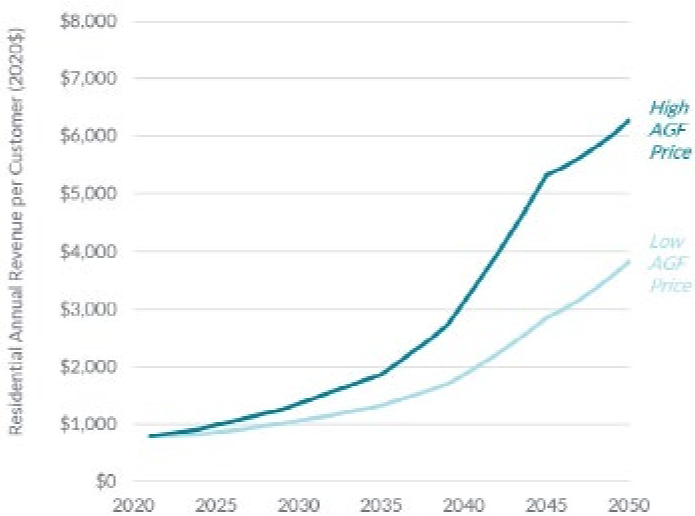


Figure 18. Columbia residential building total gas costs (Low and High AGF Price)

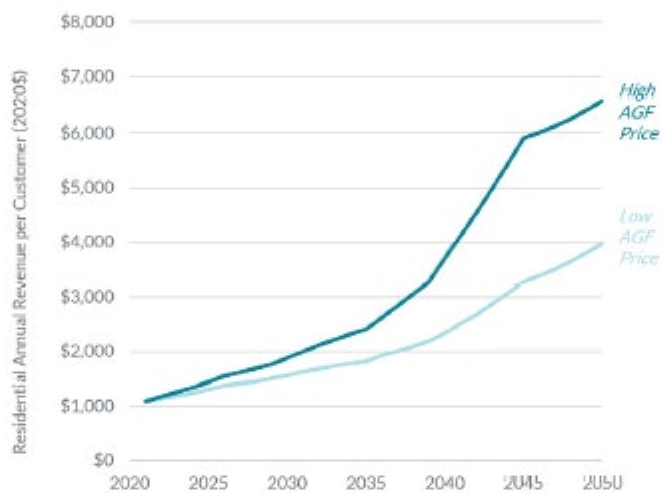


Figure 16 illustrates that with increasingly larger annual bills, customers remaining with BGE for gas service in 2050 could see rate increases of up to *ten times* today's rates. The study projects BGE average customers who paid $820 for gas service in 2021 will pay as much as $1,994 in 2035 and $6,759 in 2050.[105] Figures 17 and 18 show that other gas utilities will also need substantial rate increases as well. Notably, these rate increases will be avoided by those with the means to leave the gas system through electrification. Low-income customers and those that cannot control their energy source, like renters, will be most adversely affected.

As the *Synapse Report* explains, electrification will happen gradually as the building stock turns over. Gas rate increases due to electrification will also be gradual. But at some point, it will no longer be possible for the gas utilities to raise rates to the

[105] *Id.*

levels necessary for recovering their fixed rate base costs while remaining economically viable. As customer departures increase and rates rise to unaffordable levels, gas utilities are likely to have substantial unrecovered and uneconomic assets remaining in rate base and on their books.[106]

The potential for stranded costs is not unique to Maryland; a Brattle Group analysis found that declining costs for electrification in conjunction with policy initiatives could lead to approximately $150-180 billion in unrecovered gas distribution infrastructure across the United States.[107] Comprehensive planning, however, can help lessen the probability or amount of stranded costs and mitigate the hardship of increasing rates on customers. Further, comprehensive planning and transparent regulatory policies can help insulate customers from stranded cost exposure by assigning the risks of speculative investments to those who will reap any benefit and can mitigate those risks—the gas companies themselves, rather than their captive customers.

C. Other gas company practices are inconsistent with customer interests, do not require significant investigation, and are ripe for priority action.

This petition requests that contemporaneously with the investigation into capital expenditures and long-term planning in the Transition Track, the Commission open a Priority Track to address—on an expedited basis—at least four utility practices that are plainly contrary to the public interest and the interests of customers and are ripe for action now. Action by the Commission concerning these practices would constitute

[106] *Id.* at 21.
[107] Brattle Grp. at 11.

"no-regrets" actions in that they would not prejudice or otherwise affect the outcome of the investigation and rulemaking concerning long-term transition planning. At least four areas of priority measures are already identifiable today: (a) gas commodity procurement practices; (b) gas line-extension policies; (c) gas marketing practices; and (d) EmPOWER Maryland gas appliance programs. We briefly touch on these four, while urging the Commission to seek stakeholder input to identify additional priority areas and allow for a period of discovery on the issues raised.

1. Procurement practices

The gas companies' current procurement practices for gas supply and pipeline capacity are documented in filings made with the Commission each year. Companies file annual capacity plans, extending for a five-year forward period.[108] Through these plans, the gas companies disclose their long-term commitments for gas pipeline capacity to meet demand annually and during colder periods. Gas supply procurements are reviewed during annual evidentiary hearings, pursuant to PUA § 4-402(d). The gas companies appear to determine how much gas supply and pipeline capacity to procure by using econometric analysis to estimate how customer growth, weather, and other drivers have impacted demand historically, then projecting values for those drivers going forward to forecast demand in the future.

[108] *Baltimore Gas and Electric Company Gas Capacity Plan, Winters 2022/2023 through 2026/2027*, Maillog No. 242865 (Oct. 31, 2022); *Washington Gas Light Company Energy Acquisition 2023-2027 Portfolio Plan*, Maillog No. 300182 (November 15, 2022); *Columbia Gas of Maryland, Inc., Strategic Gas Supply Plan 2023-2027*, Maillog No. 242655 (Oct. 14, 2022).

Writ large, such “capacity planning” is complex and warrants consideration by the Commission in the long-term transition track of the proposed proceeding.[109] However, because the Commission requires the gas companies to update their gas supply filings annually, and because gas companies likewise enter into gas supply contracts every year, the Commission should include an examination of the companies’ current procurement practices in the near-term priority track of the proceeding.

Currently, as with their current capital investment programs, the gas companies’ gas procurement practices fail to plan sufficiently for the reductions in gas demand attendant on decarbonization. Although at least one gas company has pledged to “adjust [its] natural gas procurement strategy to align with” the goals in the CSNA “when appropriate,”[110] all of the gas companies continue to commit to long-term contracts based on models that assume steady or growing gas consumption, as though Maryland’s State policy to reduce gas consumption did not exist. The Commission should immediately require the gas companies to align their procurement strategies with the CSNA and the reality that gas sales will drop over time.

2. Gas line-extension policy

Current utility line-extension policies expose ratepayers to risks of stranded gas infrastructure costs caused by system expansion. Washington Gas’s line-extension policy provides an example. Whether Washington Gas’s existing customers pay for the company to extend its distribution facilities to serve a new location or whether the

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[109] *See* Appendix A.
[110] *BGE Gas Capacity Plan* at 6.

proposed customer is required to pay depends on whether the anticipated future revenues from the extension are sufficient to cover the extension's cost.[111] If the projected revenues are not realized, existing customers wind up compensating the utility for the unrecovered cost of extending its service to the new customer.

The problem is that Washington Gas's current test assumes a life cycle for line extension of 30 years.[112] In the past, it may have been reasonable to assume that added customers would remain on the system for 30 years. Now, however, the technological, market, and policy trends described in this petition cast doubt upon the future of gas as an energy source in the State 30 years into the future. Revenue projections that assume steady gas system growth exacerbate the risks of stranded infrastructure costs by adding projects to the gas system that may not be economic in the long term. Current line extension policies do not protect customers from the risks of such uncertainty.

3. Gas company marketing practices

If the State is to achieve its climate goals, the Commission must change its regulatory policies that permit gas companies to promote the purchase and use of fossil gas in homes. These messages encourage customers to make investment decisions that are detrimental to their long-term interests. They fail to consider, for example, that purchasing a gas furnace today will likely result in higher lifetime costs than if the customer has purchased an electric heat pump. The data are clear that rates for gas utility

[111] *Washington Gas Light Company Maryland Rate Schedules and General Service Provisions for Gas Service*, P.S.C. Md. No. 6, G.S.P. 13-14, at 67-69 (Nov. 22, 2011).
[112] *Id.* at G.S.P. 14(e), at 69A (Oct. 14, 2022).

service are increasing—both for distribution and commodity costs. And they will continue to increase as gas companies continue to spend on new and replacement infrastructure and as the building sector moves—even incrementally—to electrify. Put simply, it is contrary to customer interests to buy gas equipment that has a service life extending ten years or even longer.

An example is Washington Gas's marketing campaign describing gas as "a clean energy" that is less emissions-intensive and more environmentally beneficial than an all-electric home.[113] Washington Gas's promotional materials failed to disclose the well-established fact that fossil gas production, distribution, and consumption are major sources of greenhouse gas emissions. Yet, the Commission's order allowing Washington Gas's marketing message effectively allows gas utilities to engage in such forms of "green marketing." This petition would facilitate the broader inquiry about gas utility marketing practices that the Commission indicated was appropriate when it dismissed OPC's complaint alleging that Washington Gas's marketing violated the public interest standard of PUA § 2-113.[114]

4. EmPOWER Maryland programs

Current gas utility EmPOWER programs are misaligned with customers' interests and State climate policy in two readily identifiable ways. First, they incentivize consumer purchases of gas appliances. Such incentives are contrary to the long-term interests of

[113] *See* OPC Comp., Case No. 9673 (Nov. 23, 2021).
[114] Order No. 90057, Case No. 9673 (Feb. 7, 2022), at 6, ¶ 18 (finding that "a complaint against one utility is an inappropriate forum to address the broader issues raised by natural gas and its role in greenhouse gas emissions").

residential customers and State policy. Ending incentives for household gas appliances is required to conform Commission policy with the public interest, in particular long-term customer interests in minimizing their energy bills. As explained above, it is contrary to customer interests to buy gas equipment that has a service life extending ten years or even longer. In its 2021 and 2022 recommendations, the MCCC also called for ending fossil fuel appliance incentives.[115]

Second, EmPOWER is not being used to incentivize fuel switching to electric heat pumps. Ending incentives for gas appliances and using the funding to incentivize electric heat pump purchases instead will bring about several benefits. These actions will: (1) help insulate ratepayers from rising gas delivery rates in both the short and long term, (2) prioritize the adoption of electric heat pumps, consistent with the General Assembly's support of "moving toward broader electrification of both existing buildings and new construction as a component of decarbonization,"[116] and (3) lead to net-reduced GHG emissions statewide. In its past three annual reports, the MCCC has recommended that EmPOWER encourage fuel switching.[117]

Notably, small levels of participation in programs incentivizing electric heat pumps will provide more GHG reductions than continued funding of gas appliance incentives. A May 2022 analysis of Washington Gas Light's gas equipment programs found that more reductions in GHG emissions would occur if just one in five participants

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[115] *MCCC 2022 Annual Report* at 16 (citing a similar recommendation from 2021).
[116] CSNA §§ 10(a)(1)-(2).
[117] *MCCC 2022 Annual Report* at 16 (citing similar recommendations from 2020 and 2021).

in the existing gas equipment program chose an electric heat pump instead of a gas furnace, even if the other four consumers chose a less efficient gas furnace in the absence of gas incentives.[118] OPC's analysis of the GHG Abatement Potential Study confirmed a similar finding: "the utilities and DHCD can achieve greater GHG reductions by promoting and installing electrification measures instead of gas appliances—even if some customers install less efficient gas equipment as a result."[119] Thus, ending EmPOWER gas appliance incentives is a "no-regrets" policy that the Commission should not delay in implementing.

IV. A comprehensive and proactive planning proceeding is necessary to ensure that the rates, service, and operations of Maryland's gas companies are consistent with the public interest, not just the gas companies' private interests.

The Maryland Supreme Court has observed, that with respect to public utilities, "the public good [is] best served by not only permitting, but assuring, a monopolistic structure, coupled with *extensive government control* over the rates, service, and operations of such a structure."[120] In statutory terms, the Commission is charged with exercising "extensive government control" through its duty to "supervise and regulate" public utilities to ensure that they operate in the public interest.[121]

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[118] *Office of People's Counsel Response in Support of Maryland Energy Efficiency Advocate's Motion to End Gas Appliance Incentives*, Case No. 9648, Maillog No. 240629 (May 10, 2022), at 2, Appendix 1.
[119] *Office of People's Counsel's Comments on EmPOWER Goals for the 2024-2026 Program Cycle, Case No. 9648, Maillog No.* 301064 (January 27, 2023), at 4.
[120] *Delmarva Power & Light Co. v. Pub. Serv. Comm'n*, 370 Md. 1, 6 (2002) (emphasis added).
[121] PUA § 2-113.

The Commission's role as "the representative of the public interest … does not permit it to act as an umpire blandly calling balls and strikes for adversaries appearing before it[. Rather,] the right of the public must receive active and affirmative protection at the hands of the [regulator]."[122] In other words, the Commission cannot fulfill its statutory obligation by merely reacting to utility proposals; rather it must, instead, articulate an affirmative vision of the public interest and take the initiative to ensure that utilities meet it. Among other things, that means directing gas companies to plan for substantially declining sales.

The gas companies themselves recognize that major changes to their industry are coming and that those changes demand comprehensive gas planning.[123] But without the Commission's "active and affirmative" oversight, company plans will be influenced by the incentive structure that rewards the companies' private interest in profit-making based on investments in capital, which can result in serious misalignments with the public interest.[124]

Moreover, because the impending challenges facing the gas companies and their customers are industry-wide, and not specific to individual gas companies, they must be dealt with in the comprehensive, proactive, and Commission-driven proceeding that this petition proposes, rather than in a piecemeal, reactive, and utility-driven proceeding such

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[122] *Scenic Hudson Pres. Conference et al. v. Fed. Power Comm'n*, 354 F.2d 608, 620 (2d Cir. 1965).
[123] *See* Part IV.A below.
[124] A central consequence of rate of return regulation is the incentive it gives regulated utilities to make capital investments, inconsistent with and in excess of the most efficient, least cost level. This phenomenon is often called the Averch-Johnson effect after a seminal article describing the concept authored by the term's namesakes. Harvey Averch & Leland Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052 (1962).

as an individual rate case. The Commission exists to provide effective regulatory oversight of these companies so that they perform in the public interest. A planning process that defers to the gas companies, in which the Commission plays a passive role, undermines the Commission's function and seriously threatens the public interest.

Part IV.A of this section explains how the statements and actions of the gas companies demonstrate support for the long-term planning called for by this petition. Parts IV.B and IV.C show, through two examples, why the public interest demands that the Commission address long-term gas company planning in a statewide proceeding, rather than allow the gas companies to lead the planning process through rate cases. Specifically, Part IV.B addresses the problems with the gas companies' reliance on low or zero-carbon fuels as a solution, while Part IV.C addresses fundamental flaws in BGE's recent *Integrated Decarbonization Strategy*.

A. Statements and actions of the Maryland gas companies support the need for comprehensive gas planning.

The gas companies' statements and actions support the need for comprehensive gas planning consistent with this petition. Exelon, BGE's parent, for example, participated in a recent roundtable discussion that National Grid and RMI convened "to explore what it may take to decarbonize the gas distribution system in the US and the customer end uses it serves today."[125] The roundtable discussions culminated in a report that recommends, among other matters: "urgent action by all parties, but especially from

[125] Nat'l Grid & RMI, *Collaborating for Gas Utility Decarbonization* (Oct. 2022), at 2, https://www.raponline.org/wp-content/uploads/2022/11/rap-rmi-natgrid-collaborating-gas-utility-decarbonization-2022-october.pdf.

policymakers and regulators, to enable near-term emissions reductions and guide utility investment and decision-making toward economy-wide decarbonization by 2050."[126] The report's policy recommendations expressly advise "utilities and regulators [to] conduct gas infrastructure planning as part of comprehensive equitable integrated energy system planning at the state or regional level."[127] More specifically, the report calls for "an inclusive, comprehensive, and iterative long-term planning process at the state level," the result of which "should then guide the development of utility-specific plans."[128]

BGE's recently published *Integrated Decarbonization Strategy* ("*BGE Strategy*") also supports the Commission's commencement of the proceeding this petition requests. BGE and its consultant E3 emphasize in the report that "*regulatory and policy support will be necessary* to both *manage* the challenges associated with decarbonization and capture new opportunities."[129] The language of "manage" and "regulatory and policy support" is planning language.

Washington Gas has similarly recognized the need to adapt its business practices to align with emissions reduction targets. In 2020, Washington Gas engaged the consulting firm ICF to conduct a study of alternative approaches to emissions reductions to align with the District of Columbia's legislated commitments to reduce GHG emissions by 60 percent by 2030 (relative to 2006 levels) and achieve carbon neutrality

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[126] *Id.* at 3.
[127] *Id.* at 5.
[128] *Id.*
[129] *BGE Strategy* at 42 (emphasis added); *see also id.* at 7, 46.

by 2045.[130] Like the *BGE Strategy*, Washington Gas's resulting report highlights the complexity of the issues and the need for regulatory oversight. It further offers a glimpse into the implications of a failure to act, finding that Washington Gas faces billions of dollars in potential stranded costs from high levels of electrification.[131] The Commission should take the cues from the BGE and Washington Gas studies and open proceedings to manage the gas transition so that it occurs consistent with customers' and the public's interest, including mitigating stranded costs.

B. Alternative low or zero carbon fuels are not a viable large-scale substitute for fossil gas.

The *BGE Strategy* advances what has become a common gas company narrative: that decarbonization of the gas companies' operations in line with Maryland's climate change policies can be achieved by depending heavily on the large-scale replacement of conventional gas with renewable natural gas ("RNG"), green hydrogen, or various types of synthetic gas.[132] This narrative is seriously flawed. As explained in the *Synapse Report*, multiple recent studies regarding the availability and cost of RNG—including studies by industry consultants—have concluded that it is not available at anywhere near the scale required to meet current demand and can only be procured at significantly higher costs.[133] Significant cost, availability, and technical compatibility issues also exist

[130] Climate Commitment Act of 2022, 69 D.C. Reg. 009919 (Sept. 21, 2022) (codified at D.C. Code § 8-151.09d); ICF Resources, LLC, *Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals* (Apr. 2020).
[131] *ICF DC Report* at 27.
[132] *BGE Strategy* at 4-5, 8-9.
[133] *See, e.g.,* ICF prepared for Michigan Pub. Serv. Comm'n, *Michigan Renewable Natural Gas Study, Final Report* (Sept. 23, 2022), at 4-6 (Michigan assessment of RNG potential: achievable – 57 tBtu/yr., feasible – 148 tBtu/yr., inventory – 313 tBtu/yr.; current Michigan gas consumption across all sectors

with blending hydrogen with methane in the gas companies' existing gas distribution network to allow utilization of the existing gas delivery network and end-use gas appliances.[134] While there may be a need for low-emissions hydrogen and other alternative fuels to power certain end-uses that are far more expensive to electrify or for which there are no available electric alternatives (such as heavy industry and heavy-duty transportation), none of the alternatives that would reduce GHG emissions are available at scale to replace fossil gas across-the-board.[135] Any reliance on the projected future use of alternative gaseous fuels to justify maintaining business-as-usual investment in gas infrastructure is speculative at best and serves to promote the gas companies' interests in

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average of 673 tBtu/yr. 2016-2020, costs ranging from $9.92-49.17/MMBtu); ICF prepared for NYSERDA, *Potential of Renewable Natural Gas in New York State*: *Final Report, No. 21-34* (Apr. 2022), at ES-1-2 (New York assessment of RNG potential estimated at between 47 tBtu/yr. and 147 tBtu/yr. (2040) with estimated average weighted costs between $11.29/MMBtu and $34.56/MMBtu; vs. natural gas consumption across all sectors in New York of 1,280 tBtu in 2017); ICF prepared for Am. Gas Found., *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment* (Dec. 2019), at 2,5 (US national assessment - low scenario of 1,660 tBtu/yr. (by 2040), high scenario 3,780 tBtu/yr. (2040) vs. 10 year average residential only gas consumption of 4,846 tBtu/yr. (2009-2018); cost of production estimated to range from $7 to $45/MMBtu); *see also Synapse Report*, Part 3.3, at 7-8.

[134] *See, e.g.*, Jochen Bard et al., *The Limitations of Hydrogen Blending in the European Gas Grid*, FRAUNHOFER INST. FOR ENERGY ECON. AND ENERGY SYS. TECH. (Jan. 2022) (identifying severe technical upper limits to the blending of hydrogen depending on type of network equipment and component materials); Int'l Renewable Energy Agency ("IRENA"), *Global Hydrogen Trade to Meet the 1.5 ^{o}C Climate Goal: Part II, Technology Review of Hydrogen Carriers* (2022), at 103 (identifying a higher risk of pipe metal embrittlement and decreases in the energy content of a given volume of hydrogen compared to methane); *id.* at 101 (identifying that the hydrogen blending option "faces multiple challenges. The CO_2 benefit is small, equivalent to about a third of the blending fraction (i.e., a blending target of 20 percent by volume only leads to about 7 percent lower CO_2 emissions). It increases the gas price, as relatively cheap hydrogen of USD_3/kgH_2 is about 10 times the typical natural gas price in the US [assumed to be 2.5 USD/MMBtu]."); Jan Rosenow, *Is Heating Homes with Hydrogen All but a Pipe Dream? An Evidence Review* (2022), http://www.janrosenow.com/uploads/4/7/1/2/4712328/is_heating_homes_with_hydrogen_all_but_a_pipe_dream_final.pdf (assessing multiple studies showing that cost and technical issues with hydrogen preclude significant deployment for supply of residential heating); Cal. Pub. Util. Comm'n, *Final Report, Hydrogen Blending Impacts Study*, Case No. R1302008 (Jul. 18, 2022) (arriving at similar conclusions regarding severe technical limits to hydrogen blending with methane above 5 percent by volume in the existing gas distribution network)*;see also Synapse Report* at 8-9.

[135] *Synapse Report* at 10.

maintaining and expanding the infrastructure over the public's interest in transitioning to more reliable sources of energy.

C. Other flaws in the *BGE Strategy* further highlight the need for a Commission-driven, long-term planning process.

In the *BGE Strategy*, the company's consultant, E3, describes three alternative scenarios for the evolution of the company's gas business over the period 2020-2045 to address the challenges of climate change and to enable the State to achieve its goals of net zero GHG emissions.[136] In each of the three scenarios, the company proposes a radical change in its business operating model, based on analysis that assumes high levels of electrification and the introduction of alternative low or zero carbon fuels—such as "renewable natural gas" ("RNG"), other low carbon fuel mixes (e.g., synthetic natural gas or biomethane), or hydrogen—into its facilities for delivery to customers in varying amounts. However, in all of the scenarios modelled, BGE projects a very significant decrease in the amount of gas delivered through its pipelines—from 60 to 78 percent.[137] This drastic reduction in throughput is a fundamental driver of the need for the comprehensive planning proceeding sought by this petition.

Although it contains important acknowledgments that "[e]lectrification is the primary driver of decarbonization,"[138] that the number of gas customers and overall throughput will decline under any scenario that achieves the State's emissions reduction

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[136] *BGE Strategy* at 16-17.
[137] *Id.* at 25.
[138] *Id.* at 37; *see also id.* at 25 ("Electrification is a key driver of decarbonization across all three scenarios considered."); *id.* at 5 ("Electrification is the core engine of decarbonization across all scenarios considered."); *id.* at 44 (same).

targets,[139] and that regulatory support will be necessary to manage the transition,[140] the *BGE Strategy* is flawed in numerous respects, reflecting BGE's own private interests and rendering its recommendations and conclusions fatally infirm for the public interest.

First, the strategy rests on several false premises. Even though each of its scenarios anticipates drastic reductions in gas throughput (at least 60 percent), none of the scenarios foresees any reduction in BGE's capital spending on its gas system. In fact, BGE directed its consultant to arrive at decarbonization strategies that depend on BGE maintaining both its electric and gas systems as they exist today, implicitly also maintaining its current plans to replace its gas system under its current capital investment program.[141] Thus, no pathway reflects any significant avoided gas infrastructure spending. As noted above, BGE plans to spend tens of billions of dollars, substantial portions of which potentially can be avoided with electrification. Fundamentally, BGE's plan illustrates the utility incentive—common to all Maryland gas companies—to spend on capital. It elevates Exelon's economic incentives and interest in maintaining two capital intensive infrastructures—one for gas and one for electricity—over the public interest.

Moreover, to support its findings, the study relies on the false premise that its "Integrated Energy System Scenarios" (meaning those that "rely on a combination of

[139] *Id.* at 25.
[140] *Id.* at 42.
[141] *Id.* at 11 ("BGE specifically asked E3 to build on its prior efforts in the State by evaluating the implications of decarbonization strategies that achieve the state's newly legislated net zero targets with an intent to understand how BGE's electric and gas businesses and infrastructure could play a supporting role.").

electric and gas infrastructure to achieve decarbonization")[142] can "take advantage of the *existing* BGE gas distribution system to meet heating capacity requirements."[143] In fact, the "existing" infrastructure that BGE seeks to leverage in 2022 is only 30 percent built—BGE's plan to modernize its gas system will not be complete for 20 years.[144]

Second, the *BGE Strategy* appears to be based on numerous analytical flaws, including, but not limited to, the following:

- The report assumes that there will be a continuing need for back-up gas or electric resistance heating systems to accompany the deployment of high efficiency cold-climate air source heat pumps in Maryland.[145]

- The report fails to adequately estimate the reductions in electric demand resulting from the change-out of inefficient electric resistance heating with the highly efficient cold climate air source heat pumps, leading to inaccurate assumptions about electric load growth.

- The report fails to account for the impacts of the policies—including significant tax incentives and rebates—in the Inflation Reduction Act that will accelerate electrification by lowering its costs.

- The report counts biomethane as zero-emission, although when it is burned, it emits carbon that MDE counts in its inventory of Maryland GHG emissions.

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[142] *Id.* at 4.
[143] *Id.* at 32 (emphasis added); *see also id.* at 5 ("Gas infrastructure serves as an existing, low-cost source of capacity that reduces the amount of electric generation, transmission and distribution capacity that will need to be added over the coming decade."); *id.* at 28 ("The gas backup utilizes the existing firm capacity of BGE's gas infrastructure …"); *id.* at 33 ("The Hybrid and Diverse scenarios substantially reduce incremental electric system expenditures by leveraging the existing capacity of BGE's gas infrastructure.").
[144] *But see Gas Spending Report* at 11-13.
[145] *Synapse Report*, Part 3.2, at 6-7.

Third, the *BGE Strategy* is largely based on hypotheses rather than facts. For example, while it purports to achieve decarbonization in line with Maryland's climate change policies, the *BGE Strategy* depends heavily on the large-scale replacement of conventional gas with renewable natural gas ("RNG"), hydrogen, or various types of synthetic gas, which, as discussed above, are not cost-effectively available at scale now, are unlikely to be cost-effectively scalable, and are themselves potential sources of GHG emissions.[146] The *BGE Strategy* admits that its conclusion that "decarbonization strategies that leverage the advantages of both electrification measures and gas infrastructure carry a lower overall level of challenge relative to an all electric approach" is a "hypothesis."[147] Yet BGE's approach seeks to place all the risk for failure of its "hypothesis" on customers. While OPC shares BGE's hope that new technologies will make alternative fuels a more viable alternative, the Commission should make it clear that the gas company—not customers—bears the risk for any strategies that speculate on alternative fuels. As things are now, the gas companies are speculating on the backs of customers by investing massively in infrastructure that locks in costs for 40 or more years, long after fossil gas sales will substantially decline or end altogether.

These failings in the *BGE Strategy* wholly undermine its recommendations and conclusions. Notwithstanding its failings, if the Commission is to consider the strategy, it should be tested and investigated through the comprehensive, broader investigative proceeding that OPC here requests. Failure to engage in proactive, comprehensive,

[146] *See* Part IV.B above.
[147] *BGE Strategy* at 29.

Commission-driven planning would be to defer by default to the gas companies' private plans, such as the *BGE Strategy*. It is the Commission's duty to ensure that utilities operate in the public interest, not merely their own private interests.[148]

V. The Commission should take advantage of existing guidance and resources in deciding how to proceed with gas utility planning.

From the Maryland Commission on Climate Change's *Building Energy Transition Plan*, to independent expert reports, to actions undertaken by other state utility regulators, the Commission has at its disposal significant resources about how best to conduct the long-term gas planning proceeding this petition requests. The gas transition proceedings held by other state regulators are particularly informative. Many of these proceedings point out the same challenges Maryland faces from the transition away from gas to electricity to meet State climate goals. For example, Maryland must address the same issues as the New Jersey Board of Public Utilities pointed out in a 2020 report: "As NJBPU endeavors to ensure just and prudent investments, it must examine if ratepayers are socializing and subsidizing unnecessary fossil fuel infrastructure costs, and if doing so will risk ratepayers shouldering the burden of stranded assets in the future."[149] Having no planning process in place, Maryland is behind New Jersey and other states. The

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[148] PUA § 2-113(a)(1).
[149] *2019 New Jersey Energy Master Plan: Pathway to 2050*, at 191, https://www.nj.gov/emp/.

Commission should use these other states' experience to fashion a proceeding that quickly advances policies necessary to protect customers and Maryland's climate goals.

In part making use of these other states' proceedings, OPC includes in Appendix A a list of issues for the Commission's consideration for the purpose of structuring and defining the scope of the requested proceeding. The remainder of this part (1) highlights relevant recommendations of the MCCC, (2) points out relevant recommendations from independent expert reports, and (3) summarizes gas transition proceedings ongoing in other states. A fuller description of other states' proceedings is provided in Appendix C. Appendix A includes a list of issues for the Commission's consideration for the purpose of structuring and defining the scope of the requested proceeding.

A. The Maryland Commission on Climate Change recommends planning for shrinking gas distribution systems.

In 2021, the MCCC recommended that the Commission oversee the preparation of utility transition plans to achieve a "structured and just transition to a near-zero emissions building sector in Maryland."[150] The MCCC listed the key objectives of the gas transition plans as follows:

- Appropriate gas system investments/divestments for a shrinking customer base and reductions in gas throughput in the range of 50 to 100 percent by 2045
- Comprehensive equity strategy to enable low-to-moderate income households to improve energy efficiency and electrify affordably
- Regulatory, legislative, and other policy changes needed for a managed and just transition of the gas system and infrastructure

[150] *MCCC Transition Plan* at 23.

- Operational practices to meet current customer needs and maintain safe and reliable service while minimizing infrastructure investments
- Assessment of existing gas infrastructure and options for contraction
- Alternative models for the gas utility's long-term role, business model, ownership structure, and regulatory compact, as part of a managed transition[151]

In its *2022 Annual Report*, the MCCC largely restated these recommendations, but made more explicit the pace of the transition, calling on the Commission "to issue orders and regulations by no later than January 1, 2025," and specifically targeting the gas companies.[152] Notably, the MCCC included as an objective of the gas transition plans "appropriate gas system investments/abandonments for a shrinking customer base and reductions in gas throughput in the range of 60 to 100 percent by 2045."[153] The MCCC characterized the recommendation in both its 2021 and 2022 Annual Reports as one directed to the General Assembly—seeking that it mandate the Commission to undertake a process incorporating its recommendations. But, as discussed above, the Commission has the requisite legal authority, and an obligation, to perform these duties now under existing law.[154]

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[151] *Id.*
[152] *MCCC 2022 Annual Report* at 16.
[153] *Id.* at 16-17.
[154] The MCCC's styling of its request as one directed to the legislature to mandate PSC action is an acknowledgement that the Commission has thus far declined to institute such a proceeding despite the apparent need—not as foreclosing the PSC from acting on its own initiative. Indeed, the initial draft of the 2022 recommendation circulated to the MCCC—which was simplified to largely track the 2021 language—stated: "The PSC *thus far* has not engaged in a process to plan for the future of the natural gas utilities and the decrease in gas throughput resulting from electrification *using the legal authority it has now that enables it to do so*." (emphasis added). The recommendation to the legislature, thus, does not limit in any manner the PSC's independent legal authority to implement the MCCC's recommendations.

B. Numerous expert reports describe the benefits of planning and the risks of failing to plan.

A number of expert reports confirm the logic of advance thinking and proactive planning for the impact of technological change and climate policy on gas utilities. According to Brattle, "The transition process will play out over many years, but the planning must start now."[155] Industry experts have described in some detail the need to investigate gas distribution planning procedures and practices in the context of climate change policy implementation. These reports may be of use as the Commission considers the structure of the requested investigation and rulemaking and near-term no-regrets actions. Consider two examples:

- The Regulatory Assistance Project's report, *Under Pressure: Gas Utility Regulation for a Time of Transition,* explains how the interrelated issues of improved electric end-use technologies, increasingly stringent GHG emissions policies, greater awareness of the public health risks associated with fossil gas, and the limitations of alternative fuels, are putting pressure on current gas practices and regulation.[156] The report suggests a range of specific, practical strategies for regulators to consider in facilitating the transition away from gas, including requiring gas companies to develop transition plans to "ensure that regulators, utilities and stakeholders have the information they need to develop pathways that take into account policy goals, changing demand and potential impact to customers;"[157] enhancing energy efficiency and electrification programs to facilitate the gas transition;[158] and reforming gas rate-making to lower short-term barriers and enable an equitable and efficient long-term transition.[159]

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[155] Brattle Grp. at 4.
[156] Megan Anderson et al., *Under Pressure: Gas Utility Regulation for a Time of Transition*, REG. ASSISTANCE PROJECT (May 2021), at 8, 10-15, https://www.raponline.org/wp-content/uploads/2021/05/rap-anderson-lebel-dupuy-under-pressure-gas-utility-regulation-time-transition-2021-may.pdf.
[157] *Id.* at 17-29.
[158] *Id.* at 30-36.
[159] *Id.* at 37-53.

- *Aligning Gas Regulation and Climate Goals, A Road Map for State Regulators,* released by the Environmental Defense Fund, also explains how the traditional policy framework relating to gas supply, use, planning, expansion, cost recovery, and review is misaligned with GHG emissions reduction goals and provides recommendations for regulators to "begin to bridge the disconnect between gas policy and climate commitments."[160] The report sets out specific, actionable recommendations to help regulators (1) "establish inclusive and transparent decision making;"[161] (2) "require rigorous long-term planning;"[162] and (3) "coordinate near-term decisions and long-term goals."[163]

C. The Commission should learn from the proceedings of other state regulators.

The Commission should also consider the actions of other public utility regulators that have already begun comprehensive, long-term planning proceedings to investigate the operations of the gas companies under their jurisdiction. These initiatives demonstrate the challenges of managing an effective transition, including the collateral impacts on ratepayers and other stakeholder groups. While differences in other states' weather, geography, supply portfolio, demographics, and economics must be accounted for, these initiatives nonetheless present valuable lessons from which the Commission can learn in structuring its own proceeding. Given their long timelines, they also demonstrate the

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[160] Natalie Karas et al., *Aligning Gas Regulation and Climate Goals: A Roadmap for State Regulators*, ENVTL. DEF. FUND (Jan. 2021), at 4, 10-11, https://blogs.edf.org/energyexchange/files/2021/01/Aligning-Gas-Regulation-and-Climate-Goals.pdf.
[161] *Id.* at 12-15.
[162] *Id.* at 16-23.
[163] *Id.* at 24-36.

urgency with which the Commission needs to engage immediately in the proactive and comprehensive regulation called for by this petition.

Appendix C details the gas planning and related proceedings in eight jurisdictions of varying sizes, climates, demographics, and economies: California, Colorado, the District of Columbia, Massachusetts, Minnesota, New Jersey, New York, and Rhode Island. Here, we provide brief highlights of the proceedings in each jurisdiction:

1. California

In 2020, the California Public Utilities Commission ("PUC") opened a proceeding to review the issues facing the gas utilities, including ratemaking and avoidance of stranded costs.[164] It grouped the issues into three separate investigative "tracks," including one regarding the anticipated large reductions in gas volumes delivered due to GHG emissions reduction legislation. Under this track, the California PUC is aiming to "determine the regulatory solutions and planning strategy that [it] should implement to ensure that, as the demand for gas declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, and with minimal or no stranded costs."[165]

2. Colorado

In 2020, the Colorado PUC kicked off the first in a series of proceedings to investigate retail gas industry GHG emissions in light of statewide emissions reduction

[164] *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning*, Case No. R20-01-007 (Jan. 27, 2020).
[165] *Id.* at 14.

goals.[166] Recognizing the importance of comprehensive planning to ensure that "broad utility planning and investment protocols are conducted in a manner that are fully cognizant of, and consistent with, statutory emission reduction goals," the Colorado PUC recently took what it described as an "incremental step in the larger evolution of the shifting regulatory framework for the gas industry" by amending its rules governing gas line extension policies and gas infrastructure planning.[167]

3. District of Columbia

In 2020, the D.C. Public Service Commission ("PSC") initiated a comprehensive climate policy proceeding to review the planning, operations, and practices of both its franchised electric distribution company, Pepco, and its franchised gas distribution company, WGL.[168] The D.C. PSC established as its initial scope to "consider whether and to what extent utility or energy companies under our purview are helping the District of Columbia achieve its energy and climate goals and then take action, where necessary, to guide the companies in the right direction."[169]

4. Massachusetts

Responding to a petition by the Massachusetts Attorney General, the Massachusetts Department of Public Utilities ("DPU") opened an investigation in 2020 "into the role of the local distribution companies as the Commonwealth achieves its

[166] *Decision Opening Repository Proceeding; Scheduling Commissioners' Information Meeting; and Designating Hearing Commissioner*, Proceeding No. 20M-0439G (Nov. 4, 2020).
[167] *Commission Decision Adopting Rules*, Proceeding No. 21R-0449G (Dec. 1, 2022), at 31, 13.
[168] Order No. 20662, Case No. 1167 (Nov. 18, 2020).
[169] *Id.* at 4-5.

target 2050 goals."[170] Through this proceeding, the DPU is "explor[ing] strategies to enable the Commonwealth to move into its net-zero greenhouse gas ("GHG") emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of [local distribution companies] in the Commonwealth."[171]

5. Minnesota

In 2021, the Minnesota PUC opened two proceedings to address the role that gas companies play in helping the state reach its emissions reduction goals. The first aimed to guide the gas companies in developing "innovation plans" to decarbonize their operations.[172] The second is a broad proceeding looking at the future of gas, in which the Minnesota PUC is considering policy and regulatory changes needed to meet or exceed the state's climate goals.[173]

6. New Jersey

In 2019, the New Jersey Board of Public Utilities ("BPU") initiated a proceeding to explore whether sufficient capacity exists to deliver natural gas to meet consumer needs.[174] After receiving conflicting reports from the various parties to the proceeding, the New Jersey BPU recognized the need to determine "how evolving environmental

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[170] *Vote and Order Opening Investigation*, Case No. 20-80 (Oct. 29, 2020).
[171] *Id.* at 1.
[172] *Notice of Comment Period on Natural Gas Innovation Act, Section 21*, Docket No. G-999/CI-21-566 (Sept. 3, 2021).
[173] *Notice of New Docket, In the Matter of a Commission Evaluation of Changes to Natural Gas Utility Regulatory and Policy Structures to Meet State Greenhouse Gas Reduction Goals*, Docket No. G-999/CI-21-565 (July 23, 2021).
[174] 2-27-19M, *Decision and Order*, Docket No. GO17121241 (February 27, 2019).

concerns may drive changes in the way natural gas is transported and used in New Jersey."[175] The BPU also serves as the lead agency for development and oversight of the State's *Energy Master Plan*, which the BPU and its partners updated most recently in 2019.[176] The plan directs that "[a]s NJBPU endeavors to ensure just and prudent investments, it must examine if ratepayers are socializing and subsidizing unnecessary fossil fuel infrastructure costs, and if doing so will risk ratepayers shouldering the burden of stranded assets in the future."[177]

7. New York

Recognizing the need for gas utilities to "adopt improved planning and operational practices that enable them to meet current customer needs and expectations in a transparent and equitable way while minimizing infrastructure investments and maintaining safe and reliable service," the New York PSC began proceedings in 2020 to bring long-term gas planning in line with the State's GHG reduction goals.[178] Through the proceeding, the New York PSC has collected supply and demand analyses from the utilities, adopted a proposal from staff to require the utilities to file long-term plans every three years, and ordered the utilities to prepare a study on depreciation practices.[179]

8. Rhode Island

In 2022, the Rhode Island PUC opened a docket to investigate the future of the regulated gas distribution business with the purpose of "examin[ing] the extent to which

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[175] 5-20-20-9A, *Order Soliciting an Independent Consultant*, Docket No. GO19070846, at 4.
[176] *2019 New Jersey Energy Master Plan: Pathway to 2050*, at 190-91, https://www.nj.gov/emp/.
[177] *Id.* at 191.
[178] *Order Instituting Proceeding*, Case No. 20-G-0131 (Mar. 19, 2020), at 2-3.
[179] *Order Adopting Gas System Planning Process*, Case No. 20-G-0131 (May 12, 2022).

the requirements of the [recently passed Act on Climate] impact the conduct, regulation, ratemaking, and the future of gas supply and gas distribution within Rhode Island."[180] The PUC recently adopted a scope for the proceeding, dividing it into three phases—policy planning, technical analysis, and policy development—and laying out a series of questions to be incorporated into each.[181]

CONCLUSION AND REQUESTED RELIEF

Maryland's policies to address climate change for the energy sector seek significant reductions in GHG emissions levels, with interim goals for emissions reduction over the intermediate term. These policies particularly address the State's building sector and call for substantial reductions in the sector's usage of fossil fuels, including fossil gas. As electric technologies continue to advance, and governments at all levels, together with their constituents, implement climate change policies over the next two decades that include switching from fossil fuels to electricity in buildings, the anticipated decreases in gas consumption will have transformative effects on Maryland's gas companies. The transformation will impact all aspects of gas companies' operations—including planning, ratemaking, cost recovery, investment, and procurement activities.

Despite these fundamental impending changes, Maryland's gas companies are embarked on a program of huge investments in their gas utility plant, utilizing historical

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[180] *Notice of Commencement of Docket*, Docket No. 22-01-NG (June 9, 2022).
[181] *Proceeding Scope*, Docket No. 22-01-NG (Jan. 3, 2023).

assumptions about recovery in rates and consumer affordability that are no longer relevant. They continue to deploy operations and practices—for gas procurement, gas-line extensions, marketing, and energy-efficiency programs, among others—that are drastically mis-aligned with the State's climate change policies and the resultant decline in gas usage that even gas companies themselves now anticipate.

The gas companies' investments, operations, and practices, designed as they are for an increasingly bygone era, have dire implications for customers. The gas companies' current business plans—encompassing everything from procurement and line extension polices to massive investments in gas distribution pipes and other infrastructure—threaten to lock customers into massive costs in increasingly inappropriate plant investment as Maryland transitions to a net-zero GHG emissions economy. Such negative potential consequences for Maryland customers call out the urgent need for the Commission to effectively regulate the gas companies in the public interest. The Commission is uniquely positioned, possessing the requisite expertise, legal authorities, and legal obligations, to take a pro-active role to commence a proceeding now, structured to address the issues set forth in this petition.

As explained above, the proceeding should consist of two tracks. One track, the Transition Track, is a proactive and comprehensive investigation that ends in a rulemaking that governs the procedures and requirements for gas utility transition plans. The other, simultaneous track, the Priority Track, would consider near-term, priority actions that gas utilities should take to address current policies adverse to customer interests.

Critical to both tracks are procedures that enable and facilitate transparency. Open and transparent comprehensive proceedings will ensure the broad participation necessary to create public support for gas utility transition plans that have buy-in from all stakeholders, including utilities, consumers, public interest organizations, and others. For both tracks, the procedures must include time allocated for discovery as well as for motions and briefings. Robust public participation and transparency—including, importantly, access to utility information—will facilitate better decision-making and support the legitimacy of the resulting regulations and transition plans.

Respectfully submitted,

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Appendix A

PROPOSED QUESTIONS FOR THE MARYLAND PUBLIC SERVICE COMMISSION TO CONSIDER IN ESTABLISHING THE SCOPE OF THE TRANSITION TRACK

APPENDIX A

Proposed Questions for the Maryland Public Service Commission to Consider in Establishing the Scope of the Transition Track

A. Data Collection

1. What data should the Commission collect from the gas companies to forecast the expected decline in demand for each customer class?

2. What data should the Commission collect from the gas companies to determine actual decline in demand and where it is occurring?

3. What data inputs and assumptions should the Commission require the gas companies to integrate into their gas demand forecasts for each customer class?

4. Should the Commission require the gas companies to report granular data on the location, condition, depreciation schedule, and repair and replacement schedule of their transmission and distribution pipelines?

5. To what extent is the collection of data from Maryland's electric utilities necessary to inform and support long-term gas system planning?

6. What other data is needed from the gas companies to assist the Commission and stakeholders in long-term gas system planning?

B. Long-Term Planning Considerations

1. What actions have the gas companies taken to date to harmonize their long-term planning with Maryland's statutory greenhouse gas (GHG) emissions reduction mandates?

2. What information, forecasts, analyses, and actions should the Commission require the gas companies to include in long-term transition plans?

3. Should plans include all of the following components?

    a. Descriptions of capacity planning models and methodologies

b. Plans for coordinating with electricity providers to meet electric reliability needs

c. Plans for cost-effectively maintaining aging infrastructure

d. Specific steps to transition customers and/or segments of a gas company's service base to electricity

e. Plans for strategically decommissioning or "pruning" parts of the distribution system

4. What additional components should long-term transition plans include?

5. Should the Commission establish uniform reliability and design standards for the gas companies, including uniform standards to forecast demand?

6. Should the Commission establish uniform rules or standards for the procurement of gas supply?

7. Should the Commission require that long-term transition plans meet near-term and/or long-term GHG emissions reduction targets or any other goals prescribed by the Commission or the State? If so, what targets and goals should plans include?

8. What is the proper time horizon for long-term transition plans?

9. What standards and criteria should the Commission use to evaluate and approve or disapprove long-term transition plans?

10. What stakeholder and public input processes should the Commission prescribe for the development and evaluation of long-term transition plans?

11. Should the Commission establish a process in which decisions made in this proceeding can be reevaluated over certain time intervals or in the face of changing conditions such as updated weather forecasts and new technologies?

12. Should cost recovery issues arising from the implementation of a gas company's long-term transition plans be addressed in each company's general rate case or in a separate proceeding?

13. How should the gas companies' obligations to customers be defined, given the State's decarbonization goals? What regulatory or statutory changes are needed?

14. What gas company workforce considerations are raised by a transition away from gas, and how should these be included in the long-term gas planning process?

C. Potential Substitutes for Fossil Gas

1. To what extent are potential substitutes for conventional fossil gas—such as "renewable natural gas" (RNG), "responsibly sourced gas" (RSG or "certified gas"), and hydrogen—commercially available and cost-effective?

2. At what scale are such alternative fuels commercially available now and expected to be available in the future, relative to the current demand for gas by the utility sector and other sectors?

3. Are such alternative fuels compatible with (i) the gas companies' existing gas delivery infrastructure, and (ii) consumer appliances?

4. Should procurements of such alternative fuels be included in the gas companies' standard commodity supply offered to customers?

5. What new transmission infrastructure is needed for the gas companies to include alternative fuels in their supply procurements?

6. Should the Commission establish uniform standards for interconnection and cost allocation of RNG or hydrogen facilities and related infrastructure?

7. Should the Commission consider minimum GHG intensity standards for alternative fuels procured by the gas companies?

D. Gas infrastructure

1. What methodology should the Commission use to determine whether the gas companies' infrastructure portfolios are consistent with the State's GHG emissions reduction mandates and the gas companies' obligations to customers within their service territories?

2. As gas demand declines in accordance with Maryland's GHG emissions

reduction goals, what gas infrastructure will be needed to ensure safe and reliable gas service: (i) between now and 2031, when emissions must be reduced to 60% below 2006 levels, (ii) between 2031 and 2045, when emissions must be reduced to net zero, and (iii) beyond 2045?

3. For each of the three time horizons identified above:

   a. What assumptions are necessary to determine how much infrastructure is needed?

   b. As gas throughput declines, what criteria and processes should be used to identify infrastructure that can be decommissioned without compromising reliability?

   c. How should the Commission manage gas infrastructure to mitigate stranded costs and operations and maintenance expenses caused by declining throughput?

   d. Should the Commission consider targeted infrastructure decommissioning?

   e. Should the Commission consider accelerated depreciation?

4. Should the Commission require site-specific approvals for gas infrastructure projects that exceed a certain size or cost?

5. Should the Commission establish technical and operational standards for leak detection to ensure that repair and replacement activities are prioritized appropriately?

6. How should the Commission ensure that leak detection standards applicable to gas companies incorporate technological advances and improvements in best practices?

7. When a gas company requests ratepayer funds to upgrade aging infrastructure, what criteria should the Commission use to determine whether the infrastructure should be repaired, replaced, or decommissioned?

   a. Should the Commission require the gas company to provide information on the methods it has used and actions it has taken to detect and repair leaks?

b. Where it is necessary to repair or replace infrastructure, should the Commission adopt standards that prioritize repair over replacement?

c. Should repair or replacement criteria depend on whether the infrastructure is necessary to meet the gas company's design standard?

d. How should the cost to repair or replace the infrastructure be balanced against the safety and reliability benefits of the repair?

e. What pipeline-related characteristics should be considered when determining whether to repair or replace distribution infrastructure (e.g., safety, age of pipe, pipe material)?

f. What community characteristics, such as designation as an underserved community (as defined under Environment Art. sec. 1-701), should be considered?

g. What goals should be considered in determinations about repairing or replacing infrastructure (e.g., cost savings, minimizing stranded assets, pipeline safety, net greenhouse gas reductions, environmental justice)?

h. What non-pipeline alternatives should be considered?

i. How should the cost of non-pipeline alternatives be compared to the cost of gas pipeline replacement or repair?

8. How should avoided operations and maintenance (O&M) and infrastructure replacement costs for decommissioning distribution pipelines be estimated and incorporated into cost effectiveness analysis?

9. For prioritizing distribution and transmission lines for decommissioning, what pipeline-related characteristics should be considered (e.g., safety, age of pipe, depreciation schedule, pipe material location or customer density, type of load or customer served, proximity to a lower-carbon source of gas)?

10. What procedural mechanism should be used to proactively decommission

distribution pipelines?

11. If the Commission determines that a distribution pipeline should be decommissioned,

    a. What notice, timing, and public input standards should apply?

    b. What planning and procedures are necessary to ensure that there is sufficient local electric capacity available to reliably serve customers that move off the gas system?

    c. Are there health and safety issues that need to be addressed from decommissioned distribution lines?

12. What infrastructure is needed to fulfill the needs of customers who are likely to remain on the gas system the longest, such as electric generators or difficult-to-electrify industrial users?

13. What should be the role of existing gas storage facilities as a component of the gas companies' infrastructure portfolio?

14. Should the Commission require the achievement of certain milestones (e.g., replacement energy resources are built and operational) before a significant gas asset is decommissioned?

15. How should the Commission consider the need for gas infrastructure that may be needed to serve new industrial gas customers in difficult-to-electrify sectors as part of the long-term gas system planning process?

16. What should the regulatory process be for de-rating a transmission pipeline to a distribution pipeline?

E. Rate Design and Cost Allocation

1. As customers migrate to electricity, how can the Commission ensure just, reasonable, and nondiscriminatory rates and service?

2. Should the Commission reconsider rate design and cost allocation methods currently employed by gas companies?

3. Do current rate design and cost allocation methodologies raise particular concerns for low-income customers and customers in disadvantaged communities?

4. What structural, policy, economic, accessibility, and other barriers do low-income customers and disadvantaged communities face regarding the transition away from gas, and how can the commission take action to address those barriers?

5. How will EmPOWER be impacted by any proposed rate design changes?

6. How can the Commission ensure that rates are allocated appropriately between current and future ratepayers?

7. Should the Commission consider new financial mechanisms to allocate costs between current and future ratepayers?

8. If the Commission pursues alternative depreciation methods, are there any rate protections for low-income and disadvantaged customers that the Commission should consider to mitigate any resulting near-term rate increases?

9. Are any additional measures needed to ensure that the gas companies remain financially viable and credit-worthy for as long as gas is necessary for energy reliability?

F. Workforce Issues

1. What authority does the Commission have to address gas company workforce issues?

2. Should the Commission consider measures to ensure a qualified gas workforce continues to be available to operate the gas companies' systems safely throughout the transition away from gas? If so, what measures should be considered?

3. How can any potential negative impacts on gas industry workers be mitigated?

    a. Which employees are likely to be at greatest risk of job loss from a transition away from gas? What are the characteristics of those jobs and work? What types of jobs could such workers transition to?

b. What share of the gas company workforce at greatest risk of job loss is suitable for early retirement? Should the gas companies develop plans to support early retirement for affected employees?

c. Does the Commission have a role in ensuring what types of retraining should be made available to the gas company employees, including training necessary for gas workers in disadvantaged or low-income communities?

4. What are the potential costs associated with workforce mitigation strategies? Who should be responsible for paying these costs?

5. Should the Commission establish requirements for tracking data on implementation of mitigation measures, including retraining, job quality, and job access?

G. Legislation

1. For any issues identified for which the Commission lacks authority, should the Commission:

   a. not address the issue as part of its long-term planning?

   b. request the General Assembly to provide it additional authority?

   c. inform the General Assembly and recommend another State agency address the issue?

Appendix B

PROPOSED ORDER

APPENDIX B

Proposed Order

1. The Commission establishes a docket to solicit comments on the Office of People's Counsel petition for gas utility transition planning and priority actions.

2. Within 30 days of the issuance of this order, interested parties shall file initial comments on the proposal for:

    a. A "Priority Track" covering gas utility practices and operations that should be taken in the short term to ensure practices and operations are consistent with the public interest, just and reasonable rates, and the State's greenhouse gas reduction goals; and

    b. A "Transition Track" on the future role of Maryland's gas utilities in anticipation of, among other possible changes, substantial declines in gas sales and a shrinking customer base.

3. The Commission welcomes specific comments on (i) the questions proposed in OPC's petition Appendix A, (ii) any additional proposed questions for a Transition Track, (iii) the Priority Track issues identified by OPC, and (iv) any additional proposed priority actions.

4. Interested parties shall file comments responsive to initial comments within 30 days from the date initial comments are due.

5. Following receipt of comments, the Commission will schedule a hearing on the scope of the proposed proceeding and, as appropriate, procedures and schedules, after which it will issue a written decision.

So ordered.

Appendix C

COMPREHENSIVE PLANNING PROCEEDINGS
IN OTHER STATES

APPENDIX C

Comprehensive Planning Proceedings in Other States

State	Proceeding #
California	R19 01-011, R20-01-007
Colorado	21R-0449G
District of Columbia	FC1167, GD2019-04-M
Massachusetts	20-80
Minnesota	G-999/CI-21-565, G-999/CI-21-566
New Jersey	GO17121241, GO19070846
New York	20-G-0131
Rhode Island	22-01-NG

1. California

Like Maryland, California has set aggressive GHG emissions reduction goals in recent years.[1] New legislation signed into law in September of 2022 codified the state's most ambitious goal yet to achieve net zero emissions no later than 2045 and reduce statewide anthropogenic GHG emissions to at least 85 percent below 1990 levels by 2045.[2] Additional legislation set interim targets for these reductions, calling for eligible renewable energy resources and zero-carbon resources to supply 90 percent of all retail sales of electricity to California end-use customers by 2035, 95 percent of all retail sales of electricity to California end-use customers by 2040, 100 percent of all retail sales of electricity to California end-use customers by 2045, and 100 percent of electricity procured to serve all state agencies by 2035.[3]

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[1] *See e.g.* California Global Warming Solutions Act of 2006, 2006 Cal. Legis. Serv. Ch. 488 (codified at Cal. Health & Safety Code § 38500, et seq.) (requiring that the state reduce its GHG emissions to 1990 levels by 2020); California Global Warming Solutions Act of 2006: emissions limit, 2016 Cal. Legis. Serv. Ch. 249 (codified at Cal. Health & Safety Code § 38566) (further requiring that GHG emissions are reduced to 40 percent below the 1990 levels by 2030); 100 Percent Clean Energy Act of 2018, 2018 Cal. Legis. Serv. Ch. 312 (codified at Cal. Pub. Util. §§ 399.11, 399.15, 399.30 & 454.53) (targeting 60 percent renewable energy by 2030 and 100 percent by 2045); California Gov. Exec. Order B-55-18 (Sep. 10, 2018) (setting a statewide goal to reach carbon neutrality no later than 2045).
[2] The Climate Crisis Act, 2022 Cal. Legis. Serv. Ch. 337 (Sept. 16, 2022) (codified at Cal. Health & Safety Code § 38562.2).
[3] Clean Energy, Jobs and Affordability Act of 2022, 2022 Cal. Legis. Serv. Ch. 361 (Sept. 16, 2022) (codified at Cal. Gov't Code § 7921.505; Cal. Health & Safety Code § 38561; Cal. Pub. Util. Code §§ 454.53, 454.59, 583, 739.13; Cal. Water Code § 80400).

2018 legislation also specifically targeted the California PUC, requiring the PUC to work with other agencies to assess the potential for reducing GHG emissions from buildings by at least 40 percent below 1990 levels by 2030,[4] and to oversee the development of two new building decarbonization programs.[5] In response, the PUC instituted several of its own proceedings. The first was a rulemaking to support decarbonization of buildings,[6] in which the PUC recently issued a decision eliminating subsidies for new gas line hookups.[7] According to the PUC:

> This will eliminate a financial incentive for expanding the natural gas system to serve new buildings, accelerating the electrification of homes and commercial buildings, and reduce the risk of stranded assets, saving ratepayers approximately $164 million every year. These changes move the state closer to meeting its ambitious goals of reducing greenhouse gas, combating climate change, and attaining a decarbonized energy system.[8]

Second, the PUC opened a generic proceeding to address the long-term planning issues affecting the gas utility companies, as well as to address concerns about operational reliability.[9] The PUC subsequently issued three "scoping orders" defining the issues to be investigated during the proceeding.[10] The PUC directed that the proceeding include a review of important issues facing the gas utilities subject to its jurisdiction, including ratemaking and avoidance of stranded costs. The PUC has grouped the issues into three separate investigative "tracks," arising from (1) ongoing operational issues and constraints (designated Track 1A), (2) gas pipeline and storage safety-related incidents (following on the PG&E/San Bruno explosion and the SoCalGas Aliso Canyon gas storage field leak) (designated Track 1B), and (3) the anticipated large reductions in gas volumes delivered due to GHG emissions reduction legislation (designated Track 2 of the proceeding).[11] Under Track 2, the PUC aimed to "determine the regulatory solutions and

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[4] Zero-Emissions Buildings and Sources of Heat Energy, 2018 Cal. Legis. Serv. Ch. 373 (Sept. 13, 2018) (codified at Cal. Pub. Res. Code § 25403).

[5] Low-Emissions Buildings and Sources of Heat Energy, 2018 Cal. Legis Serv. Ch. 378 (Sept. 13, 2018) (codified at Cal. Pub. Util. Code §§ 748.6, 910.4, 921-22).

[6] *Order Instituting Rulemaking Regarding Building Decarbonization*, Case No. R.19-01-011 (Feb. 8, 2019).

[7] *Decision 22-09-026*, Case No. R19-01-011 (Sept. 20, 2022).

[8] *CPUC Decision Makes California First State in Country to Eliminate Natural Gas Subsidies*, CAL. PUC (Sept. 15, 2022), https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-decision-makes-ca-first-state-in-country-to-eliminate-natural-gas-subsidies.

[9] *Order Instituting Rulemaking to Establish Policies, Processes and Rules to Ensure Safe and Reliable Gas Systems in California and perform Long-Term Gas System Planning*, Case No. R20-01-007 (Jan. 7, 2020).

[10] *Scoping Memo and Rulings*, Case No. R20-01-007 (Apr. 23, 2020) (Oct. 14, 2021) (Jan. 5, 2022).

[11] *Order Instituting Rulemaking* at 3, 10-12 (specifically discussing GHG emissions reductions developments).

planning strategy that the Commission should implement to ensure that, as the demand for natural gas declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, and with minimal or no stranded costs."[12]

In July of 2022, the PUC issued a proposed decision on Track 1A & 1B issues regarding reliability and market structure.[13] More relevant to this petition, in December of 2022, the PUC adopted a general order developed under Track 2—analogous to its pre-existing general order for electric infrastructure projects—requiring gas corporations to (1) submit an annual report of planned gas investments for comment and (2) seek PUC approval for gas infrastructure projects of $75 million or more and those expected to have significant air quality impacts.[14] According to the PUC, "[t]his portion of Track 2, consideration of a gas infrastructure [general order], addresses an identified gap in the Commission's active regulation of gas infrastructure. It also serves as an intermediary step towards development of a more a comprehensive long-term gas planning process later in this proceeding."[15] In its order, the PUC offered the following explanation of the need to adopt a general order as an immediate interim step, which the Commission may wish to consider:

> [W]ork to advance California's landmark greenhouse gas emission reduction goals has led to steadily declining gas consumption levels within California, at the rate of approximately one percent annually. Declining gas consumption levels in turn have three main causes: the installation of more renewable electricity resources on the grid, city ordinances banning the installation of gas appliances in new homes and commercial buildings, and progression of the State's building code toward all electric buildings. As more renewable electricity resources are installed, demand for gas-powered base load generation declines. Senate Bill (SB) 1477 promotes decarbonization of California's building supply. Incentive programs and pilot projects to advance building decarbonization are rapidly emerging. As of Fall 2022, nearly 50 cities and counties in California have adopted local ordinances requiring all-electric appliances in new homes or buildings, in some form. These trends and related decreases in natural gas consumption in California are predicted to continue, particularly with the passage of Assembly Bill (AB) 1279 establishing an economywide target of carbon neutrality by 2045. This decline in demand means there may be less need for large gas infrastructure projects in the future. It also means there may be a

[12] *Id.* at 14.
[13] *Decision 22-07-00*, Case No. R20-01-007 (July 20, 2022).
[14] *Decision Adopting Gas Infrastructure General Order*, Case No. R20-01-007 (Dec. 8, 2022), at 2.
[15] *Id.* at 3-4.

> declining customer base across which to distribute the costs of existing and any new infrastructure. Together, these trends amplify the Commission's responsibility to carefully scrutinize large gas infrastructure projects to ensure they are necessary. If a given facility is not necessary over its estimated useful life, a project could become a "stranded asset," imposing costs but providing limited benefits to a declining pool of ratepayers and increasing rates for the customers left behind on the gas system. Alternatively, some projects may be necessary for reliability in the next 10 to 25 years, even if they are not used for their full useful life. This balance between reliability and cost requires careful scrutiny in the years ahead.
>
> The GO we adopt here provides a mechanism for project review for large and environmentally significant gas infrastructure projects in the near term as we continue to work towards developing a long-term gas planning process and strategy later in this proceeding. The long-term gas planning process and strategy will consider additional ways to avoid the risk of stranded assets and may build upon or refine the GO we adopt here.[16]

Even more recently, the PUC directed gas utilities and other interested stakeholders to comment on staff's proposed *Gas Distribution Decommissioning Framework*, which suggests a framework for gas infrastructure decommissioning in support of the state's climate goals.[17]

The same trends are converging here in Maryland, resulting in the same need for immediate action towards comprehensive, long-term planning. The extensive work the California PUC has done in scoping its proceedings helps to inform the issues OPC proposes the Commission consider in establishing the scope of a similar proceeding in Maryland.[18]

2. Colorado

The Colorado PUC has also taken action in recent years to align the utilities under its jurisdiction with the state's goals to reduce GHG emissions: by 26 percent by 2025, 50 percent by 2030, and 90 percent by 2050, all measured against 2005 levels.[19] In its *2020 Operational Modernization Plan,* the Colorado PUC committed to "explore the electric

[16] *Id.* at 10-12 (internal citations omitted).
[17] *ALJ's Ruling Directing Parties to File Comments on Staff Gas Infrastructure Decommissioning Proposal*, Case No. R20-01-007 (Dec. 22, 2022).
[18] *See* Appendix A.
[19] Climate Action Plan to Reduce Pollution, HB19-2061 (codified at Colo. Rev. Stat. § 25-7-102(2)).

and natural gas utility systems required by Colorado in the future, examining electricity storage, beneficial electrification, and GHG emissions reductions for the purpose of proactively applying consistent policy directives across various dockets in accordance with the Commission's strategic plan."[20] Around the same time, the PUC kicked off a series of relevant proceedings when it approved a settlement including provisions in which the parties agreed to collaborate on a petition for rulemaking to address short-term (5-year) natural gas capacity and infrastructure planning.[21] The PUC later denied the request to open a rulemaking to implement the proposed rules, opting instead to address short-term and long-term planning together.[22] In November of 2020, the PUC opened a proceeding to serve as a repository for presentations, comments, and other materials related to its investigation of retail natural gas industry GHG emissions in light of the statewide greenhouse gas emissions reduction goals.[23] The PUC explained its reasons for opening the proceeding as follows:

> Potential changes to the business model or scale of usage are of great consequence to the Commission in ensuring effective regulation of the natural gas sector. The Commission is responsible for regulation of several aspects of the retail natural gas industry in Colorado including rate setting, system safety and integrity riders, demand-side management programs, reliability of service, and gas pipeline safety. This market uncertainty and the relatively short timeline to make significant progress on the statutory greenhouse gas emission reduction goals makes it important for the Commission to obtain more information about potential impacts to utility systems and how those impacts may affect utility investments and the rates utilities charge Colorado customers.[24]

The PUC held three Commission information meetings under this proceeding before the Colorado legislature passed several new climate measures that affect the work of the PUC in 2021. This included HB 21-1238, requiring gas utilities to file long-term demand side management planning applications to develop energy savings targets;[25] SB 21-246,

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[20] Colo. Dep't of Reg. Agencies: Pub. Utilities Comm'n, *The Colorado Public Utilities Commission's Operational Modernization Plan* (Sept. 2020), at 5 https://puc.colorado.gov/puc-modernization-plan.
[21] *Unopposed and Comprehensive Amended Stipulation and Settlement Agreement to Reflect Corrections*, Proceeding No. 20AL-0049G (Sept. 22, 2020), at 20-21.
[22] *Commission Decision Declining to Accept Petition for Rulemaking*, Proceeding No. 21M-0168G (July 23, 2021).
[23] *Decision Opening Repository Proceeding; Scheduling Commissioners' Information Meeting; and Designating Hearing Commissioner*, Proceeding No. 20M-0439G (Nov. 4, 2020).
[24] *Id.* at 2-3.
[25] Public Utilities Commission Modernize Gas Utility Demand-side Management Standards, HB 21-1238 (codified at Colo. Rev. Stat. §§ 40-3.2-103, 40-3.2-106, and 40-3.2-107).

adopting new requirements for utilities to develop beneficial electrification plans;[26] and SB 21-264, requiring Colorado gas utilities with more than 90,000 retail customers to develop, file, and acquire Commission approval of comprehensive Clean Heat Plans designed to achieve GHG emissions reductions.[27] SB 21-264 also directed the Commission to create rules that require gas utilities to file Clean Heat Plans and take other actions to reduce carbon emissions.[28] In January of 2021, Colorado released its *Greenhouse Gas Pollution Reduction Roadmap*, which lays out a pathway to achieving these goals.[29]

In response, the Colorado PUC opened a new proceeding to collect comment and information from utilities and interested stakeholders regarding proposed rulemakings required under the new laws.[30] In so doing, the PUC recognized "that state-mandated required GHG emission reductions will inevitably have an impact on gas utilities' investments, sales, depreciation schedules, revenue requirements, and rates."[31] In October of 2021, the PUC issued a notice of proposed rulemaking to make substantial revisions to the state's gas utility regulations to reduce the sector's GHG emissions and align infrastructure planning with statewide emissions reductions goals.[32] The proposed rules aimed to improve planning to protect the public interest by establishing a process to determine the need for additional investment and spending, consistent with new climate considerations.

Specifically, the amendments revise the rules governing (1) utility line extension policies, requiring them to be based on the principle that the connecting customer pays its share of the estimated full incremental cost of growth, and (2) infrastructure planning, requiring gas utilities to file a gas infrastructure plan for PUC approval every two years and to seek PUC approval for construction and operation of a facility, or an extension or expansion of a facility of a certain size. After holding multiple workshops and public hearings on the proposed amendments, the PUC issued a decision adopting the amendments on Dec. 1, 2022.[33] In so doing, the PUC explained that "additional insights into system planning, forecasting and investments as provided by the Gas Infrastructure Planning Rules provides a necessary component of the regulatory structure going forward

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[26] Electric Utility Promote Beneficial Electrification, SB 21-246 (codified at Colo. Rev. Stat. §§ 38-33.3-106.7, 40-1-102, and 40-3.2-105.6, -106, and -109).
[27] Adopt Programs Reduce Greenhouse Gas Emissions Utilities, SB21-264 (codified at Colo. Rev. Stat. § 40-3.2-108).
[28] Colo. Rev. Stat. § 40-3.2-108(5).
[29] Colo. Energy Office, *GHG Pollution Reduction Roadmap*, https://energyoffice.colorado.gov/climate-energy/ghg-pollution-reduction-roadmap.
[30] *Decision Opening Miscellaneous Proceeding to Engage with Gas Utilities and Interested Stakeholders and Collect Comment and Information to Inform Future Commission Rulemaking Proceedings*, Proceeding No. 21M-0395G (Aug. 25, 2021).
[31] *Id.* at 9.
[32] *Notice of Proposed Rulemaking*, Proceeding No. 21R-0449G (Oct.1, 2021).
[33] *Commission Decision Adopting Rules*, Proceeding No. 21R-0449G (Dec. 1, 2022).

to ensure appropriate oversight of long-term and costly investments in gas system infrastructure."[34] The Colorado PUC emphasized the importance of comprehensive planning[35] and like the California PUC, described "this rulemaking as one incremental step in the larger evolution of the shifting regulatory framework for the gas industry."[36] Again, the same need exists here in Maryland for the immediate commencement of comprehensive planning.

3. District of Columbia

Like Maryland, the District of Columbia has enacted aggressive targets to address the effects of climate change. Recently amended legislative commitments call for a 60 percent reduction in District-wide GHG emissions by 2030 (relative to 2006 levels) and carbon neutrality by 2045.[37] As did Montgomery County, Maryland, the District also recently passed amendments to its building code requiring that all new construction or substantial improvements of "covered buildings" (including commercial buildings, multifamily buildings, and single family buildings over three stories) be constructed to be net zero and prohibiting most uses of gas in covered buildings.[38]

Similar to the Maryland Commission's obligation to consider "the preservation of environmental quality, including protection of the global climate … and the achievement of the State's climate commitments for reducing statewide, greenhouse gas emissions,"[39] the DC PSC is statutorily required to consider "the conservation of natural resources, and the preservation of environmental quality, including effects on global climate change and the District's public climate commitments."[40] The DC PSC has interpreted this mandate as requiring it to proactively consider how the District's GHG reduction targets impact the long-term planning of its regulated gas and electric utilities. As a result, in November of 2020, the PSC initiated a comprehensive climate policy proceeding to review the planning, operations, and practices of both its franchised electric distribution company, Pepco, and its franchised gas distribution company, WGL.[41]

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[34] *Id.* at 13.
[35] *Id.* at 31 ("A comprehensive approach also ensures broad utility planning and investment protocols are conducted in a manner that are fully cognizant of, and consistent with, statutory emission reduction goals.").
[36] *Id.* at 13.
[37] Climate Commitment Act of 2022, 69 D.C. Reg. 009924 (July 27, 2022) (codified at D.C. Code § 8-151.09d).
[38] Clean Energy DC Building Code Amendment Act of 2022, 69 D.C. Reg. 009924 (Aug. 5, 2022) (codified at D.C. Code § 6–1453.01).
[39] PUA §§ 2-113(a)(2)(v)-(vi).
[40] Clean Energy DC Omnibus Amendment Act of 2018, 66 D.C. Reg. 1344 (Feb. 1, 2019) (codified at D.C. Code § 34-808.02).
[41] Order No. 20662, Case No. FC1167 (Nov. 18, 2020).

The PSC established the initial scope of the proceeding to "consider whether and to what extent utility or energy companies under our purview are helping the District of Columbia achieve its energy and climate goals and then take action, where necessary, to guide the companies in the right direction."[42]

The PSC consolidated into this new proceeding its existing investigation of WGL's climate change plans, which it was previously considering as part of WGL's compliance with conditions to the Altagas merger approval.[43] In subsequent orders, the DC PSC directed Pepco and WGL to file climate change plans[44] and requested briefing on its authority to order electrification.[45] At the end of September of 2022, interested parties began submitting their briefs.

The PSC also opened a generic proceeding to establish integrated metrics for addressing climate change across the electric and gas companies subject to its jurisdiction.[46] In November of 2021, a working group submitted a 300+ page report to the PSC regarding a framework for compliance with the Clean Energy Act. The PSC has not yet issued an order on the working group's recommendations.

Although still mid-stream, the PSC's comprehensive investigation has advanced well beyond the incipient present status of matters before the Maryland Commission. The PSC's investigation and its outcome is likely to have direct relevance to WGL's operations in Maryland, given the integrated nature of much of WGL's gas infrastructure and operations in Maryland and the District. It also provides another model for taking proactive action to consider long-term planning comprehensively, rather than piecemeal in individual proceedings.

4. Massachusetts

Massachusetts, too, has launched aggressive legislative efforts to reduce GHG emissions. Current reduction goals were codified in 2021, targeting net zero GHG

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[42] *Id.* at 4-5.
[43] *Id.* (converting proceeding to address WGL's merger settlement compliance filing regarding climate change in Case No. FC1142 into new proceeding, Case No. FC1167, to address proposals requested from WGL and Pepco to "assist the District in meeting and advancing [the District's] climate goals.").
[44] Order No. 20754, Case No. FC1167 (June 4, 2021), at 16-17.
[45] *Request for Briefs*, Case No. FC1167 (July 12, 2022), at 2.
[46] *Notice of Inquiry*, Case No. GD2019-04-M (Sep. 26, 2019).

emissions by 2050, with interim targets of 50 percent by 2030 and 75 percent by 2040 (as measured against 1990 baseline emissions).[47]

In June of 2020, the Massachusetts Attorney General filed a petition with the Massachusetts DPU asking the DPU to initiate a generic proceeding to update the long-term planning activities of the gas companies in the context of the state's efforts to reduce its GHG emissions.[48] Following the Attorney General's petition, the DPU issued an order opening an investigation "into the role of the local distribution companies as the Commonwealth achieves its target 2050 goals."[49] In the order, the DPU described the goals of the proceeding as follows:

> [W]e will explore strategies to enable the Commonwealth to move into its net-zero greenhouse gas ("GHG") emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth.[50]
>
> ...
>
> Through this proceeding the Department will solicit utility and stakeholder input and develop a regulatory and policy roadmap to guide the evolution of the gas distribution industry, while providing ratepayer protection and helping the Commonwealth achieve its goal of net-zero GHG emissions energy.[51]

The DPU required responsive compliance filings by each of the individual gas utilities, set out specific questions to be pursued during the proceeding, and called for the utilities to arrange for an independent consultant study and report on the gas utilities' filings.[52] Despite the insistence of various stakeholders, the DPU declined to oversee the independent study itself.[53] In March of 2022, the gas utilities collectively submitted the required independent study and report as well as required individual Initial Net Zero Enablement Plans. The DPU held two virtual public hearings, two virtual technical sessions, and a discovery period and accepted final stakeholder comments. The DPU then intended to make certain determinations and issue guidance in the form of an order to establish the future steps.[54]

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[47] An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy, 2021 Mass. Acts Ch. 8 (codified at Mass. Gen. Laws Ch. 21N, § 3 et seq.).
[48] *Petition of the Office of the Attorney General,* Case No. 20-80 (June 4, 2020).
[49] *Vote and Order Opening Investigation*, Case No. 20-80 (Oct. 29, 2020).
[50] *Id.* at 1.
[51] *Id.* at 4.
[52] *Id.* at 4-5.
[53] *Order on the Attorney General's Motion for Clarification*, Case No. 20-80 (Feb. 10, 2021).
[54] *Hearing Officer Memorandum Regarding Stakeholder Final Comment Deadline*, MA DPU Case No. 20-80 (Sept. 8, 2022).

On August 11, 2022, however, the Governor signed into law new climate legislation that, among other things, addresses the future of gas.[55] News coverage described relevant provisions as "tak[ing] aim at the Department of Public Utilities' ongoing work on the future of natural gas in the state. The department has been criticized for letting the utility companies write their own plans, and this law gives environmental groups and the public a bigger role in the planning process."[56]

The new law requires DPU to "convene a stakeholder working group to develop recommendations for regulatory and legislative changes that may be necessary to align gas system enhancement plans … with the applicable statewide greenhouse gas emission limits and sublimits … and the commonwealth's emissions strategies."[57] The working group is required to submit its report to DPU and others no later than July 31, 2023. The law also prohibits DPU from approving "any company-specific plan filed pursuant to the DPU Docket No. 20-80, … prior to conducting an adjudicatory proceeding with respect to such plan."[58] Such legislative action provides a cautionary note about the risks of allowing the planning proceeding to be too heavily led by the utilities themselves. As identified by numerous stakeholders in the Massachusetts proceeding, and ultimately embodied by the recent legislation, Commission oversight is necessary to ensure that planning prioritizes the public interest over utilities' private interests.

5. Minnesota

In 2007, Minnesota passed legislation establishing statewide goals to reduce GHG emissions by 15 percent, as compared to 2005 levels, by 2015; 30 percent by 2025; and 80 percent by 2050.[59] In 2021, the state passed additional legislation, the Natural Gas Innovation Act (NGIA), designed to encourage natural gas utilities to develop "innovative resources" to help the state reach its GHG emissions reduction goals.[60] Under the 2021 law, gas utilities can file with the Minnesota PUC "innovation plans" for the development or provision of "innovative resources" that decarbonize their operations.[61] If approved by the PUC, the "prudently incurred costs" associated with these pilot programs can be recovered through rates.

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[55] An Act Driving Clean Energy & Offshore Wind, 2022 Mass. Acts Ch. 179 (August 11, 2022).
[56] Miriam Wasser, *What to Know about the New Mass. Climate Law*, WBUR (last updated Aug. 11, 2022), https://www.wbur.org/news/2022/07/22/massachusetts-climate-bill-baker-desk.
[57] An Act Driving Clean Energy & Offshore Wind at § 68.
[58] *Id.*at § 77.
[59] Next Generation Act of 2007, 2007 Minn. Laws Ch. 136 (codified at Minn. Stat. § 216H.02).
[60] Natural Gas Innovation Act, 2021 (1st Spec. Sess.) Minn. Laws Ch. 4 (codified at Minn. Stat. §§ 216B.2427 & 216B.2428).
[61] "Innovative resources" are defined in the law as "biogas, renewable natural gas, power-to-hydrogen, power-to-ammonia, carbon capture and utilization, strategic electrification, district energy, and energy efficiency." Minn. Stat. § 216B.2427.

In response to the NGIA, the PUC opened two dockets. The first docket, directed by the NGIA, aimed to guide the gas companies in developing innovation plans by establishing (1) frameworks for comparing the lifecycle GHG emissions intensities of "innovative resources," and (2) cost-benefit analysis to compare the cost effectiveness of innovative resources and innovation plans that gas utilities file under the Act.[62] In June, the PUC issued an order adopting the required frameworks,[63] and soon thereafter adopted eligibility criteria for energy efficiency and strategic electrification investments proposed and implemented under the NGIA.[64]

More directly analogous to the proceeding requested by this petition, the PUC's second docket is a broader proceeding looking at the future of gas, in which the PUC is considering policy and regulatory changes needed to meet or exceed the state's climate goals.[65] The PUC is currently in the process of holding a series of technical conferences as a primer to interested parties on the existing state of gas regulation and issues.[66]

6. New Jersey

New Jersey has similarly positioned itself as a national leader in developing a cleaner energy future. In 2007, the New Jersey Global Warming Response Act directed state agencies to develop plans and make recommendations for reducing emissions of climate pollutants to 80 percent below their 2006 levels by the year 2050.[67] In 2018, Executive Order No. 28 further directed the development of an updated statewide *Energy Master Plan* to achieve 100 percent clean energy by 2050 and tasked the New Jersey BPU to serve as the lead agency for development and oversight.[68] In January of 2020, the BPU and its partners released the updated plan, which among other things, highlights the tension between the need to maintain safe and reliable gas infrastructure and service on the one hand, and the incompatibility of gas infrastructure expansion with the state's GHG emissions reduction goals on the other.[69] The Plan directs that "[a]s NJBPU endeavors to ensure just and prudent investments, it must examine if ratepayers are socializing and subsidizing unnecessary fossil fuel infrastructure costs, and if doing so will risk ratepayers shouldering the burden of stranded assets in the future."[70]

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[62] *Order Establishing Frameworks for Implementing Minnesota's Natural Gas Innovation Act*, Docket No. G-999/CI-21-566 (June 1, 2022).
[63] *Id.*
[64] *Order Adopting Eligibility Criteria for Energy Efficiency and Strategic Electrification Investments*, Docket No. G-999/CI-21-566 (Sept. 12, 2022).
[65] *Notice of New Docket*, Docket No. G-999/CI-21-565 (July 23, 2021).
[66] *Notice of Second Technical Conference*, Docket No. G-999/CI-21-565 (Nov. 17, 2022).
[67] New Jersey Global Warming Response Act, P.L. 2007 Ch. 340 (Jan. 13, 2008) (codified at N.J. Rev. Stat. §§ 26:2C-45 et seq., 48:3-87, 48:3-98.1).
[68] Exec. Order No. 28 (May 23, 2018), https://www.nj.gov/infobank/eo/056murphy/pdf/EO-28.pdf.
[69] *2019 New Jersey Energy Master Plan: Pathway to 2050,* https://www.nj.gov/emp/, at 190-91.
[70] *Id.* at 191.

As part of its investigatory process, the BPU commissioned an independent analysis of rate impacts to quantify the impact of the Energy Master Plan on customers' energy costs.[71] In August, the BPU voted to accept the resulting report, explaining that the analysis therein will help the BPU fulfill its role "to ensure policies implemented are fair to ratepayers and to identify ways to mitigate the impact of energy industry changes, particularly on low-income customers."[72]

In February of 2019, the BPU directed staff to initiate a stakeholder process to explore the issue of whether there is sufficient capacity to deliver natural gas to meet consumer needs.[73] After receiving conflicting reports from the utilities and environmental groups, the BPU hired an independent consultant to compare the results of the reports and to determine if New Jersey has adequate gas capacity through 2030.[74] In so doing, the BPU recognized the need to determine "how evolving environmental concerns may drive changes in the way natural gas is transported and used in New Jersey."[75] In June of 2022, the BPU accepted the resulting report's findings, which determined that there is sufficient capacity and which "support the [BPU]'s aggressive policy approach to reduce the State's overall reliance on fossil fuels, and achieve Governor Murphy's goal of 100 percent clean energy by 2050."[76]

On the basis of these findings, the BPU, together with the Division of the Rate Counsel, subsequently intervened in a FERC proceeding regarding the CPCN application for a gas pipeline expansion.[77] Seeking to lodge the report as evidence, the BPU objected to the utility's claim that the pipeline expansion is necessary to serve customer demand, arguing instead that the expansion would burden residents with "unneeded natural gas capacity."[78] Although FERC recently granted the CPCN, finding that "the weight of the record supports the need for the … project,"[79] the BPU's efforts nonetheless provide an example of creative, affirmative advocacy in the public interest and the value of long-term planning.

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[71] Sanem Sergici et al., *New Jersey Energy Master Plan Ratepayer Impact Study* (Aug. 2022).
[72] NJ BPU, *New Jersey Board of Public Utilities Accepts Final Energy Master Plan Ratepayer Impact Study* (August 17, 2022), https://www.nj.gov/bpu/newsroom/2022/approved/20220817.html.
[73] *2-27-19M, Decision and Order*, Docket No. GO17121241 (February 27, 2019).
[74] *5-20-20-9A, Order Soliciting an Independent Consultant*, Docket No. GO19070846.
[75] *Id.* at 4.
[76] *6-29-22-A, Order Accepting Report*, Docket No. GO19070846 (June 29, 2022).
[77] *Motion to Intervene Out of Time and to Lodge of the New Jersey Parties*, FERC Docket No. CP21-94 (July 11, 2022).
[78] *Id.* at 2.
[79] *Order Issuing Certificate and Approving Abandonment*, Docket No. CP21-94-000, 182 FERC ¶ 61,006 (Jan. 11, 2023), at 17.

7. New York

In 2020, the New York PSC also began proceedings to bring long-term gas planning in line with the state's GHG reduction goals.[80] After several gas utilities cited insufficient capacity when instituting moratoria on new gas service connections, the PSC determined a need for gas utilities to "adopt improved planning and operational practices that enable them to meet current customer needs and expectations in a transparent and equitable way while minimizing infrastructure investments and maintaining safe and reliable service."[81]

In addition to addressing potential constraints on supply, the PSC acknowledged that "planning must [also] be conducted in a manner consistent with the recently enacted Climate Leadership and Community Protection Act."[82] That law requires the state to reduce GHG emissions from all anthropogenic sources 100 percent over 1990 levels by 2050, with an incremental target of at least a 40 percent reduction in GHG emissions levels by 2030.[83] The law also requires the PSC to establish a program to decarbonize the electric sector, with targets of 70 percent of the state's electricity deriving from renewable energy by 2030 and 100 percent carbon-free energy by 2040.[84] As in Maryland, the law further directed state agencies, including the PSC, to consider GHG emissions and limits in permitting, licensing, contracting, and other approvals and decisions.[85]

In a March 2020 order instituting long-term planning proceedings, the PSC directed gas utilities to file supply and demand analyses and directed PSC staff to submit a proposal to modernize the gas system planning process.[86] In February of 2021, the PSC published staff's proposal and invited stakeholder engagement through public hearings and comment; and in May of 2022, the PSC adopted the proposed plan with modifications.[87] Among other things, the adopted proposal requires that utilities file long-term plans every three years and lays out various substantive requirements for these filings. The plan also requires the utilities to file interim annual updates; calls for stakeholder participation at multiple stages; and directs staff to hire, and the utilities to pay for, an independent consulting firm to review each utility's long-term gas plans. Additionally, the plan identifies next steps for dealing with issues like the avoided cost of gas by establishing a working group, and depreciation by ordering the gas companies to prepare a study "that examines both the structure of accelerated depreciation and its

[80] *Order Instituting Proceeding*, Case No. 20-G-0131 (Mar. 19, 2020).
[81] *Id.* at 2-3.
[82] *Id.* at 3.
[83] Climate Leadership and Community Protection Act, 2019 N.Y. Laws Ch. 106, § 1 (July 18, 2019).
[84] *Id.* at §4 (codified at NY Pub. Serv. Law § 66-p(2)).
[85] *Id.* at §§ 2 and 7(2) (codified at Envtl. Conserv. Law § 75-0103).
[86] *Order Instituting Proceeding*, Case No. 20-G-0131 (Mar. 19, 2020).
[87] *Order Adopting Proposal*, Case No. 20-G-0131 (May 12, 2022), at 17-18.

potential impact on customers" with the goal to "inform future discussions of how best to recover the costs of assets and reduce potential."[88] The gas companies recently filed the required depreciation studies, and due dates for long-term plans are staggered over the next three years, with the first utility's filing due December 15, 2022.[89]

8. Rhode Island

In 2020, Rhode Island established through executive order a goal to meet 100 percent of the state's electricity demand with renewable energy resources by 2030.[90] In 2021, the state passed the Act on Climate, which accelerated existing economy-wide GHG reduction targets to net zero by 2050 and updated the statutory duties of state agencies to obligate each agency to address "the impacts on climate change … in the exercise of its existing authority."[91]

In light of the new legislation, the Rhode Island PUC opened a docket in June of 2022 to investigate the future of the regulated gas distribution business with the stated purpose "to examine the extent to which the requirements of the Act impact the conduct, regulation, ratemaking, and the future of gas supply and gas distribution within Rhode Island."[92] The PUC began the proceeding by seeking public comment on the proposed scope of the docket, in which it anticipated exploring the two primary alternatives for reducing emissions associated with gas consumption: (1) "creat[ing] a scalable and sustainable market for low- and no-carbon natural gas;" and (2) "transition[ing] customers from the gas system to alternative fuels with clearer pathways for meeting the mandated targets (such as electricity)."[93] The public comment period ended in October 2022, and the PUC recently adopted staff's proposed scope, dividing the proceeding into three phases—policy planning, technical analysis, and policy development—and laying out a series of questions to be incorporated into each phase.[94]

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[88] *Id.* at 61-62.
[89] *Id.* at 65.
[90] Exec. Order 20-01 (2020).
[91] 2021 Act on Climate, 2021 R.I. Pub. Laws Ch. 002 (codified at R.I. Gen Laws § 42-6.2 et seq.)
[92] *Notice of Commencement of Docket*, Docket No. 22-01-NG (June 9, 2022).
[93] *Draft Staff Recommendation for Public Comment*, Docket No. 22-01-NG (Aug. 31, 2022), at 2.
[94] *Proceeding Scope*, Docket No. 22-01-NG (Jan. 3, 2023).

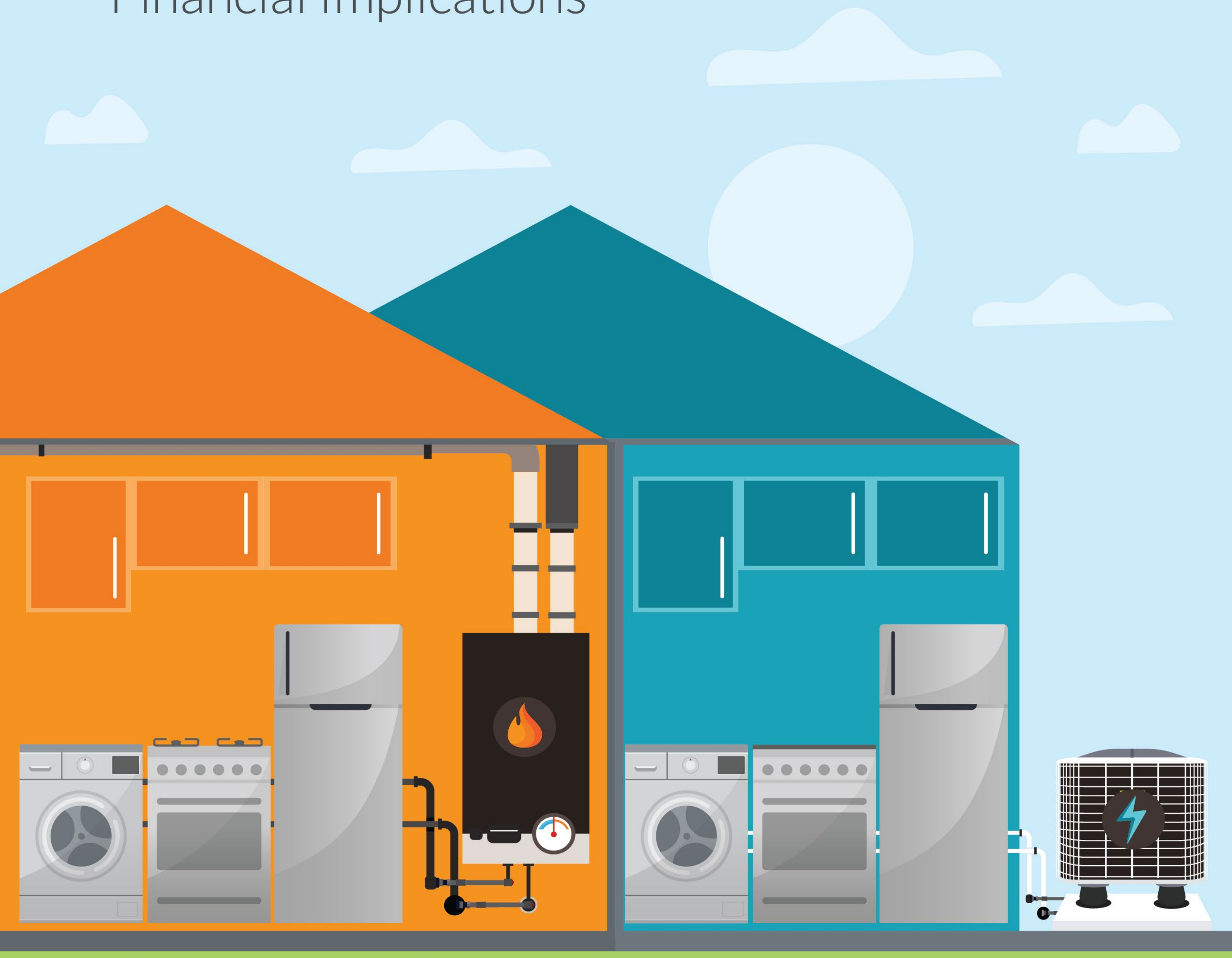
Appendix D

OPC CLIMATE POLICY REPORT

OPC
OFFICE OF PEOPLE'S COUNSEL
State of Maryland

Climate Policy for Maryland's Gas Utilities

Financial Implications



November 2022

DEAR READERS

The most promising path to transforming Maryland's homes and apartments to meet the State's climate goals involves transitioning to electric heating and cooling systems and appliances. This point is not seriously disputed.

What remains at issue for a decarbonized future is the role of the gas utilities' distribution infrastructure and gas itself. As our recent report, Maryland Gas Utility Spending: Projections and Analysis, shows, despite the State's electrification goals, Maryland's gas utilities are on a business-as-usual path, spending tens of billions of dollars on their delivery systems. Gas utilities hope to recover the costs of this spending over many future decades through higher customer rates. Yet these investments are being made in a declining market—inevitably, the number of gas customers and gas sales will decline with electrification. In fact, electrification already is slowly and steadily eating into gas's market share. Residential customers have been turning more and more to electricity for home heating for more than a decade. These declines in gas use will only accelerate in coming years as federal and State policies favoring electrification take effect.

This dynamic of decreasing gas sales and escalating rates raises a fundamental question: Should Maryland's gas utilities continue to invest heavily in gas distribution infrastructure given the declining market?

How this important question is resolved has significant implications for utility customers in the near and long term. The answer determines whether billions of customer dollars will go toward retaining and enhancing the gas distribution infrastructure or whether those dollars can be used to fund any costs associated with electrification or otherwise reduce customer burdens and help Maryland's economy.

Should Maryland's gas utilities continue to invest heavily in gas distribution infrastructure given the declining market?

To better understand the scale of the problem, our office engaged a consultant, Synapse Energy Economics, to evaluate what happens to residential utility rates under the current regulatory model and utility spending trajectory as gas sales decline. The results—described in this report—are telling: Replacing fossil gas with lower carbon alternatives causes the rates of the State's largest gas utility, Baltimore Gas & Electric, to increase two to three times 2021 levels by 2035 and seven to 11 times 2021 levels by 2050, with similar ranges of rate increases for Maryland's two other large gas utilities. Such rates are not sustainable. As rates increase to these levels, the resulting high bills will lead many customers—likely most all customers who have options—to leave the gas system, leaving behind customers without alternatives; those remaining gas customers will be unable to afford continued gas service.

No matter the path forward, electrification holds major consequences for gas utilities and their customers. The potential consequences of business-as-usual spending—tens of billions of stranded

Electrification holds major consequences for gas utilities and their customers.

gas infrastructure assets—has huge implications for the State. Who will bear the consequences of the uneconomic investments? Shareholders? Electricity customers? Taxpayers? Indeed, a recent BGE report acknowledges the unsustainability of maintaining its gas distribution system, foreshadowing that it may seek subsidies for its gas business through "transfer payments from the company's electric business."

Similar to our October 2022 report on gas utility business-as-usual capital spending, our estimates are generally conservative. For the price of fossil gas, the report uses prices ranging from \$2.94/MMBtu to \$4.05/MMBtu, based on U.S. Energy Information Administration's Annual Energy Outlook 2022 Henry Hub natural gas spot price projections (in 2020 dollars). These prices are well below the EIA's September 2022 price of \$7.88/MMBtu. For alternative fuel prices, we use a low-price scenario based on a study prepared for Washington Gas Light, and for the high-price scenario we use estimates from E3's 2021 study for the Maryland Commission on Climate Change.

We hope this report helps educate stakeholders and policymakers on the significance of unmitigated gas utility spending for Maryland's gas utility customers as the State electrifies and initiates policies to meet its greenhouse gas reduction goals, with corresponding reductions in gas utility customer base and gas sales.

David S. Lapp
People's Counsel

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SECTION 1

INTRODUCTION

The Maryland Office of People's Counsel (OPC) asked Synapse Energy Economics, Inc. (Synapse) to analyze the gas rates likely to materialize as more Marylanders switch from fossil-fuel-fired building furnaces and appliances to electric ones as part of the effort to meet the State's greenhouse gas (GHG) reduction targets.

Released in 2021, the Maryland Department of Environment's *2030 Greenhouse Gas Emissions Reduction Act (GGRA) Plan* recommends reducing emissions from buildings using energy efficiency and by electrifying building heating systems. Under this plan, the Mitigation Working Group (MWG) of the Maryland Commission on Climate Change (MCCC) developed and issued the *Building Energy Transition Plan*.[1] To inform this plan, Energy + Environmental Economics (E3) analyzed scenarios for achieving reductions in emissions to near net-zero levels for Maryland's residential and commercial buildings by 2045. In total, E3 modeled four scenarios, including the *MWG Policy Scenario*, which was found both to be the lowest-cost scenario and to reduce residential and commercial building emissions by 95 percent. This scenario reflects four core concepts and objectives, including: ensuring an equitable and just transition; shifting to fossil-free space and water heating for new construction; replacing almost all fossil heating systems in homes with heat pumps by 2045; and implementing an emissions standard that provides commercial buildings compliance alternatives.[2]

In 2022, the Maryland State House and Senate passed the *Climate Solutions Now Act*, which requires the State to reduce GHG emissions by 60 percent from a 2006 baseline by 2031 and to achieve net-zero GHG emissions by 2045.[3] On April 8, 2022, Governor Hogan released a letter stating that he would allow the bill to pass without his signature.[4]

To better understand the potential effects of the MCCC Mitigation Working Group's *MWG Policy*

The **MWG Policy Scenario** was found to be the lowest-cost scenario and to reduce residential and commercial building emissions by 95 percent.

1 Maryland Commission on Climate Change. *Building Energy Transition Plan: A Roadmap for Decarbonizing the Residential and Commercial Building Sectors in Maryland.* Approved by the Mitigation Work Group on Oct. 13, 2021.

2 Id., p. 4.

3 Maryland Senate Bill 528. "Chapter 38: an Act Concerning Climate Solutions Now Act of 2022." Available at: https://mgaleg.maryland.gov/2022RS/Chapters_noln/CH_38_sb0528e.pdf.

4 Governor Larry Hogan. April 8, 2022. *Letter from Governor Hogan to State Senate President Ferguson and State House Speaker Jones.* Available at: https://governor.maryland.gov/wp-content/uploads/2022/04/SB-528-CSNA-SB-566-Investment-Climate-Risk-EWS-Letter.pdf.

To achieve net zero GHG emissions by 2045, the vast majority of **buildings will have to either fully electrify their loads or use alternative gaseous fuels for any gas needs**, including backup heating.

Scenario, we modeled the progress of Maryland's electrification to project GHG emissions, trends in gas consumption, and space heating type and space heating equipment sales. Synapse then used these projections to analyze the financial implications of Maryland's climate goals for gas utilities in the State through 2050. Our analysis focuses on the residential sector, consistent with OPC's statutory mission.

To achieve net zero GHG emissions by 2045, the vast majority of buildings will have to either fully electrify their loads or use alternative gaseous fuels[5] for any gas needs, including backup heating. Buildings are relatively low-cost to electrify with commercially available technologies. On the other hand, the most likely candidates for alternative gaseous fuels pose issues related to cost, availability, emissions, safety, and energy use during production. However, certain end-uses would be far more expensive to electrify or have no viable electric alternatives. Given these considerations, it is important to consider how alternative gaseous fuels should be used.

If alternative gaseous fuels are used for building end-uses, the cost of the commodity will increase, and that additional cost will be reflected in customers' bills. Given the availability of cost-competitive electric alternatives, increased gas costs will drive customers off the gas system and decrease gas sales. At the same time, the utilities' investments in pipeline infrastructure, documented in OPC's recent report, Maryland Gas Utility Spending: Projections and Analysis, will also increase gas customers' bills. With more customers leaving the gas system due to electrification, these higher gas commodity and infrastructure costs will have to be recovered through fewer sales. This will mean higher rates for those remaining customers, which will further drive customers off the gas system and increase the risk that the utility will have stranded assets.

In the remainder of this document, we provide context and describe our findings. Section 2 describes how, under traditional ratemaking, gas companies will be affected as customers migrate away from gas use with increasing electrification of their end-uses. In Section 3, we describe technologies available for decarbonizing buildings. In Section 4, we describe our methodology for analyzing decarbonization trajectories and gas utility financials as sales decline. Appendix A features a list of definitions and abbreviations. Appendix B provides figures for the commercial sector.

Given the availability of cost-competitive electric alternatives, **increased gas costs will drive customers off the gas system and decrease gas sales**.

5 Here we assume that Alternative Gaseous Fuels reduce GHG emissions. However, as explained below, recent studies suggest otherwise.

SECTION 2

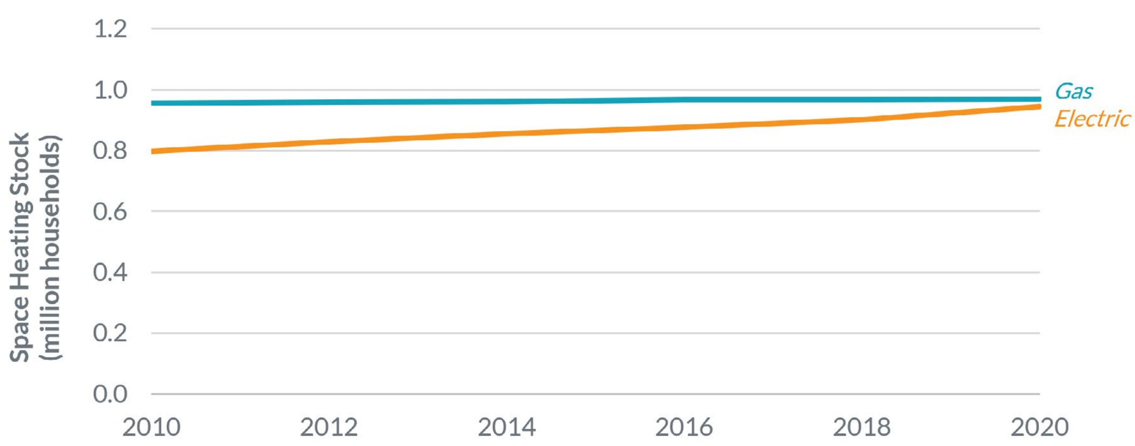
ELECTRIFICATION'S IMPACTS ON GAS RATES

Basic ratemaking principles explain how electrification (the process of switching fossil-fuel-based appliances and other energy end-uses over to electric ones) will affect gas companies by causing customers to migrate away from gas use. The traditional ratemaking model allows utilities to invest in and earn a return on assets such as gas mains and service lines. Utilities recover and earn a return on their investment, typically over the asset's useful lifetime, by including the costs of their investments and the returns on them in the rates they charge customers. This traditional utility business model is designed to ensure utilities can attract shareholders who will put up the money for the investments in exchange for a fair return of—and on—the utility's investments. Without such investments, the thinking goes, utilities would not be able to ensure reliability or meet customers' needs. This model works reasonably well when sales increase over time, but it leads to higher rates when sales are decreasing. Whether occurring as a result of market trends or policy intervention, building electrification will result in declines in gas utility sales, holding all else equal.

Electric heating stock has been increasing for years now, while gas heating stock has stagnated.

Figure 1 shows electric heating stock (mostly heat pumps) has been increasing for years now, while gas heating stock has stagnated. Data from the American Community Survey show that this trend of electrification is occurring across the country. It is notable that

Figure 1. Gas and Electric Space Heating Stock in Maryland Households, 2010-2020



Source: US Census Bureau: American Community Survey. Table DP04: Selected Housing Characteristics for Maryland, 5-year Estimates. June 2, 2022. Available at: https://data.census.gov/cedsci/table?q=DP04&g=0400000US24&tid=ACSDP5Y2020.DP04

this trend toward heating buildings with electricity rather than gas is occurring without significant policy initiatives at the State or local level. While federal and State electrification policies are being discussed (and recently adopted as is the case of the recently enacted *Inflation Reduction Act*, for example), their effects have largely yet to be realized. These policy efforts can be expected to accelerate electrification.

This trend toward heating buildings with electricity rather than gas is occurring **without significant policy initiatives at the State or local level**.

This electrification trend means fewer gas sales. If gas sales decline faster than utilities' asset bases depreciate and faster than the utilities can lower their operating and maintenance costs, gas utilities will seek approval for increasing gas rates to recover the capital invested over fewer unit sales. In turn, higher gas rates are likely to spur more customers to electrify their gas end-uses (furnaces and appliances). As this process goes on, those with the means to electrify—i.e., those who can afford the upfront costs of changing their gas appliances to electric ones and can modify their buildings to accommodate the switch—will do so first. Without changes to regulatory practices or direct assistance, those without access to capital (e.g., low- and moderate-income customers) or the ability to make changes to their dwellings (e.g., renters) will be left on an increasingly costly gas system. Rate escalation will likely hit these groups the hardest.

SECTION 3

TECHNOLOGIES THAT SUPPORT DECARBONIZATION

Achieving net zero by 2045 means that buildings will have to either fully electrify their energy loads or use alternative gaseous fuels for any gas needs, including backup heating. This section discusses key considerations about the available building decarbonization technologies to provide context for the rate analysis in Section 4.

The total cost of installing heat pumps in residential new construction is much less than the cost of installing fossil gas equipment for heat plus central air conditioning (AC) for cooling.

3.1. Electric Space and Water Heating

Heat pumps. Heat pumps provide both energy-efficient cooling and heating. The total cost of installing heat pumps in residential new construction is much less than the cost of installing fossil gas equipment for heat plus central air conditioning (AC) for cooling. For retrofitting an existing building, the cost of installing heat pumps is similar to or less than the combined installed cost of the furnace and central AC. A study by the Lawrence Berkeley National Laboratory (LBNL) found that, on average nationally, a new gas furnace and AC have a combined installed cost of almost $11,000 for residential retrofits. In contrast, the installed cost of heat pumps is substantially less, at just over $8,000.[6] In the absence of extreme price volatility, operating costs, including fuel, are similar for these options.[7] In addition to cheaper up-front costs, heat pumps serve as both the heating and cooling device for a home, requiring a household to only maintain one system. Comparatively, a gas furnace cannot be used for home cooling and requires an additional system for air conditioning.[8]

Electrification will gradually advance as current heating stock reaches the end of its useful life and is increasingly replaced with heat pumps. Moreover, since almost 50 percent of residential buildings in

6 Less, B. D., et al. 2021. *The Cost of Decarbonization and Energy Upgrade Retrofits for US Homes*. Lawrence Berkeley National Laboratory. Available at: https://escholarship.org/uc/item/0818n68p.

7 Energy + Environmental Economics. "Maryland Building Decarbonization Study: Final Report." October 20, 2021.

8 For commercial heating and cooling systems, retrofit costs are harder to compare than for residential ones, because costs vary by building type and data are relatively sparse for the variety of building types in use for commercial applications. Some studies suggest that installed costs for heat pumps are comparable to the cost of gas heating and separate electric AC systems for commercial buildings. (Group 14 Engineering, *Electrification of Commercial and Residential Buildings*, (2020) available at: https://bit.ly/3skNqAp.) For small commercial customers, E3's study for Maryland found that all-electric new construction is cheaper than mixed-fuel new construction due to lower capital and operating costs. (Energy + Environmental Economics. "Maryland Building Decarbonization Study: Final Report." October 20, 2021.)

Maryland are already heated primarily with an electric heating unit (either electric resistance or heat pumps), electrification is already underway in the State.[9]

Hot water heaters. The total equipment and installation costs of electric heat pump water heater (HPWH) retrofits are generally much higher than those of gas storage water heaters.[10] As with space heating, the operating costs of electric and gas appliances are generally similar. Considering fuel costs, electric rate structures such as time-of-use rates can give electric appliances and equipment an edge over gas systems. (Customers billed under a time-of-use rate generally pay more during peak energy-usage hours than during off-peak hours, such as late at night or early in the morning.)

Panel upgrades. Electrification may require upgrades to electrical circuits and panels to accommodate additional load. The cost of upgrading the electrical panel typically ranges from about $500 to $2,000 for most homes, while the costs could be more than $3,000 for others.[11] For some households, these costs can be mitigated. Newer buildings generally have high electrical capacity and thus may not need upgrades. Some customers may upgrade their electrical panels to support electric vehicles and be ready for building electrification measures without additional upgrades. Finally, these costs also can be avoided in the future by using low-amp appliances that are currently in development.

Inflation Reduction Act. The recently enacted federal Inflation Reduction Act (IRA) could substantially reduce the costs of electrification through tax credits. Homeowners can receive a tax credit of up to $2,000 per year to install heat pumps or electric water heaters and up to $600 per year for electrical panel upgrades.[12] The IRA also authorizes rebates for qualifying households for electrification and efficiency measures, including heat pumps, heat pump water heaters, electric stoves, heat pump clothes dryers, circuit panels, wiring, and insulation and air sealing.

3.2. Heat Pumps with Fuel Backup (Hybrid Systems)

Heat pumps can be used in concert with fossil fuel backup or supplemental heating systems. Such backup systems could reduce pressure on the electric system to accommodate higher loads from electrification. However, in a moderate climate like Maryland (with only around 4,000 heating degree days annually)[13] fuel backup is unnecessary. ACEEE found that households in the State would not need fuel backups when using cold-climate heat pumps, which are advanced heat pump systems that provide

Fuel backup systems are unnecessary, and deploying them is costly for consumers.

9 U.S. Energy Information Administration. Residential Energy Consumption Survey: 2020 RECS Survey Data. Available at https://www.eia.gov/consumption/residential/data/2020/index.php?view=state&src=%E2%80%B9%20Consumption%20%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20(RECS)-f2, accessed October 20, 2022.

10 Less, B. D., et al. 2021. *The Cost of Decarbonization and Energy Upgrade Retrofits for US Homes.* Lawrence Berkeley National Laboratory. Available at: https://escholarship.org/uc/item/0818n68p.

11 HomeAdvisor. July 6, 2022. "Cost to Upgrade an Electrical Panel." Available at: https://www.homeadvisor.com/cost/electrical/upgrade-an-electrical-panel/.

12 Inflation Reduction Act of 2022, §13301. Available at: https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

13 Heating degree days measure how cold the outdoor temperature is relative to a standard temperature, generally 65° Fahrenheit (F), over a period of time. For example, a day with a mean temperature of 40°F would have 25 HDD. (U.S. Energy Information Administration, Units and calculators explained: Degree days. Available at: https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php.) Over the course of a year, Maryland has approximately 4,000 HDD. (Nadel, S. and L. Fadali. 2022. *Analysis of Electric and Gas Decarbonization Options for Homes and Apartments.* Washington, DC. ACEEE. Available at: https://www.aceee.org/sites/default/files/pdfs/b2205.pdf.)

heat down to 5 degrees Fahrenheit or lower.[14] Fuel backup systems are unnecessary, and deploying them is costly for consumers because the gas utilities would need to upgrade old parts of the distribution system and maintain the entire system for use during just a small portion of the year.

3.3. Alternative Gaseous Fuels

Considering that some uses of fossil gas do not currently have electric alternatives, replacing fossil fuel gas with lower carbon alternatives will play an important role for the State's achievement of its climate goals. The most likely alternative gaseous fuels that have potential for replacing fossil gas are biomethane, recovered methane, hydrogen, and synthetic natural gas or synthetic methane.

3.3.1. Biomethane and recovered methane

Recovered methane is methane captured from gas distribution system leaks or other sources. *Biomethane* (also called renewable natural gas, or RNG) is a mixture of carbon dioxide and hydrocarbons released from the decomposition of organic matter. Biomethane must be processed to remove impurities, liquid water, and hydrocarbons, and to attain acceptable heat content.[15] Processing increases costs, consumes energy, and requires investment in processing facilities.

Both biomethane and recovered methane pose collection, processing, and transportation challenges that raise their costs. It may be more economical to use these fuels for some other purpose, in a less-processed form and closer to their sources, rather than using them in distant buildings to replace fossil gas consumption.

Both biomethane and recovered methane pose **collection, processing, and transportation challenges that raise their costs.**

Both biomethane and recovered methane supplies are currently limited and likely to remain constrained well into the future. According to the consulting firm ICF International's 2019 report for the American Gas Foundation, constraints in available biomass feedstocks severely limit biomethane that is potentially carbon-negative, which includes anaerobic digestion of food waste, dairy, and swine manure. (Other feedstocks—gasification of agricultural and forest residue, municipal solid waste, and energy crops—have fewer supply constraints but unfavorable carbon footprints.) The 2019 ICF International report estimates that supplies of the feedstocks that are likely to be carbon negative from Maryland sources will amount to just 5.766 tBtu in 2040 in a high-potential scenario.[16] Relative to current residential gas consumption in Maryland—80.418 tBtu for the residential sector alone in 2020—carbon negative biomethane could displace only a small portion of current gas sales in the State, even assuming

14 One field study in Vermont observed that cold climate heat pumps operated under -20° F at above 1 coefficient of performance (COP) but with reduced capacity. (Walczyk, J. 2017. Evaluation of Cold Climate Heat Pumps in Vermont. Prepared by The Cadmus Group, LLC for the Vermont Public Service Department. Available at: https://publicservice.vermont.gov/sites/dps/files/documents/Energy_Efficiency/Reports/Evaluation%20of%20Cold%20Climate%20Heat%20Pumps%20in%20Vermont.pdf.) *See also*, Nadel, S. and L. Fadali. 2022. *Analysis of Electric and Gas Decarbonization Options for Homes and Apartments.* Washington, DC. ACEEE. Available at: https://www.aceee.org/sites/default/files/pdfs/b2205.pdf.

15 Gas quality specifications may vary by pipeline. (Thomson Reuters Practical Law: Pipeline Quality Natural Gas (US). Available at: https://content.next.westlaw.com/practical-law/document/Iee1c892db6ea11eabea4f0dc9fb69570/pipeline-quality-natural-gas?viewType=FullText&originationContext=document&transitionType=DocumentItem&ppcid=b60bf2510cb649d7a374f9f88d3199f5&contextData=(sc.DocLink)&firstPage=true, accessed October 18, 2022.)

16 ICF International. 2019. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment. Prepared for the American Gas Foundation.* Available at https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

Carbon negative biomethane could displace only a **small portion** of current gas sales in the State.

declining gas sales in future years.[17] There also will be competition for the limited biomethane supplies as other states seek to decarbonize their economies.[18]

Because methane is a potent GHG, leaks undercut overall climate efforts. A GHG emissions mitigation strategy that integrates these fuels into the existing distribution system for widespread use should account for fugitive emissions during transport.

Methane leakage also poses safety concerns. Local fire departments in the United States respond to 4,200 home fires caused by ignition of fossil gas per year, most of which involve some type of leak. Each year on average, these fires result in $54 million in direct property damage, 140 civilian injuries, and 40 civilian deaths.[19]

Like fossil gas, in-home use of biomethane and recovered methane poses health and safety concerns due to combustion and leaks.[20] Indoor nitrogen oxide (NO_x) emissions contribute to increased respiratory symptoms and asthma attacks.[21]

3.3.2. Hydrogen

There are different methods of producing hydrogen that impact its carbon footprint. "Gray" hydrogen is produced from fossil gas. As the most common hydrogen production method, gray hydrogen accounts for 6 percent of fossil gas consumption worldwide.[22] "Blue" hydrogen is produced using the same process, but the associated GHG emissions are captured and stored. With both gray and blue hydrogen, emissions result from fossil gas extraction, processing, and use. As a result, gray and blue hydrogen do not provide emissions reductions relative to direct combustion of fossil gas, diesel, or coal for generating heat, as shown in Figure 2.

Gray and blue hydrogen do not provide emissions reductions relative to direct combustion of fossil gas, diesel, or coal for generating heat.

17 Maryland Department of the Environment. 2020. "GHG Emission Inventory." Available at: https://mde.maryland.gov/programs/air/climatechange/pages/greenhousegasinventory.aspx.

18 For example, New York will likely dramatically reduce gas consumption in compliance with its Climate Leadership and Community Protection Act, with likely high demands for RNG for difficult-to-electrify end uses. Current gas consumption in New York, excluding gas for electric power generation, is about 950 Tbtu—far outstripping a recent study's projected statewide potential RNG supply of 47 tBtu/yr. and 147 tBtu/yr. (New York State Energy Research and Development Authority (NYSERDA). 2021. "Potential of Renewable Natural Gas in New York State," NYSERDA Report Number 21-34. Prepared by ICF Resources, L.L.C., Fairfax, VA 22031. nyserda.ny.gov/publications.)

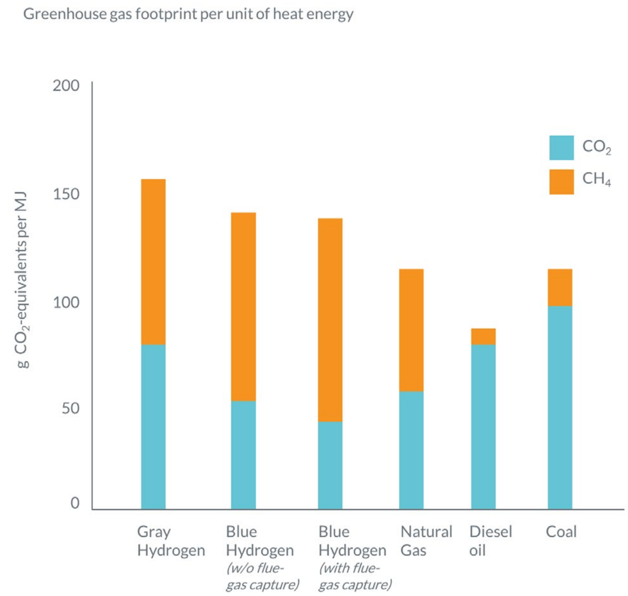
19 The National Fire Protection Association. 2018. "Natural Gas and Propane Fires, Explosions and Leaks: Estimates and Incident Descriptions." Available at https://bit.ly/3vCjxLw.

20 California Energy Commission 2020. *Final Project Report: Air Quality Implications of Using Biogas to Replace Natural Gas in California.* Available at: https://www.energy.ca.gov/sites/default/files/2021-05/CEC-500-2020-034.pdf.

21 Seals, B., Krasner, A. 2020. *Health Effects from Gas Stove Pollution.* Rocky Mountain Institute, Physicians for Social Responsibility, Mothers Out Front, and Sierra Club. Available at: https://rmi.org/insight/gas-stoves-pollution-health/.

22 Howarth, R., Jacobson, M. 2021. "How green is blue hydrogen?" *Energy Science & Engineering*: 12. August. Available at https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.956.

Figure 2. Comparison of GHG emissions intensity of gray and blue hydrogen with direct consumption of gas, oil, and coal



Note: Assumes a methane leakage rate of 3.5 percent.

Source: "Greenhouse gas footprint per unit of heat energy" © by Howarth, R., Jacobson, M. 2021. Retrieved from https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.956. Used under Creative Commons Attribution 4.0 International (CC BY 4.0)-Modified to be black and white, remove title, and remove 200 g CO2-equivalents per MJ axis label.

"Green" hydrogen is produced using water as the source of the hydrogen and a carbon-free resource to convert the water to hydrogen. Green hydrogen is not currently cost-competitive with gray hydrogen, although the relative costs may decline as renewable energy costs continue to decrease or policies are enacted that raise the price of fossil fuels.[23]

Hydrogen poses **difficulties for integration** into existing gas infrastructure.

Hydrogen poses difficulties for integration into existing gas infrastructure. Hydrogen can be blended into the gas in the existing pipeline network in small quantities. While some literature has suggested that it may be safe to blend hydrogen into the existing infrastructure up to 20 percent by volume (equivalent to 7 percent by energy content), analysis for the California Public Utilities Commission indicates that only up to 5 percent by volume can be blended in safely.[24] Even if blending hydrogen up to 20 percent by volume (7 percent by energy content) into the existing gas network is safe, doing so would have a limited impact on offsetting fossil fuel use and the corresponding emissions. Higher concentrations of hydrogen would require replacing much of the existing distribution system, since the heat content of hydrogen is lower than methane (requiring larger pipes to accommodate the same energy content) and since some metals (such as those used for pipes) become brittle when exposed to hydrogen.[25]

Hydrogen cannot be interchanged with methane in today's household gas appliances. Beyond relatively low hydrogen blends, consumers would need to purchase new appliances to burn hydrogen safely. As with fossil gas, hydrogen will leak and thereby have reduced carbon benefits. Finally, hydrogen raises safety concerns because it can ignite more easily than natural gas.[26]

23 Howarth, R., Jacobson, M. 2021.

24 Melaina, M., Antonia, O., Penev, M. 2013. *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*. National Renewable Energy Laboratory Technical Report NREL/TP-5600-51995. Available at: https://www.nrel.gov/docs/fy13osti/51995.pdf. Penchev, M., T. Lim, M. Todd, O. Lever, E. Lever, S. Mathaudhu, A. Martinez-Morales, and A.S.K. Raju. 2022. *Hydrogen Blending Impacts Study Final Report*. Agreement Number: 19NS1662. California Public Utilities Commission. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

25 U.S. Department of Energy. 2022. "Safe Use of Hydrogen." Available at: https://www.energy.gov/eere/fuelcells/safe-use-hydrogen#:~:text=A%20number%20of%20hydrogen's%20properties,in%20case%20of%20a%20leak.

26 For a technical discussion of the issues discussed here, see Livermore, S., "Exploring the potential for domestic hydrogen appliances," *The Engineer* (2018), available at https://bit.ly/3C2vigD.

3.3.3. Synthetic methane

Synthetic methane can be produced with hydrogen (obtained from electrolysis) and carbon dioxide, (captured either from the ambient air or from exhaust streams before it is released into the air). If renewable energy is used for electrolysis, carbon capture, and other processing, the fuel can have a low-carbon footprint but requires large quantities of energy to produce.[27] Similar to fossil gas, synthetic methane will leak from pipes, and there will be costs associated with fixing leaks, replacing leak-prone pipes, or losses of the fuel. Synthetic methane poses safety risks similar to fossil gas, biomethane, and recovered methane. Leaks of synthetic methane can lead to fires. In addition, synthetic methane combustion causes releases of NOx and other harmful air pollutants, which can lead to serious respiratory health impacts.[28]

3.3.4. Observations about Alternative Gaseous Fuels

The discussion above shows that the most likely candidates for alternative gaseous fuels pose challenges related to cost, emissions, safety, and energy use during production. None of the alternatives that would reduce GHG emissions are available now at scale or at a price similar to natural gas.

The most likely candidates for alternative gaseous fuels pose **challenges related to cost, emissions, safety, and energy use during production.**

Finally, competition for alternative gaseous fuels could be fierce, in Maryland and elsewhere. Other economic sectors—transportation, industrial processes, and electric generation—will compete with buildings for low-carbon alternative fuels. Alternative gaseous fuels will be important for certain of these non-building end-uses because they involve activities that are far more expensive to electrify or for which there are no available electric alternatives. In contrast, buildings are relatively low-cost to electrify and can take advantage of commercially available technologies for space and water heating and for other uses. As a policy matter, it may be important to reserve alternative gaseous fuels for activities that cannot easily be electrified.

27 Melaina, M., Antonia, O., Penev, M. 2013. *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues.* National Renewable Energy Laboratory Technical Report NREL/TP-5600-51995. Available at: https://www.nrel.gov/docs/fy13osti/51995.pdf.

28 The NOx that is formed when natural gas, biogas, or SNG is combusted comes primarily from nitrogen and oxygen in the air interacting in the high-heat conditions of combustion. Exposure to NOx pollution can aggravate existing respiratory problems and potentially lead to development of respiratory disease. (NRDC 2020. A Pipe Dream or Climate Solution? The Opportunities and Limits of Biogas and Synthetic Gas to Replace Fossil Gas." Available at https://www.nrdc.org/sites/default/files/pipe-dream-climate-solution-bio-synthetic-gas-ib.pdf.)

SECTION 4

MODELING

To better understand the potential effects of the *MWG Policy Scenario*, we modeled the progress of Maryland's electrification under E3's *MWG Policy Scenario*, which we call "Sector Specific Electrification" (SSE). Using our Building Decarbonization Calculator (BDC), we modeled total GHG emissions, trends in gas consumption, and residential and commercial building stock by space heating type and space heating equipment sales under SSE. The model analyzed the turnover of residential and commercial space and water heating systems across Maryland and calculated the corresponding emissions impacts. Our BDC assumptions are detailed in Section 4.1.1, below.

Synapse then applied its Gas Rate Model (GRM) to the BDC modeling results to assess the financial implications for Maryland's three largest gas utilities through 2050. The GRM uses the utilities' historical data and the BDC modeling results to project SSE's impacts on rate base, revenues, and expenses for each of the utilities: Baltimore Gas and Electric (BGE), Washington Gas Light (WGL), and Columbia Gas of Maryland (Columbia or CMD). We also evaluated the residential customer rate impact of using alternative gaseous fuels to offset increasing portions of remaining gas system emissions, culminating in zero remaining fossil gas by 2045.

The BDC modeling, combined with the GRM results, ultimately sheds light on the *MWG Policy Scenario's* effects on gas utilities. It also assesses the scenario's implications for residential customer rates and the stranding of gas utility investments.

4.1. Building Decarbonization Calculator

4.1.1. Assumptions

The BDC uses Maryland-specific data on existing buildings from the U.S. Census Bureau's *American Community Survey,* along with the U.S. Energy Information Administration's *Residential Energy Consumption Survey* and *Commercial Buildings Energy Consumption Survey,* to develop estimates for the characteristics of Maryland's building space and water heating system stock. To determine the current heat pump market share of new installations, we analyzed recent annual increases in the number of homes heated primarily with electricity as reported by the *American Community Survey.*[29]

Residential building electrification target: Consistent with the *MWG Policy Scenario*, under our SSE scenario heat pumps are the sole source of heating in over 95 percent of residential buildings by 2050. To achieve this, we assume that all new construction is all-electric by the late 2020s. In existing buildings, this level of electrification is achieved through steady increases in

29 American Community Survey. 2019. *Table B25040: House Heating Fuel for Maryland, 5-year Estimates.* Available at: https://data.census.gov/cedsci/table?q=house%20heating%20fuel&tid=ACSDT5Y2020.B25040.

We assumed that gas heating will be phased out as **heating units are replaced at the end of their useful lives**.

heat pumps' share of the Maryland market. By 2030, over 95 percent of households that are replacing space heating equipment at the end of the equipment's useful life use heat pumps, increasing to 100 percent by 2035.[30]

Heat pump market share: Based on recent historical data from the *American Community Survey*, we assumed that the number of residential households heating with heat pumps increased by about 8,000 households between 2019 and 2020. We calculated that this level of annual increase implied a heat pump market share (i.e., the percent of space heating equipment sales that are heat pumps) of approximately 10 percent of new heating systems replacing retiring residential fossil fuel systems. We modeled residential heat pump adoption curves starting at these market share values in 2020, and then escalating toward the electrification target over time.[31] While there is no fixed date by which all buildings will be all-electric, the modeling is designed to convert the market to 100 percent heat pumps, such that gas heating will be phased out as heating units are replaced at the end of their useful lives.

Multi-family housing units: Throughout our analysis, we categorized all households in Maryland as being in the residential sector, even though large multifamily residential buildings may require different types of heat pump systems than single-family homes. We measure the sizes of heat pump systems by the number of households they serve. For example, one large heat pump system serving 100 apartments is modeled as 100 individual heat pump systems. Where we were able to break out residential results from total, we present the residential sector here. The results for the commercial sector are provided in Appendix B. Industrial sector gas consumption is not included in this report.

4.1.2. Results

For each year between 2020 and 2050, our modeling shows how SSE impacts the new space and water heating system installations, the total stock of operating space and water heating systems, and the resulting on-site GHG emissions. We discuss these results in the paragraphs below:

- Residential GHG emissions
- Residential gas consumption
- Residential building stock by space heating type and space heating equipment sales

Residential GHG emissions

Figure 3 shows total residential space and water heating emissions. Figure 3 does not account for using low- or zero-carbon gases to reduce emissions. Also, this figure does not include off-site GHG emissions, such as those resulting from the generation of electricity[32] or the upstream methane emissions from

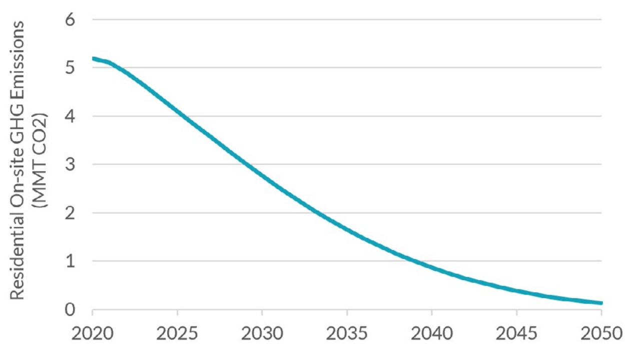
30 In commercial buildings, by 2050, 60 percent of gas-connected buildings switch to heat pumps as the sole source of heating and 40 percent of gas-connected buildings stay on gas for heating. Over 99 percent of all new construction is 100 percent electrified by 2035. Existing buildings with electric resistance heat convert to heat pumps by 2050 and existing buildings with heat pumps continue to use heat pumps.

31 Given that existing commercial buildings would have a harder time switching to heat pumps due to the complexity of their HVAC system configurations, we assumed initial commercial market shares equal to half of the historical residential sales rate. We assumed these market share rates to meet the residential and commercial building electrification targets, described above.

32 While increasing electricity consumption to power heat pumps will lead to some increase in electric generation emissions, that impact is beyond the scope of this report. The emissions increase will be mitigated by Maryland's Renewable Portfolio Standard, which requires 50 percent of electricity to come from renewable resources by 2030, as well as other future policies that may further decarbonize the power sector beyond 2030. Expanded demand-side management and demand response can also reduce electrification's impact on load and emissions.

leaks associated with production, distribution, and transmission of fossil or alternative gaseous fuels.

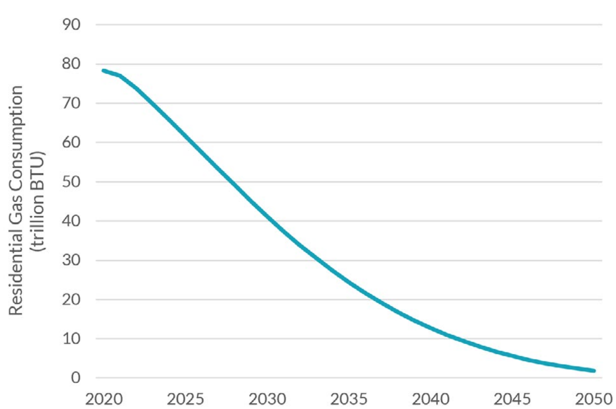
Figure 3. Residential on-site space and water heating GHG emissions, before accounting for use of low- or zero-carbon gas or off-site emissions



Gas consumption

Figure 4 shows SSE's impacts on residential space and water heating gas consumption. The corresponding commercial space and water heating gas consumption chart can be found in Appendix B. To fully decarbonize building energy consumption, remaining gas consumption will need to be displaced with low- and zero-emissions fuels.

Figure 4. Residential consumption of gas for space and water heating



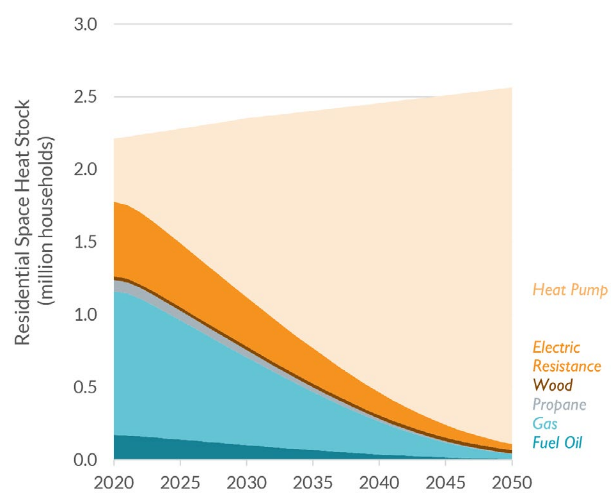
Space heating equipment stock and sales

In this section, we present charts that show the total stock and annual sales of space heating equipment under SSE. We focus on space heating equipment, because it is currently responsible for most on-site emissions from residential buildings.[33] The second largest source of on-site emissions from residential buildings is water heating, which represents a much smaller portion of current total emissions: For residential space and water heating equipment combined, space heating equipment accounts for 74 percent of on-site emissions and water heating equipment accounts for 26 percent of on-site emissions.

Water heating equipment similarly transitions toward heat pump technologies in our analysis but is not separately shown here for simplicity.

Figure 5 shows that SSE results in nearly all buildings, including 96 percent of homes, being fully heated with heat pumps by 2050. Fossil fuel space and water heating is almost entirely eliminated, resulting in the greatest emissions reductions.

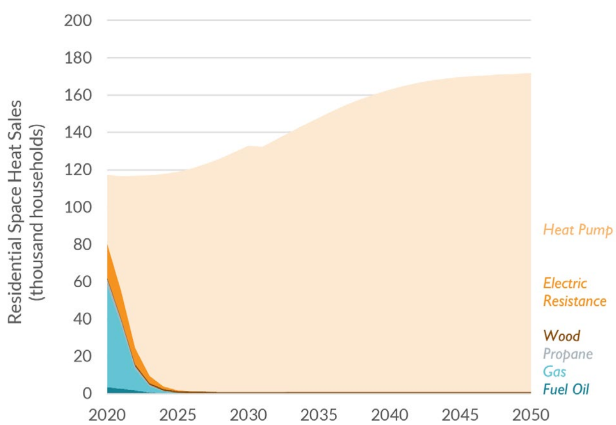
Figure 5. Residential building stock by space heating fuel and technology



33 In 2020, space and water heating equipment were responsible for most fossil gas use from residential buildings. Space and water heating equipment accounted for 91 percent of residential gas consumption, while the remaining 9 percent of gas consumption was attributable to cooking, clothes drying, and other end-uses that were not included in our modeling here. (U.S. Energy Information Administration. 2018. *Residential Energy Consumption Survey*. Available at: https://www.eia.gov/consumption/residential/.)

To achieve this level of electrification, residential space heating equipment sales almost entirely shift to heat pumps by the mid-2020s, as shown in Figure 6.

Figure 6. Residential space heating equipment sales[34]



As Figure 6 shows, gas heating equipment sales drop to near zero under this scenario, allowing for the almost complete removal of the gas system by 2050.[35]

Results for the commercial sector are provided in Appendix B.

4.2. Gas Rate Model

Applying the BDC results, we now model the financial impact on the gas utilities of electrifying the building heating stock.

The GRM allows Synapse to project gas utility rates based on different scenarios for utility investment, sales, and financial models. We use input data from annual utility reports to State regulators, alongside data from the Pipeline and Hazardous Materials Safety Administration[36] (for gas pipeline investment data) and rate cases[37] (such as depreciation and cost-of-service studies) to build a model of the past up to the present. The model tracks utility plant-in-service, depreciation, capital additions and retirements, operations and maintenance, and income taxes. It accounts for capital structure and changes in tax rates.

Looking forward from the present, the model allows us to test scenarios for different levels of investment and customer growth or decline, pipeline replacement programs, early retirements, stranded costs, and changes in depreciation rates. These cases can correspond to electrification, as assumed in the analysis here, or other decarbonization scenarios developed in the BDC. We have developed ways to map changes in customer numbers to changes in miles of pipeline in service and other aspects of capital assets.

The GRM must make assumptions about fuel prices. Here, as described below, we make assumptions for fossil fuel price and for alternative gaseous fuels. For alternative gaseous fuels, we use two fuel cost sensitivities—the Low AGF Price sensitivity and the High AGF Price sensitivity.

The following section details our assumptions for GRM inputs. The assumptions and projections are explained and analyzed in Sections 4.2.1 and 4.2.2, and Section 4.2.3 shows results of the modeling in terms of gas rate base per customer, rates, and bill impacts.

34 The slight decrease in new installations between 2030 and 2031 results from slower expected population growth (and consequently new housing construction) after 2030. (Weldon Cooper Center for Public Service. 2018. Observed and Total Population for the U.S. and the States, 2010-2040. *Demographics Research Group.* Available at: https://demographics.coopercenter.org/national-population-projections.)

35 Apart from replacing gas equipment, heat pumps will replace electric resistance heating stock. Replacing electric resistance heaters with more efficient heat pumps should reduce the electric load from those buildings and partially offset the increased electric load due to replacing the gas heating stock with heat pumps.

36 U.S. Department of Transportation: Pipeline and Hazardous Materials Safety Administration. August 2, 2021. Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data. Available at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

37 Maryland Public Service Commission. 2021. *Case Search.* Available at: https://www.psc.state.md.us/.

4.2.1. Assumptions and Analysis

Alternative Gaseous Fuel Pricing: In the Low AGF Price sensitivity, the price of alternative gaseous fuel from 2021 to 2050 ranges from $14.37/MMBtu to $22.92/MMBtu, based on a 2020 ICF report for AltaGas and WGL (in 2020 dollars).[38] In the High AGF Price sensitivity, the price of alternative gaseous fuel from 2021 to 2050 is $69.03/MMBtu, based on a report by E3 on building decarbonization in Maryland (in 2020 dollars).[39] The price of fossil gas is kept the same in both the Low and High AGF Price sensitivities. From 2021 to 2050, the price of fossil gas ranges from $2.94/MMBtu to $4.05/MMBtu, based on the U.S. Energy Information Administration's *Annual Energy Outlook 2022* Henry Hub natural gas spot price projections (in 2020 dollars).[40]

Assumptions about the climate impact of renewable and low-carbon gases: Synapse modeled the SSE scenario such that no fossil gas remains in the system past 2045 and that remaining gas use is provided by alternative gaseous fuels. Our modeling assumes that renewable and low-carbon gases are emissions-free and that the buildings sector will be responsible for emissions reductions proportionate to its current emissions. With this assumption, BGE, WGL, and Columbia Gas's conversion to all low-carbon gases would support the State's compliance with the *Climate Solutions Now Act*. Recent studies show, however, that alternative gaseous fuels have higher emissions rates than previously assumed. For example, a 2022 analysis by Imperial College London found that leakage rates from RNG may be twice as high as previously thought.[41] Though beyond the scope of our work here, such leakage rates would reduce the benefits associated with low-carbon fuels and make *Climate Solutions Now Act* compliance more challenging.

Infrastructure replacement: We assume that the Maryland Public Service Commission continues to approve each utility's current investment approach, as allowed under PUA § 4-210 (the *Strategic Infrastructure Development and Enhancement*, or STRIDE, law) as though electrification and customer departures are not occurring. Under STRIDE, gas utilities currently run programs to replace leak-prone pipes (generally cast-iron and bare-steel pipes) with plastic pipes. The STRIDE program replaces both *mains* (larger pipes that serve many customers) and *services* (the building-specific pipes that connect the mains to customer buildings). STRIDE permits utilities accelerated recovery of the costs of gas infrastructure replacements through a surcharge on customer bills. The surcharge is capped at $2.00/month on residential bills but is reset with each base rate case, when STRIDE investments are moved into base rates.

Recent studies show that **alternative gaseous fuels have higher emissions rates** than previously assumed.

38 ICF International. April 2020. *Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals*. Available at: https://sustainability.wglholdings.com/wp-content/uploads/Technical-Study-Report-Opportunities-for-Evolving-the-Natural-Gas-Distribution-Business-to-Support-DCs-Climate-Goals-April-2020.pdf. AltaGas is the Canadian parent company of WGL.

39 Clark, T., D. Aas, C. Li, J. de Villier, M. Levine, J. Landsman. October 20, 2021. *Maryland Building Decarbonization Study*. Energy + Environmental Economics. Available at: https://mde.maryland.gov/programs/Air/ClimateChange/MCCC/Documents/MWG_Buildings%20Ad%20Hoc%20Group/E3%20Maryland%20Building%20Decarbonization%20Study%20-%20Final%20Report.pdf at 13 (showing a conservative alternative gaseous fuel price of $70/MMBtu (in 2021$), which we converted into 2020$ to arrive at the $69.03/MMBtu value).

40 U.S. Energy Information Administration. March 2022. *Annual Energy Outlook 2022: Table 13*. Available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2022&region=0-0&cases=ref2022&start=2020&end=2050&f=A&linechart=ref2022-d011222a.31-13-AEO2022&ctype=linechart&sourcekey=0.

41 Imperial College London. 2022. "Biogas and biomethane supply chains leak twice as much methane as first thought." Phys.org. Available at https://phys.org/news/2022-06-biogas-biomethane-chains-leak-methane.html.

The assumption in the SSE scenario that utilities continue under their current investment approach means that the STRIDE program continues as planned and depreciation rates for utility investment continue to be set at today's levels, based on the expected engineering life of assets—as long as 70 years for new plastic pipes, for example. STRIDE cost calculations are imported from analysis by DHInfrastructure for OPC. Although STRIDE investments continue, the GRM scenario assumes that customers are electrifying and departing the system, consistent with the BDC scenario results.

Depreciation: Additionally, Synapse assumed that the utilities do not update their depreciation approach, despite the customer departures. Accordingly, we used recent depreciation studies from each utility to determine their 2020 depreciation rates and used these 2020 values for each specific utility asset from 2021 to 2050 (approximately 100 utility assets per utility).[42]

Capital additions: In the GRM, we calculated capital additions for distribution plant mains, services, meters, meter installations, and house regulators based on net customer additions, pipeline retirement approach, and historical pipe data. All other capital addition line items grow at 2 percent per year. This growth rate corresponds to the 2 percent inflation rate that we used throughout the model.[43]

Operations & Maintenance: We projected operations and maintenance expenses based on the total number of customers, the miles of pipeline, and the number of services for each future year. This projection also used the model-wide inflation rate of 2 percent.

Other costs: We held after-tax return on equity, cost of debt, debt fraction of capital, federal income tax, and state income tax constant at their 2020 levels.

Rate Class Allocations: To determine the rates by class (residential versus commercial and industrial customers), we separated out each utility's revenue requirement based on the proportion of residential customers to commercial and industrial customers and the proportion of residential gas sales to commercial and industrial gas sales. The BDC modeling provided the split between residential and commercial and industrial customers both for customer counts and gas sales. The calculation to determine rates by class also accounts for different drivers of utility revenue requirements. Specifically, some costs (like billing and customer service) scale with the number of customers, while other costs (like maintenance) are more closely related to the miles of mains or number of services. Our methodology is informed by common practice in cost allocation studies.

4.2.2. Customer and Sales Projections

Customers: Using customer projections from the heating stock results of the BDC modeling, we determined that more customers leave the natural gas system than are added to the gas system in each year of the modeling, starting in 2021. Total annual customer additions decrease to zero by 2038 in BGE, by 2037 in WGL, and by 2033 in Columbia. By 2050, the total customers left on each of the three utility systems is just 5 to 7 percent of their total 2020 number of customers.

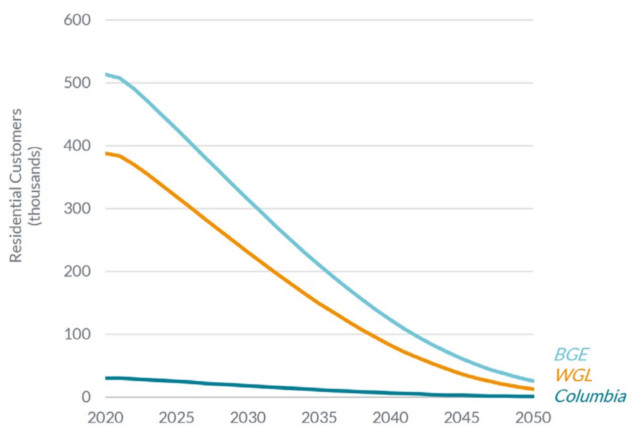
42 DHInfrastructure used total distribution, transmission, and composite non-STRIDE depreciation rates and held the 2022 values constant throughout its analysis. DHInfrastructure did not break out distribution, transmission, and depreciation rate projections by specific utility asset, as Synapse did. The difference between the Synapse and DHInfrastructure depreciation methodologies reflects the difference in granularity needed for each model and the overall projection methodology for each analysis. Relative to DHInfrastructure's analysis, Synapse tracked a greater number of individual data points to allow consideration of alternative futures.

43 In comparison, DHInfrastructure assumed that total non-STRIDE capital expenditures stay constant at their 2022 values and do not increase with inflation. Synapse broke out the non-STRIDE capital expenditure projections by utility asset or utility asset grouping. Synapse further used a separate, more detailed methodology for certain capital additions, preventing us from using just one set rate of change for all capital additions. Since DHInfrastructure was tracking fewer data points, holding the non-STRIDE capital expenditures constant was sufficient to effectively project the results of a status quo approach.

By 2050, the total customers left on each of the three utility systems is just 5 to 7 percent of their total 2020 number of customers.

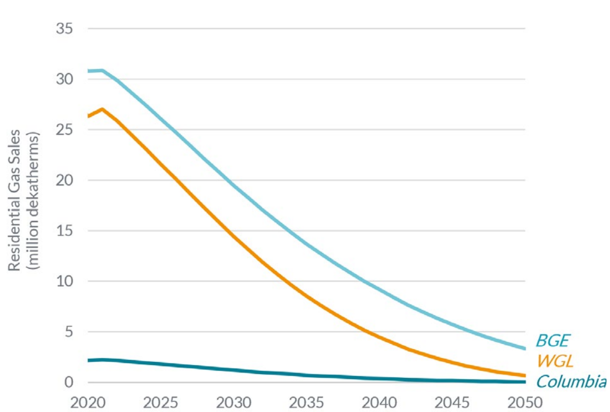
Figure 7 shows detailed residential customer projections by utility.

Figure 7. Residential customers by utility



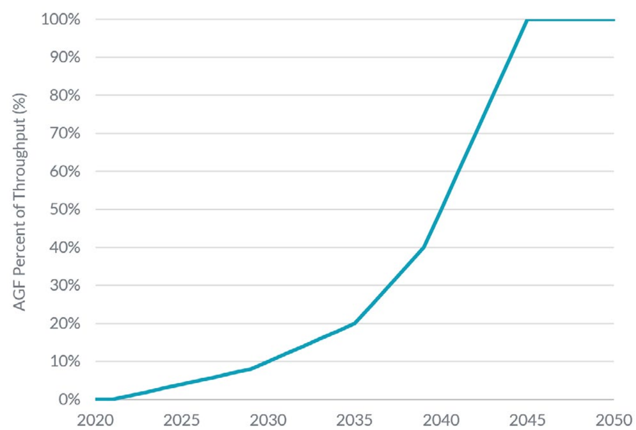
Sales. Using BDC heating stock results and historical utility sales, we determined total gas sales per utility. Our projection shows that total volumetric gas sales decrease from 2020 to 2050, by 89 percent for BGE, 90 percent for WGL, and 84 percent for Columbia. Figure 8 shows residential volumetric gas sales by utility.

Figure 8. Residential gas sales by utility



To meet Maryland's climate goals, all remaining gas throughput in the pipeline system is alternative gaseous fuels by 2045. This is shown in Figure 9.

Figure 9. SSE alternative gaseous fuels percent of throughput



4.2.3. Utility-Specific Modeling Results

Rate base per customer

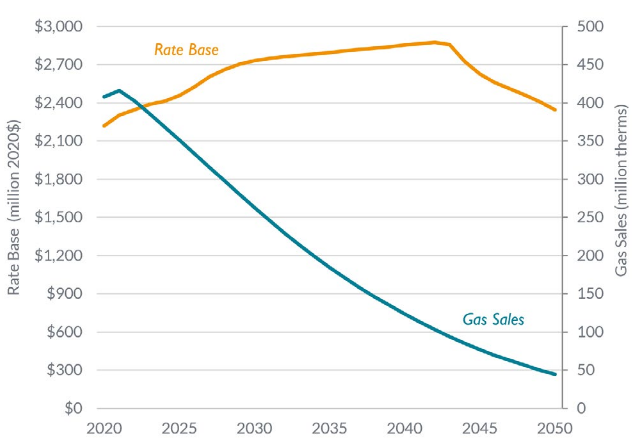
Rate base is the total value of the original cost of assets used and maintained by a utility less accumulated depreciation. Rate base is an identifiable, yet changing, number that has been approved in a regulatory proceeding—generally a rate case in which regulators approve a utility's capital expenditures. The amount of rate base is the cumulation of a utility's capital spending, paid for by customers, and is multiplied by the utility's rate of return (the cost of its debt and equity) to calculate the utility return on its investments. Customers pay down rate base when they pay the utility's depreciation expense that is reflected in the rates on their bills.

To keep rate base (and therefore rates) constant with gas sales continuing at the same level, a utility's approved spending on new capital assets must not exceed the pace at which its existing assets are retired, as customers pay for them through depreciation expense. Rate base—and rates—must increase when regulators approve utilities' capital expenditures (e.g., to replace old infrastructure and for system expansion) faster than existing assets are retired. And if sales are declining, rates must be increased even further to cover the fixed original costs of a utility's previous and ongoing approved capital expenditures. In other words, if utilities invest in pipeline infrastructure faster than existing assets are depreciated and despite decreasing numbers of customers and sales, they will seek substantial rate increases to recover the fixed costs of their rate bases.

Figures 10 through 12 illustrate declines in customers and sales. The figures show that with electrification, the utility's rate base becomes bigger and bigger relative to the utility's fuel throughput (or sales). This drives substantial increases in the utility's rates (the charges per unit measured in a therm of gas throughput) so that the utility can recover its rate-base-related costs across its reduced sales. Rate increases, in turn, will further drive customers off the gas system. **As high levels of customers abandon the gas system over a short period of time, the utility will be forced to strand assets.**

As shown in Figure 10, BGE's STRIDE program increases the utility's rate base and keeps it at roughly that level through the early 2040s. After the completion of its current STRIDE program, rate base falls slightly, assuming customers continue to pay the utility's depreciation expense.

Figure 10. BGE rate base, in real $2020 (left axis) and gas sales (right axis), in the SSE scenario



WGL has a smaller remaining STRIDE program, projected to end in the mid-2030s. Rate base starts to decline gradually around 2028 when annual STRIDE costs decrease about 55 percent compared to the previous year; it decreases faster in 2036 when its current STRIDE program ends, as shown in Figure 11.

Figure 11. WGL rate base, in real $2020 (left axis) and gas sales (right axis), in the SSE scenario

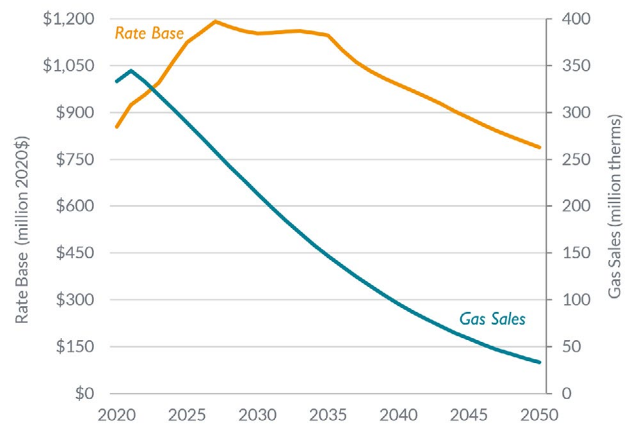
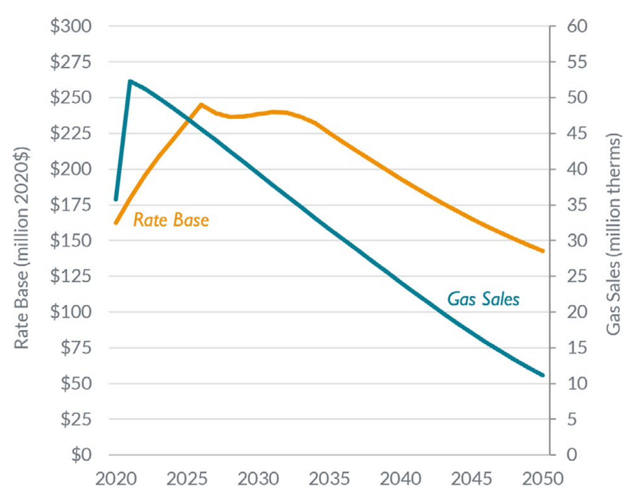


Figure 12 shows that Columbia Gas's rate base begins to flatten out and eventually decline after 2026, when its current STRIDE program ends.

Figure 12. Columbia Gas rate base, in real $2020 (left axis) and gas sales (right axis), in the SSE scenario



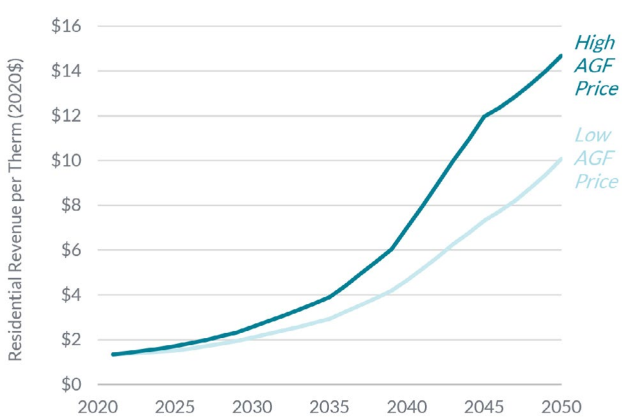
Rates

We approximate utility rates under SSE by taking the utility's annual revenue requirement (including fuel costs, return on rate base, and depreciation and operating expenses) and dividing by the projected amount of gas sold to customers.

We modeled two fuel cost sensitivities to determine the range of potential customer rates. The Low AGF Price ranges from $14.37 per MMBtu to $22.92 per MMBtu and the High AGF Price is set at $69.03 per MMBtu (all in $2020). From 2020 to 2050, utility rate base increases in the near term and stays relatively high (as seen above in Figures 10 through 12). Due to electrification, however, the total therms of gas throughput decreases. At the same time, fuel costs rise as fossil gas is replaced with alternative gaseous fuels. As a result, the revenue the utility must receive per therm sold—i.e., customer rates—must rise for the utility to recover its costs. The effect on customer rates—the required revenue per therm—is illustrated in Figures 13 through 15. The results show that **sector-specific electrification will lead to substantial increases in gas rates**.

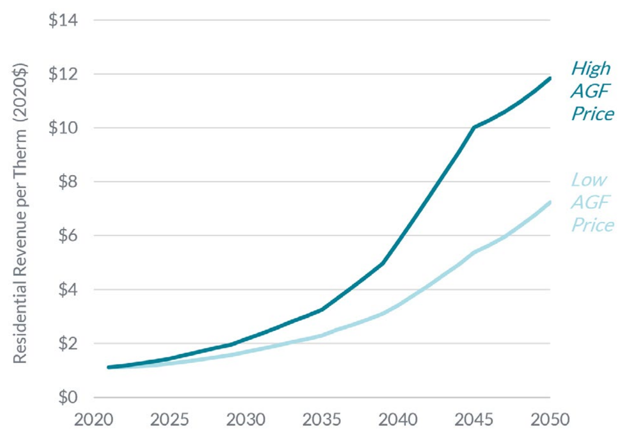
For BGE, our analysis shows that rates increase from $1.34 per therm in 2021 to $2.94 per therm in 2035 and $10.06 per therm by 2050 under the Low AGF Price scenario. In the High AGF Price scenario, the rates increase from $1.34 per therm in 2021 to $3.90 per therm in 2035 and $14.68 per therm in 2050.

Figure 13. BGE residential gas rates



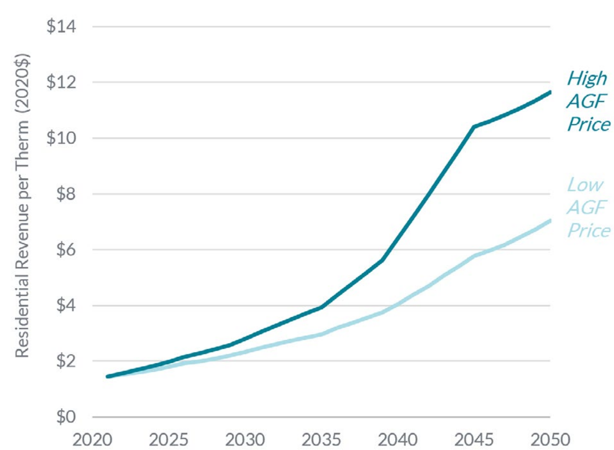
For WGL, our analysis shows that rates increase from $1.11 per therm in 2021 to $2.30 per therm in 2035 and $7.23 per therm by 2050 under the Low AGF Price scenario. Under the High AGF Price scenario, rates increase from $1.11 per therm in 2021 to $3.26 per therm in 2035 and $11.85 per therm in 2050.

Figure 14. WGL residential gas rates



For CMD, our analysis shows that rates increase from $1.44 per therm in 2021 to $2.97 in 2035 and $7.03 per therm by 2050 under the Low AGF Price scenario. In the High AGF Price scenario, rates increase from $1.44 per therm in 2021 to $3.93 per therm in 2035 and $11.65 per therm in 2050.

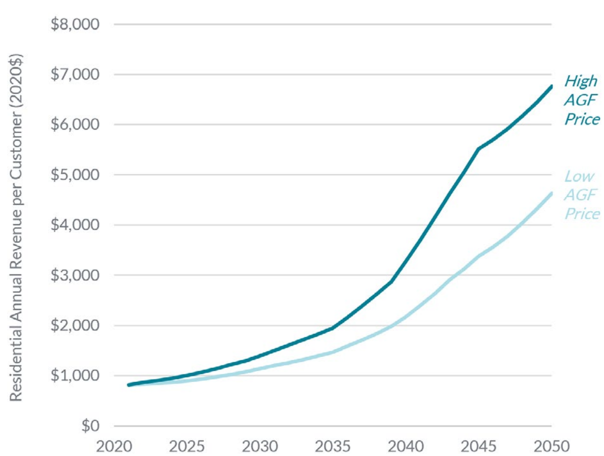
Figure 15. Columbia residential gas rates



Bill impacts of rate increases

Figures 16 through 18 show the annual energy-related operating cost of an average home for space and water heating end-uses under the SSE scenario for BGE.[44] Figure 16 shows the calculation for BGE. In the SSE scenario, building operating costs for residential customers staying on the gas system increase considerably by 2050, from $820 per year in 2021 to $1,464 per year in 2035 and $4,634 per year in 2050 under the Low AGF Price scenario. In the High AGF Price scenario, building operating costs for residential customers increase from $820 per year in 2021 to $1,944 per year in 2035 and $6,759 per year in 2050.

Figure 16. BGE residential building total gas costs (Low and High AGF Price)



As seen in Figure 17, WGL residential building operating costs increase from $780 per year in 2021 to $1,315 per year in 2035 and $3,827 per year in 2050 under the Low AGF Price scenario. In the High AGF Price scenario, building operating costs for residential customers increase from $780 per year in 2021 to $1,868 per year in 2035 and $6,270 per year in 2050.

Figure 17. WGL residential building total gas costs (Low and High AGF Price)

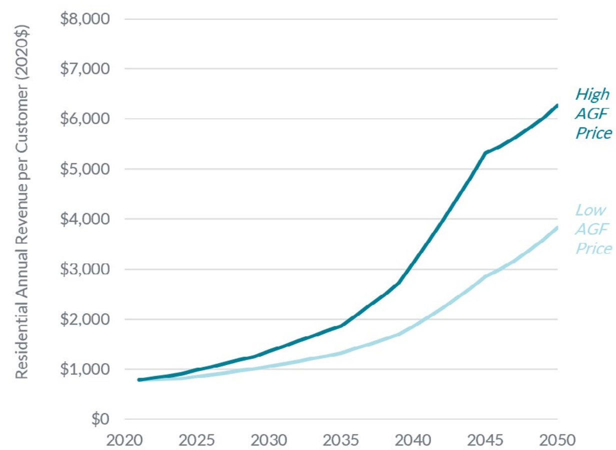
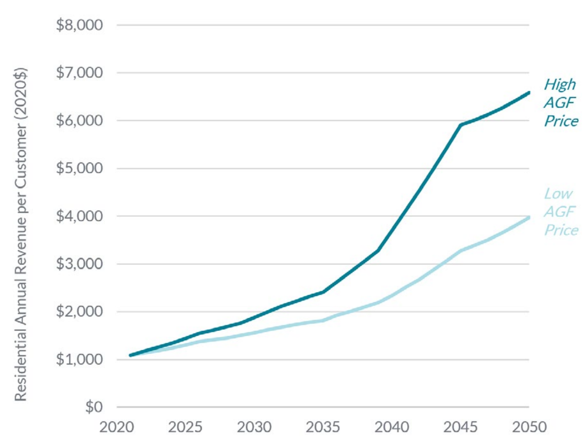


Figure 18 shows residential building operating costs for Columbia Gas. Costs rise from $1,086 per year in 2021 to $1,818 per year in 2035 and $3,979 per year in 2050 under the Low AGF Price scenario. In the High AGF Price scenario, building operating costs for residential customers increase from $1,086 per year in 2021 to $2,408 per year in 2035 and $6,591 per year in 2050.

Figure 18. Columbia residential building total gas costs (Low and High AGF Price)



44 These figures include the cost of fuel in addition to delivery costs.

The following tables provide a summary of the results of our modelling as shown in Figures 13 through 18 and described above.

2035 and 2050 range of residential rate impact depending on cost of alternative gaseous fuels

Rates ($2020/therm)

	2021	2035 AGF range	2050 AGF range
BGE	1.34	2.94 to 3.90	10.06 to 14.68
WGL	1.11	2.3 to 3.26	7.23 to 11.85
CMD	1.44	2.97 to 3.93	7.03 to 11.65

2035 and 2050 range of residential bill impact depending on cost of alternative gaseous fuels

Annual Bill (2020$)

	2021	2035 AGF range	2050 AGF range
BGE	$820	$1,464 to $1,944	$4,634 to $6,759
WGL	$780	$1,315 to $1,868	$3,827 to $6,270
CMD	$1,086	$1,818 to $2,408	$3,979 to $6,591

Importantly, Figures 13 through 18 provide the output for SSE modeling based on the *MWG Policy Scenario* that has heat pumps as the sole source of heating in over 95 percent of residential buildings by 2050. Our modeling achieves the 95 percent goal by gradually increasing heat pumps' share of the Maryland market from 2021 to 2050. As gas rates rise, however, customers will become increasingly likely to electrify their homes to avoid high gas rates. Thus, customer migration away from gas could be faster than the projections we used in modeling SSE. This increase in customer departures would further increase gas rates and perpetuate the cycle of customer departures and increasing rates for customers who remain on the gas system.

Customer migration away from gas could be faster than the projections used.

4.3. Implications of Analysis

The rapid decline in gas sales, together with a flat or increasing rate base (as shown in Figures 10 through 12), cause the dramatic increases in customer rates and bills found in our modeling of SSE in Section 4.2.3. While the overall impact on customer energy bills—across both electric and gas utilities—is beyond the scope of our analysis, our modeling confirms E3's conclusion that *gas* rates for residential customers remaining on the gas system will increase significantly as the State acts to meet its climate goals if the utilities do not alter their practices as a result of customer departures.[45]

Our analysis further holds important implications for the fixed costs that remain in the utilities' rate bases for decades into the future due to ongoing utility capital spending. Electrification will happen gradually as the building stock turns over. Gas rate increases due to electrification will also be gradual. But at some point, it could prove difficult—if not impossible—for gas rates to increase to the levels necessary for gas utilities to recover their fixed rate base costs and remain economically viable. Customers will electrify to avoid the high gas rates, and customers without alternatives nevertheless may not be able to afford continued gas service. If and when this plays out, the utilities will have substantial unrecovered and uneconomic assets remaining in rate base and on their books.

We note that such outcomes can be mitigated. If utilities adapt to electrification, they will be able to update their spending practices to lessen their revenue requirements to slow customer rate increases. In doing so, the utilities can mitigate their stranded assets, and customers who are unable to electrify in the near term will not see costs rise as rapidly.

45 MCCC, *Building Energy Transition Plan: A Roadmap for Decarbonizing the Residential and Commercial Building Sectors in Maryland*, at p. 14.

APPENDIX A

GLOSSARY AND ABBREVIATIONS

Term	Definition	Source
Alternative Gaseous Fuels	Non-conventional fuels such as hydrogen and various forms of natural gas including renewable, synthetic, and biomethane.	Environmental Protection Agency. "Alternative Fuels." Oct. 4, 2021. *Renewable Fuel Standard Program*. Available at: https://www.epa.gov/renewable-fuel-standard-program/alternative-fuels.
Biomethane	Pipeline-quality natural gas substitute produced by purifying biogas, a methane-rich gas produced from organic materials (also known as Renewable Natural Gas).	Natural Gas Vehicles for America. "The Potential of Renewable Natural Gas," 7 Jan. 2009, https://afdc.energy.gov/files/pdfs/biomethane_4.pdf. Accessed 6 July 2022.
Depreciation	The loss in service value not restored by current maintenance and incurred in connection with the consumption or prospective retirement of property in the course of service from causes against which the carrier is not protected by insurance, and the effect of which can be forecast with a reasonable approach to accuracy.	"18 CFR Ch. I, Pt. 352." *Code of Federal Regulations*. Available from: https://www.ferc.gov/sites/default/files/2020-06/18cfr352.pdf. Accessed 6 July 2022.
Fugitive Emissions	Unintended leaks of gas from the processing, transmission, and/or transportation of fossil fuels.	Glossary - U.S. Energy Information Administration (EIA), https://www.eia.gov/tools/glossary/.
Hydrogen (by type)	**Green hydrogen** is made by using clean electricity from surplus renewable energy sources, such as solar or wind power, to electrolyze water. **Blue hydrogen** is created from natural gas using steam methane reformation; the process captures and stores the emitted carbon dioxide underground. **Gray hydrogen** is created from natural gas using steam methane reformation but without capturing the greenhouse gases made in the process.	National Grid. "The Hydrogen Colour Spectrum." Available at: https://www.nationalgrid.com/stories/energy-explained/hydrogen-colour-spectrum.
Rate Base	The net investment of a utility in property that is used to serve the public; this includes the original cost net of depreciation, adjusted by working capital, deferred taxes, and various regulatory assets—the term is often misused to describe the utility revenue requirement.	Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/.

Term	Definition	Source
Recovered Methane	Methane gas that is captured from landfills, wastewater facilities, and farmland through the use of anaerobic digesters.	Environmental Protection Agency. "Learning About Biogas Recovery." *EPA*. Available at: https://www.epa.gov/agstar/learning-about-biogas-recovery.
Return on Equity	The rate of earnings realized by a utility on its shareholders' assets, calculated by dividing the earnings available for dividends by the equity portion of the rate base.	New York State Public Service Commission. "Glossary of Terms Used by Utilities and Their Regulators." Available at: https://www.dps.ny.gov/glossary.html.
Revenue Requirement	The annual revenues that the utility is entitled to collect (as modified by adjustment clauses). It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base. In most contexts, revenue requirement and cost of service are synonymous.	Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/.
Stranded Assets	Assets that have suffered from unanticipated or premature write-downs, devaluation or conversion to liabilities.	Lloyd's. 2017."Stranded Assets." Available at: https://www.lloyds.com/strandedassets.
Synthetic Natural Gas	A manufactured product, chemically similar in most respects to natural gas, resulting from the conversion or reforming of hydrocarbons that may easily be substituted for or interchanged with pipeline-quality natural gas.	U.S. Energy Information Administration. *Glossary - U.S. Energy Information Administration (EIA)*, https://www.eia.gov/tools/glossary/.

Abbreviation	Term
AGF	alternative gaseous fuels
BDC	Building Decarbonization Calculator
BGE	Baltimore Gas and Electric
C&I	commercial and industrial
GHG	greenhouse gas
GRM	Gas rate model
MWG	Mitigation Work Group
OPC	Office of People's Counsel
STRIDE	Strategic Infrastructure Development and Enhancement program
SSE	Sector Specific Electrification
WGL	Washington Gas Light

APPENDIX B

DETAILED COMMERCIAL RESULTS

Figure B-1. Commercial on-site space and water heating GHG emissions, before accounting for use of low- or zero-carbon gas or off-site emissions

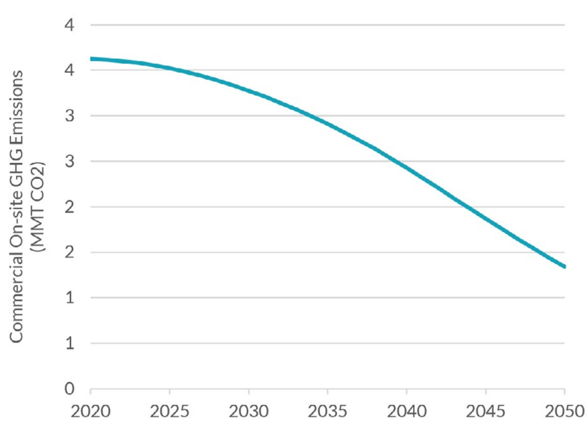


Figure B-3. Commercial building stock by space heating fuel and technology

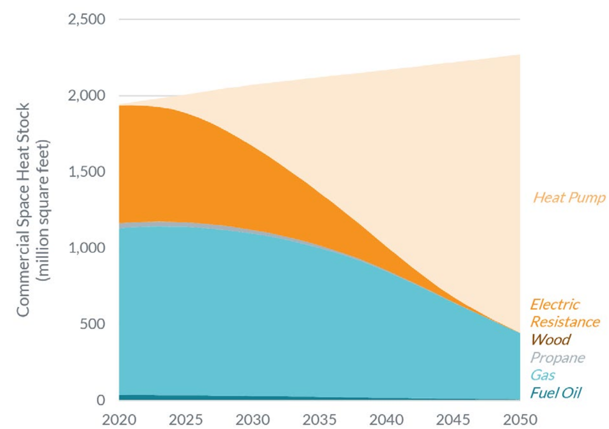


Figure B-2. Commercial gas consumption

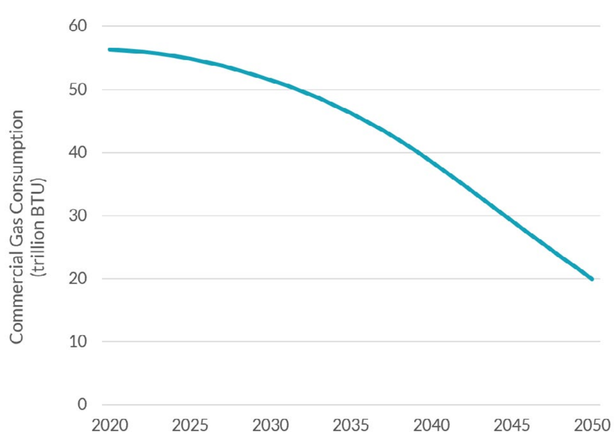
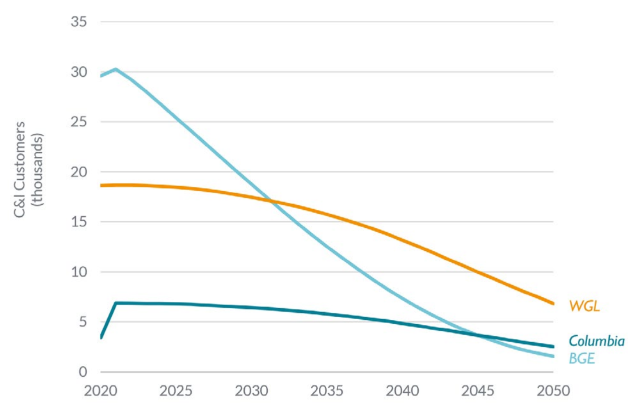


Figure B-4. Commercial and industrial customers by utility



B-5. Commercial and industrial gas sales by utility

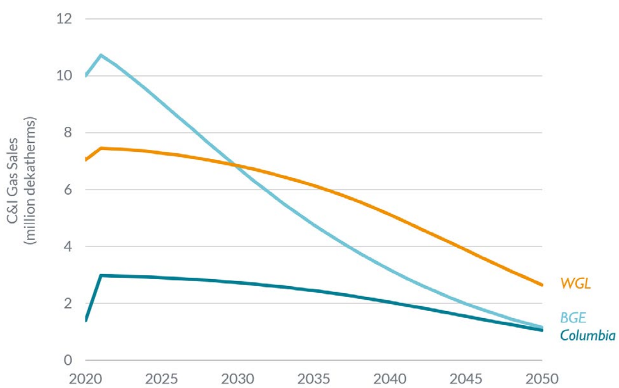


Figure B-6. BGE commercial and industrial building total gas costs (Low and High AGF Price)

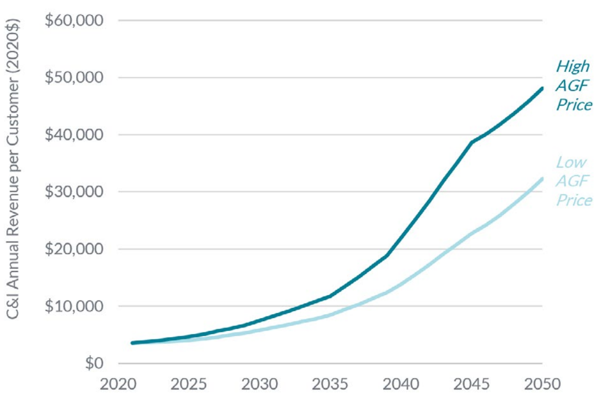


Figure B-7. WGL commercial and industrial building total gas costs (Low and High AGF Price)

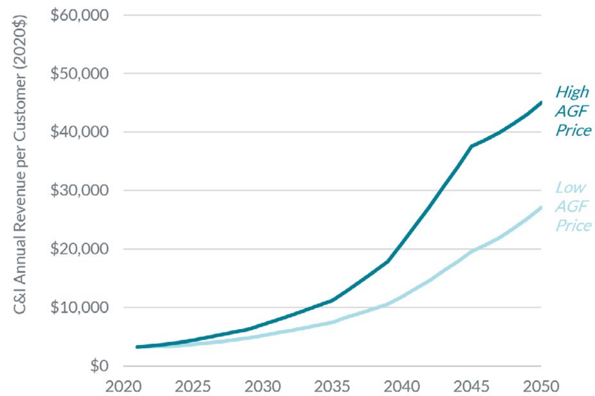
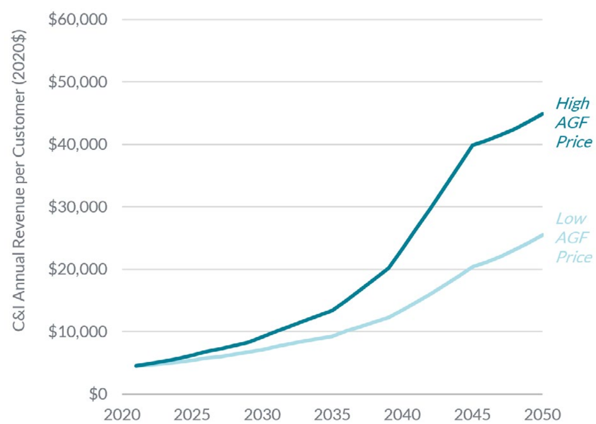


Figure B-8. Columbia Gas commercial and industrial building total gas costs (Low and High AGF Price)



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Appendix E

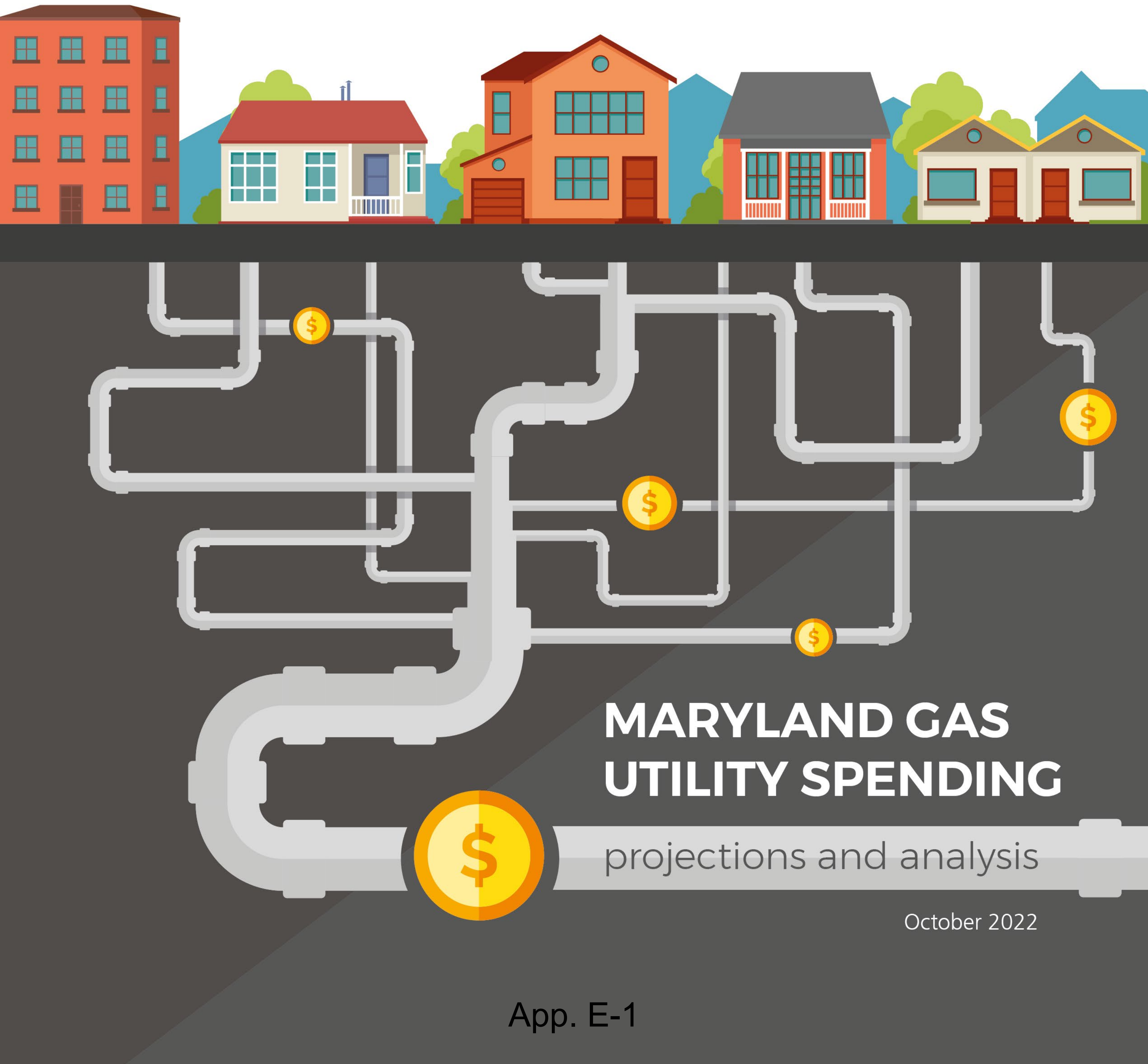
OPC GAS SPENDING REPORT

Appendix E

OPC

OFFICE OF PEOPLE'S COUNSEL

State of Maryland



MARYLAND GAS UTILITY SPENDING

projections and analysis

October 2022

DEAR READERS

Policymakers and customers are making long-term decisions about the future of natural gas. Policymakers are deciding what role—if any—gas will play in the State's effort to meet its climate goals. And every day, customers are deciding what types of appliances will heat their homes, water, and stoves for the next two decades. Making the right decisions depends on access to good information. To make decisions about natural gas, distribution system costs and commodity costs are the two key components of customer gas bills that need to be understood.

This report focuses on the cost impacts of the *distribution system spending*—costs that customers pay utilities for delivering gas—with less emphasis on gas *commodity prices* (which currently are more than double what they were 18 months ago). This focus is appropriate because—unlike gas commodity costs—the cost impact of gas utility distribution system spending is subject to State policies that can control and mitigate those costs.

It should be easy to identify how much gas companies with government-granted franchise monopolies plan to spend on delivering gas; after all, their captive customers pay for it.

But it is not easy.

Utility spending is siloed into different programs and categories of costs, and it is generally subject to regulatory oversight only *after* or shortly before customer dollars are spent. Utilities are also not generally required to publicly disclose their long-term spending plans—much less engage in any sort of transparent comprehensive planning process that invites public input.

This failure of transparency represents a major regulatory gap that leaves customers and policymakers alike in the dark on how utilities will spend billions of customer dollars in the coming decades.

To identify just how many customer dollars the gas utilities are on track to spend, our office engaged DHInfrastructure to analyze utility filings and relevant Public Service Commission orders, and make reasonable assumptions to project future gas utility spending, and assess what that spending means for residential utility customers. We directed DHInfrastructure to make calculations based on business-as-usual spending, without accounting for spending reductions resulting from State climate policy or otherwise. This business-as-usual assessment is important because the utilities are not proposing to scale back any of their spending; in fact, quite the opposite—Maryland's gas utilities are accelerating their capital spending and pushing

This report shows that without significant regulatory action, gas utility customers will see substantial and continuing increases in their gas bills in the coming years to pay for accelerating capital spending.

back against efforts to slow it down. This report shows that without significant regulatory action, gas utility customers will see substantial and continuing increases in their gas bills in the coming years to pay for accelerating capital spending. This problem—creating continuing, long-term, significant upward pressure on gas bills—predates and exacerbates the very large increases in gas bills, during 2022 and anticipated for the winter of 2022/3, due to the dramatic recent increases in the gas commodity portion of gas utility bills.

While the projections contained in the following report represent business-as-usual, they are *conservative* about how high gas utility rates may go. **The utilities' spending and the customer-bill impacts of that spending, combined with gas commodity prices, could be significantly larger than the report shows for at least three reasons.**

1. **Some degree of electrification appears inevitable.** This means the amount of gas moving through the pipes will decline as customers replace their appliances and heating systems with all-electric systems. Since utilities' spending will be recovered among fewer customers and sales, rates for remaining gas customers will increase *more* than reflected in this report.

2. **The pace of gas investments has accelerated in recent years.** But because we do not think the current growth rate can be maintained, as the report explains at Section 2.2, DHInfrastructure modelled slower growth.

3. **The report uses conservative gas commodity prices.** It uses a commodity cost based on the average February gas commodity price for the last five years, which is less than $0.50/therm for each utility. The model thus shows commodity prices *significantly lower* than gas commodity prices are today. For example, Washington Gas Light's commodity price for residential and general service as we head to press (in September 2022), is $ 1.1314/therm, more than double the commodity price we model.

For these three reasons, our projections on spending and rates are conservative; actual gas utility spending and gas utility customer bills could be significantly higher than these projections.

We hope this report helps educate stakeholders and policymakers on the significance of unmitigated gas utility spending for Maryland's gas utility customers.

David S. Lapp
People's Counsel

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SECTION ONE

EXECUTIVE SUMMARY

Maryland's Office of People's Counsel (OPC) engaged DHInfrastructure to prepare various projections and analyses on the current trajectory of gas infrastructure investments and corresponding rate impacts of the projected level of investment at the State's three largest gas distribution companies: Baltimore Gas and Electric (BGE), Washington Gas Light (WGL), and Columbia Gas of Maryland (CMD). Using conservative assumptions, the report's findings show that a continuation of the utilities' spending practices means significantly higher costs for gas delivery, resulting in higher bills for most Maryland residential customers.

This report discusses the approach and assumptions used to develop the projections, presents the results of the projections, and then includes a brief written analysis on the results. It also reports on recent historical trends in natural gas distribution and commodity rates based on actual data. Below we summarize the findings.

Maryland's three largest gas companies are currently undertaking massive capital investment programs through STRIDE...

In 2013, the Maryland General Assembly enacted the Strategic Infrastructure Development and Enhancement (STRIDE) law, section 4-210 of the Public Utilities Article, *Annotated Code of Maryland* (section 4-210 or STRIDE statute). The STRIDE statute authorizes Maryland gas utility companies to file and the Public Service Commission to approve infrastructure investment plans and corresponding project cost-recovery schedules.

The statute requires that companies receive PSC approval of their STRIDE plans on five-year cycles. BGE, WGL, and CMD all requested and received approval for initial five-year plans in 2013 and are currently on their second five-year plans that run from 2019 to 2023. Table 1.1 below shows that the utilities complete their STRIDE plans on file with the PSC at different stages, with BGE's extending to its sixth five-year plan running through 2043. This timeline indicates that for some Maryland utilities, STRIDE is still only in the early stages. Based on each of the three company's STRIDE plans, we find that there is upward of $4,764 million remaining to be invested through STRIDE alone over the next 20-plus years.

Table 1.1: STRIDE Investment Plans of Maryland's Three Largest Gas Utilities (million $)

	BGE	WGL	CMD	THREE-COMPANY TOTAL
Total spent STRIDE I (actual 2014-2018)	$522.73	$218.50	$66.19	
Actual/Authorized budget STRIDE II (2019-2023)	$827.28	$363.07	$87.22	
Estimated STRIDE III (2024-2028) budget	$693.39	$439.44	$57.38	
Estimated STRIDE IV (2029-2033) budget	$803.83	$194.82	$0	
Estimated STRIDE V (2034-2038) budget	$931.86	$86.35	$0	
Estimated STRIDE VI (2039-2043) budget	$1,034.48	$0	$0	
All-time Total STRIDE I – VI	$4,813.58	$1,302.19	$210.79	$6,326 million
Future Total = Remaining STRIDE II + STRIDE III to STRIDE VI	$3,793.70	$877.71	$92.94	$4,764 million

Totals in figures and tables may not add up precisely due to rounding.

...and these companies will continue to make other investments outside of STRIDE well into the future.

Maryland gas utilities are also continuing to invest in other capital asset categories not covered by STRIDE. Our conservative estimate is that if the companies spend on non-STRIDE activities at current levels, there will be another $29,749 million investments outside of STRIDE between 2022 and 2100. As shown in Table 1.2, the combined STRIDE and non-STRIDE investments are $34,513 million.

Our conservative estimate is that if the companies spend on non-STRIDE activities at current levels, there will be **another $29,749 million in investments outside of STRIDE** between 2022 and 2100.

Table 1.2: Maryland Gas Capital Expenditure (CAPEX) Investments, 2022-2100 (million $)

	STRIDE (2022-2043)	Non-STRIDE (2022-2043)	Non-STRIDE (2044-2100)	Total
BGE	$3,793.70	$5,799.14	$15,005.96	$24,598.80
CMD	$92.95	$235.31	$609.67	$937.93
WGL	$877.71	$2,255.34	$5,843.39	$8,976.45
Total	$4,764.36	$8,289.79	$21,459.02	$34,513.18

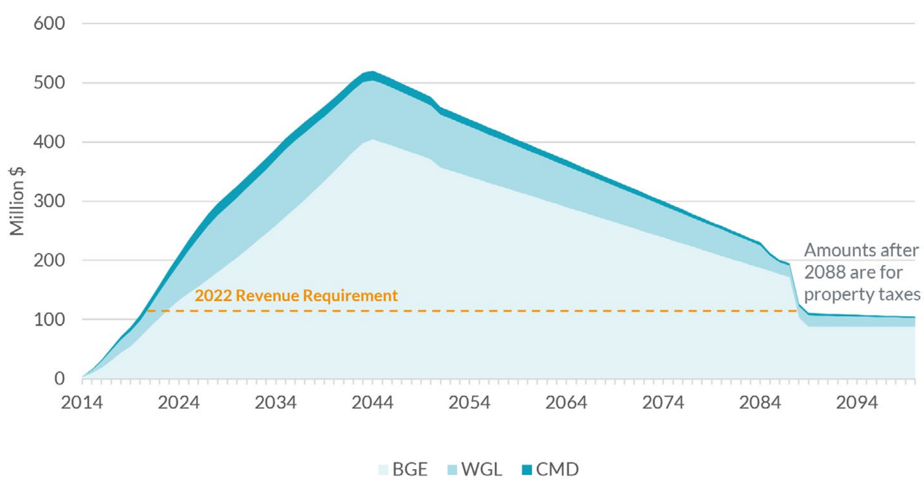
If this pace of investment continues, the capital component of the revenue requirements collected from customers will more than double over the next 25 years...

To understand the impact of our capital investment projections on gas utility rates, we first developed a revenue requirement model that estimated the capital-related components of the revenue requirement. Roughly speaking, the "revenue requirement" consists of the utility's total revenue needs; the annual revenue requirement is divided by anticipated sales to arrive at the per therm rate that customers pay. (The term is defined in the glossary at the end of this report.) Importantly for customers, the capital investment portion of the revenue requirement accounts for only the costs related to the utilities' spending on capital expenditures such as depreciation, return on equity, and property taxes; it does not include (a) the utilities' operational costs nor (b) gas commodity costs that customers pay in their bills.

All utility capital investment enters the utility's rate base. The rate base is the undepreciated value of utility plant-in-service, composed of the utility's prior capital investments less accumulated depreciation. It determines the capital investment-related portion of the utility's revenue requirement (i.e., the annual revenues the utility is authorized to recover from its customers through its rates). Capital investments are recovered from the utility's customers over time—through a depreciation charge, which is often more than 30 years, and as long as 70 years, depending on the expected life of the asset—until it is fully depreciated. Customers pay both a "return of" investments, in the form of depreciation, and a "return on" investments equal to the utility's weighted average cost of capital (WACC), which is expressed as a percentage multiplied by the utility's rate base.[1]

The pyramid figure below was made using the revenue requirement model. What makes this figure informative is that it provides context for where the utilities currently are in their overall STRIDE plans. As identified by the orange dotted line, the combined

Figure 1.1: STRIDE Annual Revenue Requirement Pyramid



If STRIDE plans continue as currently constituted, **customers could eventually be paying more than three times** for STRIDE investments than the amounts they are spending today.

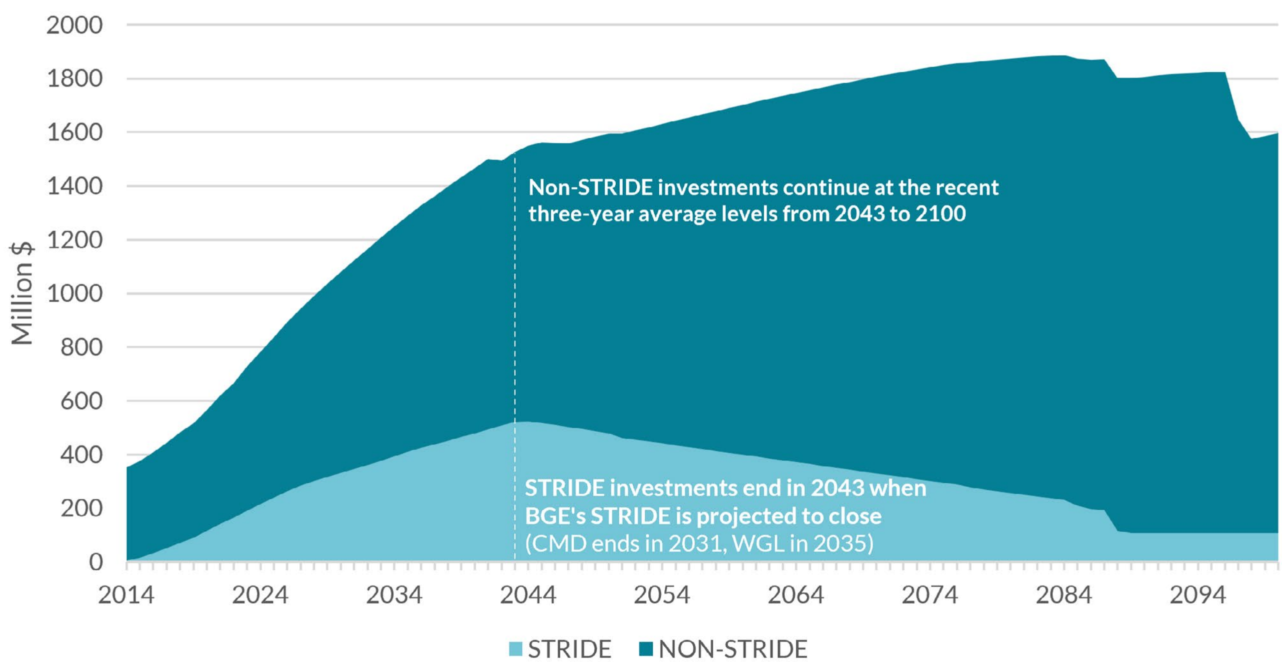
1 The capital-related revenue requirement also includes a tax "gross-up," including the federal and state income taxes owed if the utility earns its WACC, the property taxes related to the capital investment, and certain other miscellaneous fees.

2022 capital investment component of the utilities' revenue requirement of approximately $160 million across the three STRIDE programs represents a fraction—30 percent—of the $524.1 million peak in STRIDE revenue requirements that we project for 2044. In other words, if STRIDE plans continue as currently constituted, then Maryland customers could eventually be paying more than **three times** for STRIDE investments than the amounts customers are paying today.

The STRIDE annual revenue requirement amounts (Figure 1.1) represent only a fraction of the total aggregate capital investment-related revenue requirements customers will need to pay to cover utility capital investments made over the next 80 years. The STRIDE and non-STRIDE capital additions we project through 2100 would result in an annual capital revenue requirement for the three utilities exceeding $1.5 billion by 2043, or **2.3 times** the combined $667 million in capital investment-related revenue requirements customers are paying through rates in 2022. Put another way, customers today are responsible for paying less than half of the capital investment-related costs that customers will be responsible for in 2043. Figure 1.2 provides both a comparison of the combined non-STRIDE (dark teal) and STRIDE (light teal) capital investment-related revenue requirements across the combined three companies and shows how the total capital investment-related revenue requirements (dark teal + light teal) will evolve over time.

Customers today are responsible for paying less than half of the capital investment-related costs that customers will be responsible for in 2043.

Figure 1.2: Combined Three-Company STRIDE and Non-STRIDE CAPEX Annual Revenue Requirement



…which will result in corresponding increases in base rates charged to customers to cover the rise in rate base.

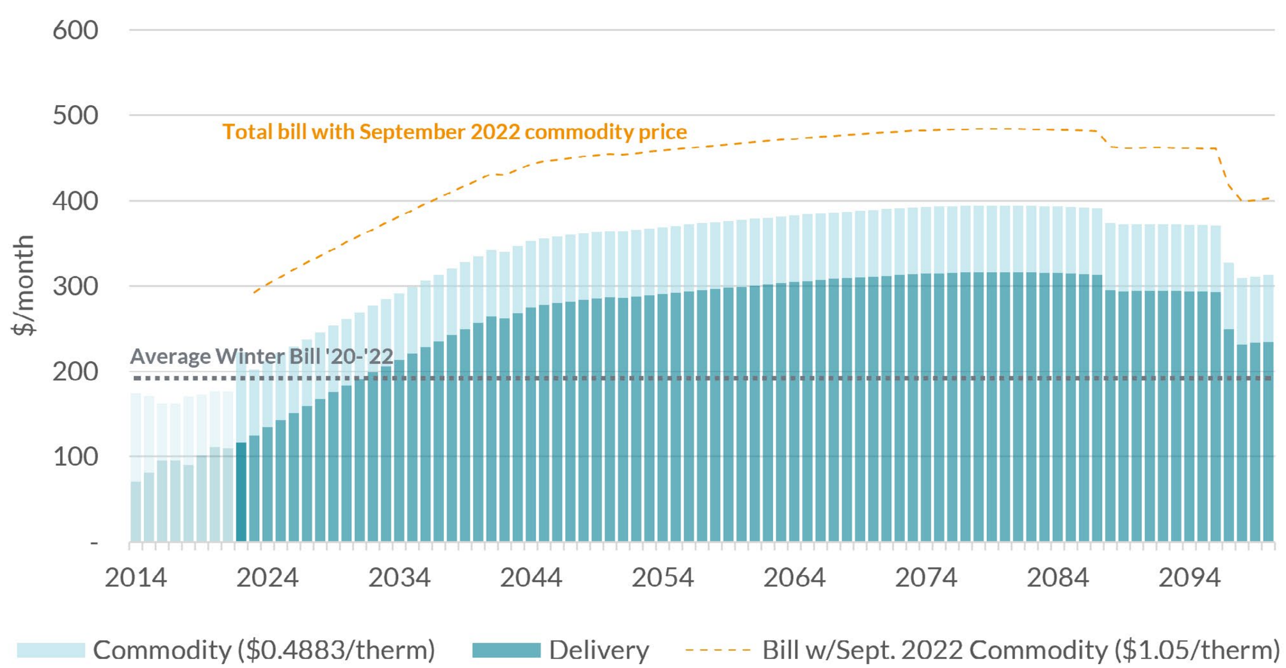
Next, we identified how the capital investments will affect customer rates. This step allocates revenue to the residential heating class of each company using the revenue allocation factors from the most recent STRIDE filings. The billing determinants for customer-months and usage were set based on the revenue calculations in the compliance filing from the most recent rate case for each company. The customer and sales numbers are assumed to remain constant over the evaluation period. Stated otherwise, the projections do *not* account for any migration of gas customers to electric service as a result of electrification policies.

To show the bill impacts over time, we evaluate the typical bill for a winter customer using 160 therms per month in January and February. We use this period because these months tend to be the highest bills for customers.

Figure 1.3 shows that the BGE typical residential customer's bill will grow from an average of $192 in 2020-2022 to $299, a 56 percent increase by 2035, and $364, a 90 percent increase by 2050. This assumes commodity prices revert back to the five-year averages. If gas prices stay near the current September levels ($1.05/therm for BGE), then that would add an additional $90 per month to the typical winter bill.

The BGE typical residential customer's bill will **increase 56% by 2035.**

Figure 1.3: BGE Typical Winter Bill, 2014-2100



BGE rates for 2021 and 2022 include the Rider 18 offset that was adopted to lower bills in the first two years of the MYRP. This offset amount is removed after 2022.

Figure 1.4 shows that the WGL typical residential customer's bill will grow from an average of $160 in 2020-2022 to $224, a 40 percent increase by 2035, and $230, a 44 percent increase by 2050. This, too, assumes commodity prices revert back to the five-year averages. If gas prices stay at the September 2022 level ($1.1314/therm for WGL), then that would add another $102 per month to the typical winter bill.

Figure 1.5 shows that the CMD typical residential customer bill will grow from an average of $186 in 2020-2022 to $270, a 45 percent increase, by 2035 and $276, a 48 percent increase, by 2050. If commodity prices remain at the September 2022 level

Figure 1.4: WGL Typical Winter Bill, 2014-2100

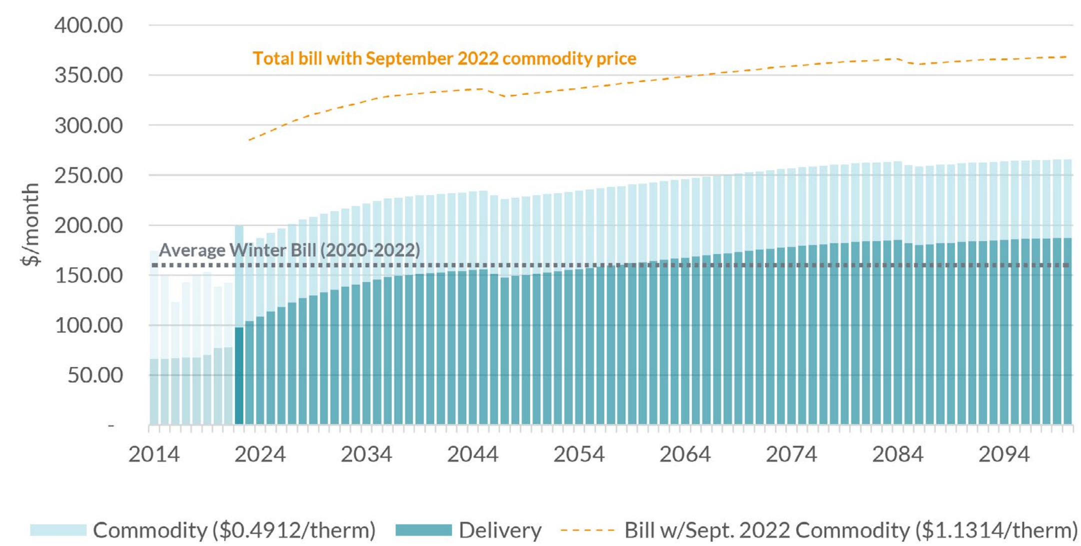
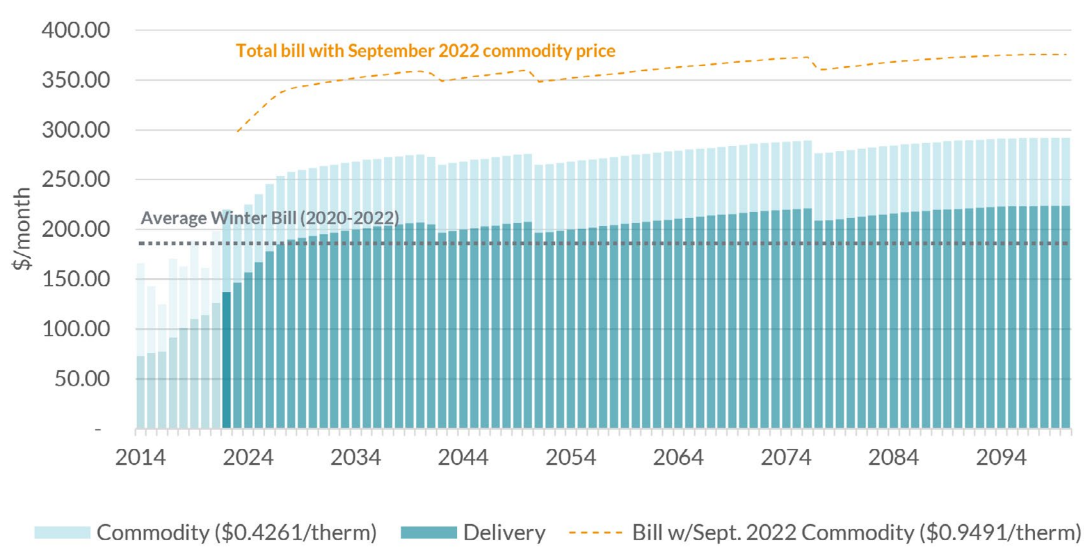


Figure 1.5: CMD Typical Winter Bill, 2014-2100



($0.9491/therm for CMD), that would add another $84 to the typical winter bill.

It is important to recognize that Maryland customers are only at the early stages of paying for STRIDE...

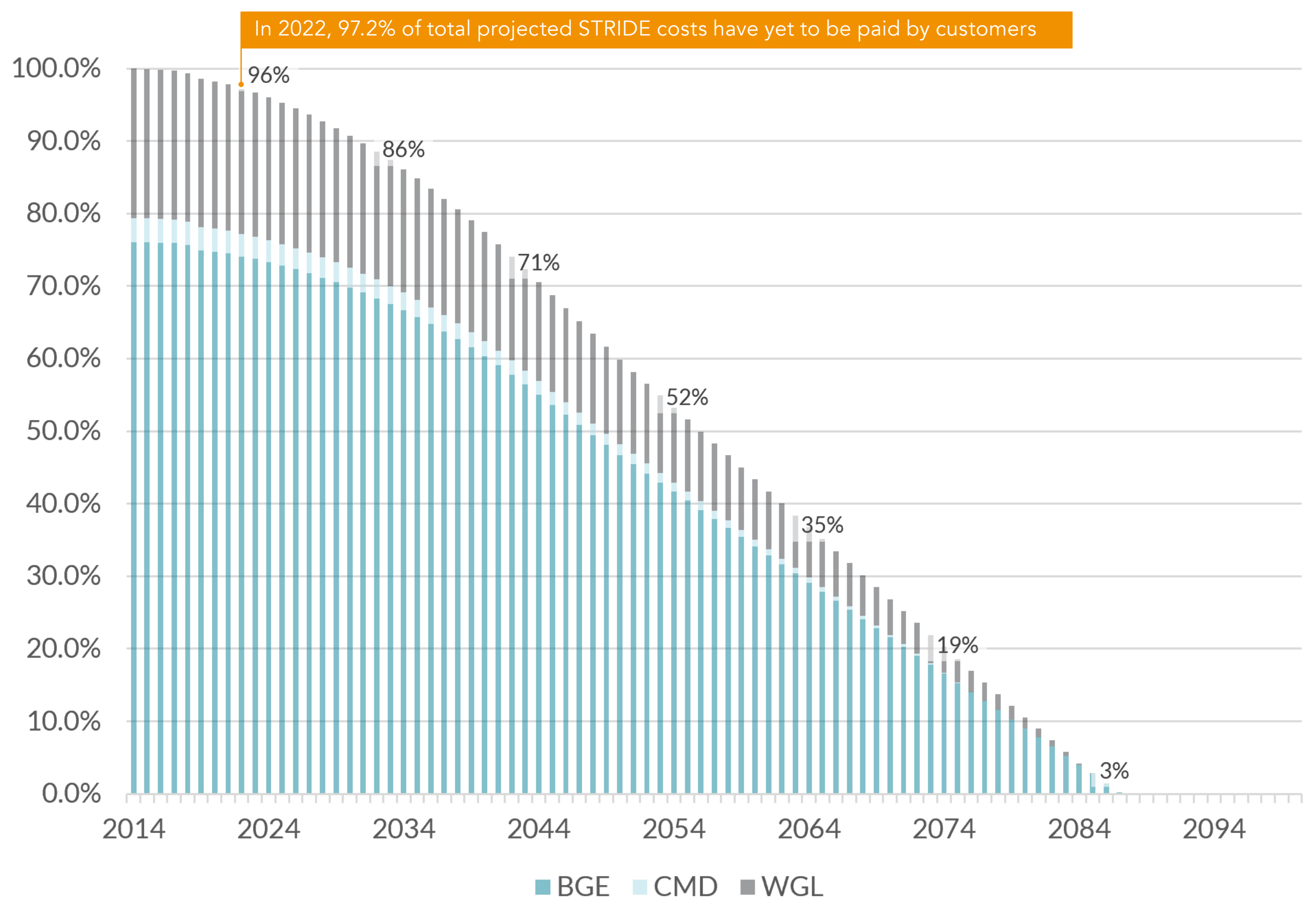
We determined the portion of the total STRIDE costs that have already been recovered through rates and, conversely, what portion of the STRIDE costs remain to be recovered. An investment is being "recovered" through rates until it is fully depreciated. Utilities under rate-of-return regulation receive a "return on" the undepreciated value of an investment in the form of a return on equity and a "return of" the investment in the form of depreciation expenses. Accordingly, we use cumulative STRIDE depreciation to represent the amounts recovered through rates.

We combined the results of the individual companies into Figure 1.6 to provide a wholistic view of the remaining years that STRIDE costs will be recovered through rates in Maryland. What is important to recognize from this figure is that right now, in 2022,

> Right now, in 2022, **only 2.8% of the planned STRIDE costs have been recovered** through rates.

only 2.8% of the planned STRIDE costs have been

Figure 1.6: Amount of STRIDE Cost Recovery Remaining Across Maryland's 3 Largest Gas Utilities



recovered through rates. STRIDE cost recovery is still at the early stages with Maryland customers expected to be paying off STRIDE costs until 2087.

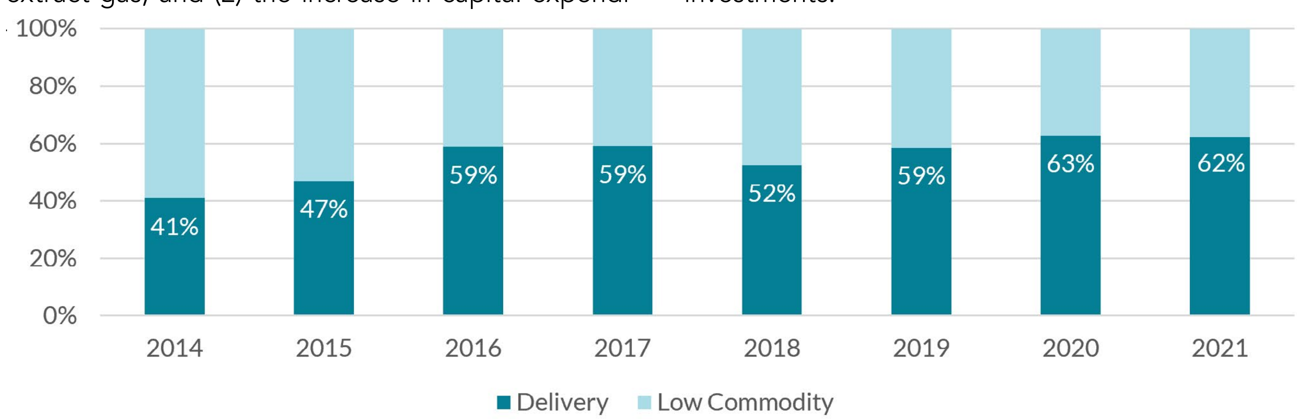
...and the true bill impact of these investments has partially been hidden from customers due to reduced gas prices.

Prior to the increase of gas commodity prices in 2021 and 2022, there had been a trend over the previous decade where the distribution proportion of bills was increasing, while the commodity portion of the bill decreased. This was due to two factors: (1) a drop in commodity prices caused by a large increase in U.S. domestic gas supplies due to the expanded deployment in the U.S. of hydraulic fracking techniques to extract gas, and (2) the increase in capital expenditures, specifically the STRIDE expenditures. The combined effect has been that the drop in commodity prices has offset the increase in base rates. Figure 1.7 shows how a notable flip occurred in 2016: Gas customers began paying more for *delivery* of the gas than for the gas commodity they use, as a proportion of their monthly gas bill.

The drop in commodity prices has offset the increase in base rates.

The increase in gas utilities' distribution prices (or the non-commodity "delivery price") has raised the floor for the total gas bill. When the commodity portion of the gas rate increases, as has happened in 2021 and 2022, customers bear the combined burden of both a return to higher commodity prices and the rise in base rates due to accelerated and increasing capital investments.

Figure 1.7: BGE Typical Winter Bill by Component, 2014-2021 (%)



SECTION TWO

CAPITAL PROJECTIONS

This section describes the approach we used to develop assumptions for the capital investments that BGE, WGL, and CMD will make from 2022 until 2100. The objective was to develop assumptions that approximate the status quo or current trajectory of each company's investments based on recent history and any capital plans that they have presented in regulatory proceedings.

Our assumptions are based on utility filings with the Public Service Commission or Commission orders. Where we have them, we use the utilities' own projections or assumptions.* If further assumptions are required, we use conservative estimates that are based on analysis of recent rate cases and existing utility plans. All assumptions are explained below.[2]

Table 2.1 summarizes the results of these capital projections, both by company in total for Maryland's three largest gas utilities. For perspective, the expenditures over the first eight years of STRIDE (2014-2021) by the three utilities have already been $1,562 million. This table shows that over the remaining duration of STRIDE, the companies anticipate expenditures ($4,764 million) that are triple what has already been spent on STRIDE. These STRIDE amounts will only be a portion of the overall capital expenditures (CAPEX).

*The utility-specific data on which this report is based comes from historical, publicly available information or the utility's projections contained in filings with the Public Service Commission or public reports.

To further ensure the accuracy of the general spending trends and customer impacts observed in this report, OPC provided certain data to the three utilities (BGE, WGL, and CMD) and asked them to confirm its accuracy. OPC informed the utilities that the data would be used in documents shared with the public. Both WGL and BGE responded by identifying where certain numbers in their records differed from the numbers DHInfrastructure identified. DHInfrastructure accordingly updated projections and models used for this report to reflect WGL's and BGE's comments. In other cases, each of which is described in detail in this report, DHInfrastructure made all attempts to use the best available public information. For example, because STRIDE projections are based on expenditures rather than plant-in-service, expenditures were used as a close proxy for plant-in-service; as explained in section 2.2.1, this difference has only a *de minimus* impact on our results. Both WGL and BGE emphasized that their willingness to review the data in no way constituted an endorsement of the numbers for any specific use, because they did not know the context in which the numbers would be used. CMD did not respond to OPC's request.

2 Nominal dollars are used in this report except for STRIDE long-term projections, for which utility filings include an annual 3% increase that may be intended to reflect inflation.

Table 2.1: Maryland Gas CAPEX Investments, 2022-2100 (million $)

	STRIDE (2022-2043)	Non-STRIDE (2022-2043)	Non-STRIDE (2044-2100)	Total
BGE	$3,793.70	$5,799.14	$15,005.96	$24,598.80
CMD	$92.95	$235.31	$609.67	$937.93
WGL	$877.71	$2,255.34	$5,843.39	$8,976.45
Total	$4,764.36	$8,289.79	$21,459.02	$34,513.18

We estimate that if the three companies continue to invest outside of STRIDE at current rates, there will be another $29,749 million in non-STRIDE investments between 2022 through 2100. In total, based on our assumptions about the current trajectory of investments, we estimate that these three utilities are on track to spend $34,513 million on gas CAPEX investment from 2022 through 2100.

The remainder of this section describes how these projections were developed. We begin in Section 2.1 with an overview of the STRIDE investment projections by company and then, in Section 2.2, identify the non-STRIDE capital investment assumptions.

2.1. STRIDE Projections

In 2013, the Maryland General Assembly enacted section 4-210 of the Public Utilities Article, *Annotated Code of Maryland* (section 4-210 or STRIDE statute). The STRIDE statute authorized Maryland gas utility companies to file infrastructure investment plans and corresponding project cost-recovery schedules with the Commission for approval. Eligible investments under STRIDE include infrastructure replacement or improvement projects that meet the following criteria:

- Made on or after June 1, 2013;
- Designed to improve public safety or infrastructure reliability;
- Does not increase the revenue of a gas company by connecting an improvement directly to new customers;
- Reduces or has the potential to reduce greenhouse gas emissions through a reduction in natural gas system leaks; and
- Is not included in the current rate base of the gas company as determined in the gas company's most recent base rate proceeding.[3]

Companies anticipate expenditures that are **triple what has already been spent**.

The statute requires that companies receive approval of their STRIDE plans on five-year cycles. BGE, WGL, and CMD are all on their second five-year plans that run from 2019 to 2023. As part of the filings made to support their second five-year plans, companies also provided updates on their overall STRIDE plans (i.e., the future five-year plans) through either testimony or discovery responses that were used to develop the future STRIDE expenditure projections. These future STRIDE plans continue until the gas utilities have replaced the gas infrastructure targeted by each plan. The subsections below describe each company's STRIDE program and identify the assumptions we used for future STRIDE investments.

3 Md. Code Ann., Public Utilities Article § 4-210 (a)(3).

Section 4-210 permits companies to begin recovering costs of approved STRIDE investments outside of a rate case through the STRIDE surcharge mechanism. Section 4-210 establishes the rate mechanism to be used to recover eligible costs as a "fixed annual surcharge on customer bills." This surcharge is capped at $2 per month for residential customers; for all non-residential customers, the surcharge cap is proportionate to each class's total distribution revenues as determined in the most recent base rate proceeding. When the Commission approves the investments in the utility's subsequent rate case and the previous STRIDE investments are allowed into rate base, the surcharge is reset to zero, subject to increasing again to recover the next round of STRIDE-eligible investments until the next base rate case. Thus, aside from the surcharge, customers are also paying for STRIDE investments through the per therm rates they pay (the "base rates").

Absent the surcharge mechanism, companies would not be able to begin to recover the investment costs of completed projects until these costs are included in rate base in the next base rate proceeding. The time gap between when a project is completed (or "in service") and when it is reflected in base rates is known as "regulatory lag." Cost recovery schedules under the STRIDE statute are initially based on estimated project costs, which are "collectible at the same time the eligible infrastructure replacement is made"[4] and these costs are reconciled annually. This estimate and reconciliation approach effectively eliminates regulatory lag such that companies receive contemporaneous recovery of STRIDE costs as they are incurred. This elimination of "regulatory lag" is the main mechanism by which STRIDE accelerates the replacement of natural gas infrastructure.

The three companies are all currently operating under their second five-year STRIDE plan. With STRIDE plans running until 2026 for CMD, 2035 for WGL, and 2043 for BGE, it is expected that there will be up to four more five-year cycles of STRIDE. Table 2.2 presents each company's future STRIDE plans.

It should be noted that the STRIDE investment amounts presented above are STRIDE expenditures, not "plant-in-service." When utilities invest in capital projects, under traditional rate of return ratemaking, they do not begin to recover these investments until they are "plant-in-service," which literally means that the equipment is operational and providing service to

Table 2.2: STRIDE Investment Plans of Maryland's Three Largest Gas Utilities (million $)

	BGE	WGL	CMD	THREE-COMPANY TOTAL
Total spent STRIDE I (actual 2014-2018)	$522.73	$218.50	$66.19	
Actual/Authorized budget STRIDE II (2019-2023)	$827.28	$363.07	$87.22	
Estimated STRIDE III (2024-2028) budget	$693.39	$439.44	$57.38	
Estimated STRIDE IV (2029-2033) budget	$803.83	$194.82	$0	
Estimated STRIDE V (2034-2038) budget	$931.86	$86.35	$0	
Estimated STRIDE VI (2039-2043) budget	$1,034.48	$0	$0	
All-time Total STRIDE I – VI	$4,813.58	$1,302.19	$210.79	$6,326 million
Future Total = Remaining STRIDE II + STRIDE III to STRIDE VI	$3,793.70	$877.71	$92.94	$4,764 million

4 Md. Code Ann., Public Utilities Article § 4-210 (d)(3)(ii).

customers. The STRIDE surcharge functions differently by permitting utilities to recover costs when they are incurred, even before they are in service. Because of this different treatment, the amounts reported the STRIDE filings that we rely on to make assumptions about future STRIDE investment are technically expenditures on STRIDE, not plant-in-service. Stated otherwise, the expenditure amounts that we use from the STRIDE filings are slightly different from the STRIDE plant-in-service numbers that would be used in a base rate proceeding. Because the timing difference between expenditures on STRIDE projects is usually just days or weeks (instead of months to years for large utility projects) this assumption has only *de minimus* impact on our overall results.

We next describe in more detail the STRIDE plans of each of Maryland's three major gas utilities.

2.1.1. BGE

BGE's STRIDE program is separated into two different sub-programs: Operation Pipeline and Service Replacement Program. The Operation Pipeline program consists of all original asset classes proposed in BGE's initial STRIDE plan: cast iron and bare steel main and bare steel and copper services. In 2016, BGE added the Service Replacement Program to specifically address pre-1970 3/4" high pressure steel services.

Table 2.3 summarizes the current long-term plans for BGE's STRIDE activities based on its most recent public filings. The projected remaining STRIDE expenditures for BGE were forecasted based on a combination of the plans for the remaining two years of the STRIDE II plan (2022 and 2023) and then a steady-state of 48 miles of main replaced each year from 2024 up until 2043, when only 38.2 miles will need to be replaced.[5] The remaining bare steel and copper services targeted through Operation Pipeline are assumed to be replaced as part of this main replacement work because BGE's cost estimates for main replacements include the cost of associated service replacement work.

BGE's estimated cost per mile from its STRIDE II plan is used as the cost basis for the annual budget. We increase the 2023 cost per mile ($2.63 million/mile) by three percent each year—the same assumption

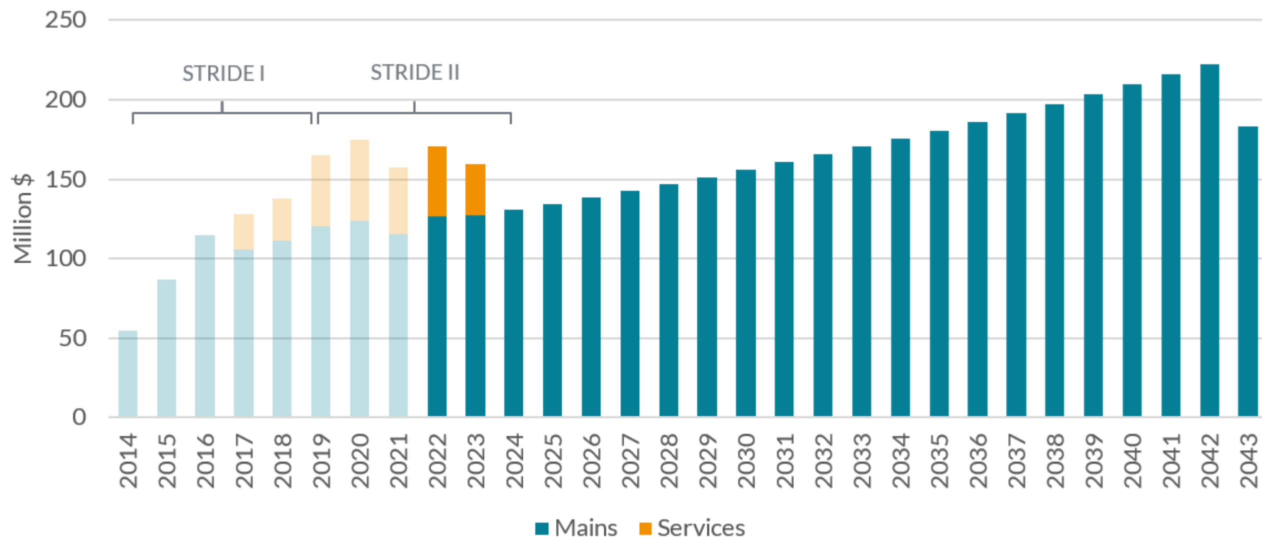
Table 2.3: BGE STRIDE Plans

Program	Asset types	Targeted Infrastructure (STRIDE II plan)	Current Status (2022)	Start Year	End Year
Operation Pipeline	Cast Iron Main	1,216 miles	1,016 miles	2014	2043
	Bare Steel Main	22 miles	14 miles	2014	2028
	Bare Steel Services	63,917 services	53,290 services	2014	2033
	Copper Services	20,251 services	15,600 services	2014	2043
Service Replacement Program	Pre-1970 ¾" High Pressure Steel Services	37,960 services	8,100 services	2016	2023

The "Targeted Infrastructure (STRIDE II)" column represents what was reported as remaining work on the system when BGE submitted its STRIDE II plan. The "Current Status" column provides updated information that accounts for the 2021 PHMSA Annual Report and supplemental information from STRIDE filings.

5 This plan uses a modified version of the projections that BGE presented for its accelerated STRIDE II plan in response to DR OPC 1-4 in CN 9468 that adjusts the number of miles replaced down from BGE's projections to the STRIDE II-approved level of 48 miles per year.

Figure 2.1: BGE STRIDE Investment Actual/Projections



BGE used in its STRIDE II plan—and multiplied by the assumed annual replacement miles to arrive at the estimated STRIDE costs. Figure 2.1 shows the projected STRIDE expenditures (2022–2043) along with STRIDE expenditures already incurred (2014-2021). The light-shaded years are historical (actual) investments while the dark-shaded bars are projections.

2.1.2. WGL

WGL's STRIDE program is unique in that it includes both distribution and transmission sub-programs. The STRIDE I plan was initially approved with a service-only program (Program 1) that was split into three components by service material and three main programs focused on specific pipe materials (Programs 2-4). The Commission subsequently approved another WGL distribution program (Program 5) that focused on three other distribution asset categories and five transmission programs.

WGL's initial plan for STRIDE I was to complete replacement of all targeted asset categories over 22 years—by the end of 2025. Despite the expansion of the programs within STRIDE and regular delays in completing work over the first five years of the program, WGL kept this same overall timeline in its STRIDE II plan. Table 2.4 summarizes the current long-term plans for WGL's STRIDE activities based on its most recent public filings.

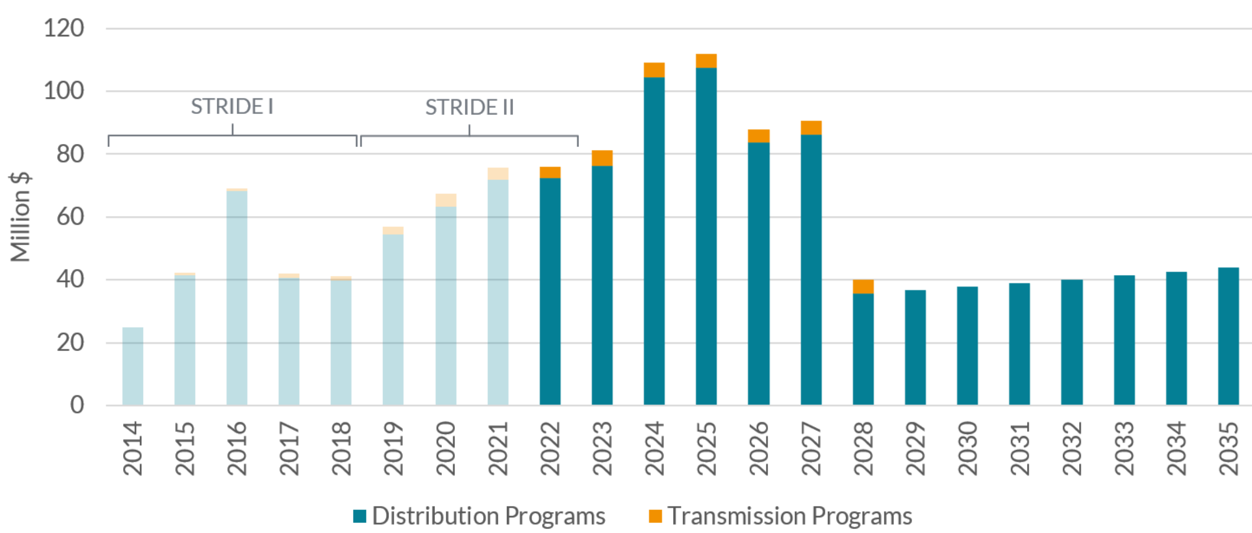
WGL did not provide updated projections of its distribution replacement activities through the end of STRIDE in the STRIDE II docket. Given the complexity created by the number of programs, a more simplistic estimation approach is required. Rather than attempting to develop assumptions for each program, the budget for each distribution program increases by three percent each year until the final year of the program. For example, the budget for Program 2 is $37.08 million in 2023 and is then estimated to be $38.2 million in 2024 (3% higher), and the budget for each year increases accordingly until 2027, the final planned year of the program. This approach effectively assumes that the replacement pace that WGL proposed for the final year of STRIDE II (2023) will continue for the duration of each program. We then added an additional 14.7% to the distribution budgets to account for

Table 2.4: WGL STRIDE Plans

Program	Asset Types	Targeted Infrastructure (STRIDE II plan)	Current Status (2022)	Start Year	End Year
Distribution 1A	Bare Steel / Unprotected Services	8,623 services	6,347 services	2014	2026
Distribution 1B	Copper Services	2,871 services	1,884 services	2014	2026
Distribution 1C	Pre-1975 Plastic Services	1,029 services	371 services	2014	2026
Distribution 2	Bare Steel / Unprotected Mains	124.5 miles	81.95 miles	2014	2028
Distribution 3	VMC Mains	392.7 miles	366.7 miles	2014	2035
	VMC Services	25,345 services	20,397 services	2014	2035
Distribution 4	Cast Iron Mains	56.1 miles	40.04 miles	2014	2035
Distribution 5A	Meter Build Up + Risers	113,000 risers	101,262 risers	2015	2035
Distribution 5B	Shallow Main	0.85 miles	0.24 miles	2015	2035
Distribution 5C	Steel Pressure Gauge Lines	1,725 gauge lines	1,194 gauge lines	2015	2035
Transmission 1	Transmission Mains	0 strips	--	--	--
Transmission 2	Remote Control Valves (RCV)	7 RCVs	Unknown	2015	2023
Transmission 3	Block Valves	10 valves	Unknown	2015	2023
Transmission 4	Valve Risers	7 valve risers	Unknown	2015	2019
Transmission 5	Replacements for Inline Inspection (ILI) Tools	3 strips	Unknown	2019	2025

The "Targeted Infrastructure (STRIDE II)" column represents what was reported as remaining work on the system when WGL submitted its STRIDE II plan. The "Current Status" column provides updated information that accounts for the 2021 PHMSA Annual Report and supplemental information from STRIDE filings.

Figure 2.2: WGL STRIDE Investment Actual/Projections



WGL's recent experience that has shown it has spent on average 14.7% more for the replacements completed over the first three years of STRIDE II.

WGL Witness Stuber provided estimates for the transmission programs through 2028 as part of the STRIDE II transmission plan. WGL has not experienced the same level of delays and cost overruns on its transmission projects, so these estimates were used as presented.

Figure 2.2 shows the projected STRIDE expenditures (2022–2035) along with STRIDE expenditures already incurred (2014-2021).

2.1.3. CMD

The STRIDE program that CMD is currently operating under remains relatively the same as the original program approved by the Public Service Commission in Case Number (CN) 9332. CMD's approved first five-year plan included an average replacement of 7.56 miles of bare steel or cast-iron main per year with an overall target to remove all bare steel and cast-iron main by the end of 2026.[6] For STRIDE II, CMD agreed to a settlement that set the annual replacement rate of bare steel and cast iron mains at eight miles per year. There was no update in CN 9479 on how this slight increase in replacement rate changed the anticipated STRIDE timeline, so the table below assumes that 2026 is still targeted to be the final year. Table 2.5 summarizes the current long-term plans for CMD's STRIDE activities based on its most recent public filings.

As shown in the table above, CMD has only a few years remaining under its current STRIDE program. At its current replacement pace, CMD will have approximately 17.5 miles of bare steel main to replace at the end of STRIDE II. However, we expect that CMD will need to replace more than 17.5 miles of pipe in the next iteration of its STRIDE plan. CMD's STRIDE projects in recent years have included replacement of high levels of non-leak prone material or "contingent" main that was connected to STRIDE targeted pipe.[7] For example, in 2021, CMD reported that it

Table 2.5: CMD STRIDE Plans

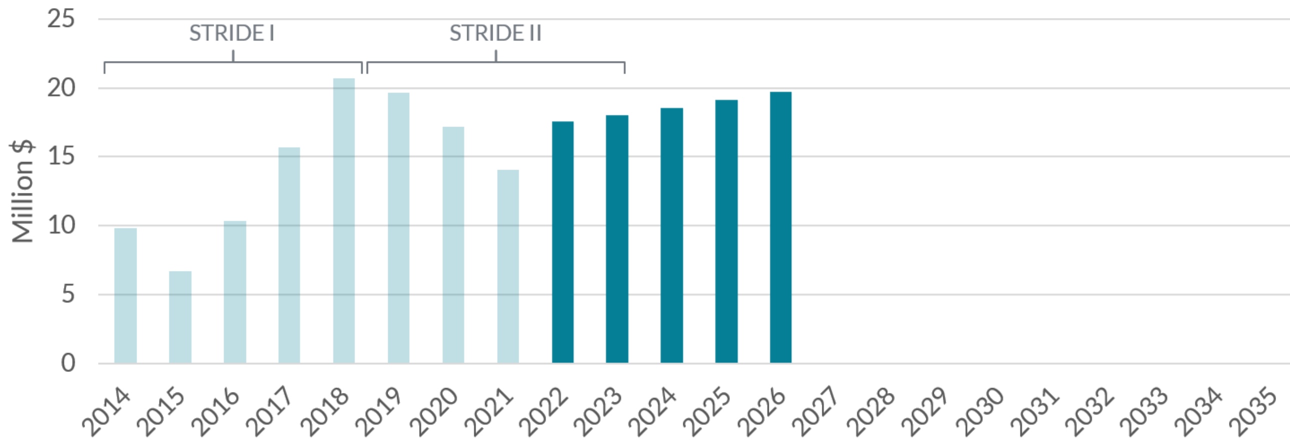
Program	Asset Types	Targeted Infrastructure (STRIDE II plan)	Current Status (2022)	Start Year	End Year
Infrastructure Replacement and Improvement Plan ("IRIS")	Bare Steel Services	3,027 services	1,521 services	2014	2026
	Bare Steel Mains	68.9 miles	33.5 miles	2014	Complete
	Cast/Wrought Iron Mains	2.2 miles	0.0 miles		

The "Targeted Infrastructure (STRIDE II)" column represents what was reported as remaining work on the system when CMD submitted its STRIDE II plan. The "Current Status" column provides updated information that accounts for the 2021 PHMSA Annual Report.

6 The approved plan was CMD's second attempt to receive approval of its first five year STRIDE plan. The Commission denied CMD's initial proposal in CN 9332 to replace 5.9 miles of bare steel and cast-iron mains per year from 2014 to 2018 because it found that the replacement rate did not represent a material acceleration over its current pace.

7 When companies replace materials such as bare steel and cast iron mains that are targeted for removal through STRIDE, there are times when other pipe materials, such as coated steel or plastic mains, are encountered. This other material may be a section of pipe that was previously installed to repair a leak. Companies argue that for efficiency reasons it is more expedient to replace the entire strip of pipe rather than work around the material not targeted for STRIDE. This pipe is commonly called "contingent" main.

Figure 2.3: CMD STRIDE Investment Actual/Projections



had to replace 18.4 miles in total to retire 8.4 miles of bare steel main. Due to the additional costs of removing these 10.1 miles, CMD completed four projects outside of STRIDE (*i.e.*, it is not recovering the costs through the surcharge) in order to complete the eight miles within the budget agreed upon in the CN 9479 settlement. This recent trend of significant "contingent main replacement" led us to assume that the total investment for CMD's final STRIDE years will include more than just the 17.5 miles of bare steel. For the 2024-2026 investment projections, we assume that CMD will continue its same replacement pace of 8 miles per year.[8] At that pace, 17.5 miles of main will be replaced along with 6.5 miles of contingent main. The budget is calculated by using the cost per mile ($2.2 million per mile) used for 2023 grown by three percent each year.

Figure 2.2 shows the projected STRIDE expenditures (2022–2026) along with STRIDE expenditures already incurred (2014-2021).

2.2. Non-STRIDE Capital Projections

We separately analyzed the gas utilities' capital investments made outside of STRIDE (*i.e.*, "non-STRIDE" investments). Unlike STRIDE expenditures for which utilities must file five-year plans, no statute or PSC action requires gas utilities to publicly disclose their long-term capital expenditure plans outside of a rate case.

This analysis thus began by first attempting to understand the amounts of investments each of the utilities have made outside of STRIDE in recent years. The projections for future non-STRIDE investments are based on the recent historical trend. We gathered the most recent data on plant additions available for each company. For WGL and CMD, this includes the three most recent annual reports submitted to the Maryland PSC.[9] For BGE, this includes the capital plans submitted in its three-year MYRP. These numbers were then tied to the annual STRIDE investments made in the same year to arrive at an estimate

8 Note that initial iterations of the CMD projections had assumed CMD's STRIDE plan would operate through 2030.

9 For CMD, we used the annual reports filed for years 2019-2021. For WGL, we used years 2018-2021 as WGL's 2021 annual report was unavailable at the time we conducted our analysis.

Table 2.6: Non-STRIDE Investments of Maryland's Three Largest Gas Utilities, 2022-2100 (million $)

	BGE	WGL	CMD	
Non-STRIDE Year 1	$255.90	$116.00	$8.21	
Non-STRIDE Year 2	$284.89	$107.51	$4.70	
Non-STRIDE Year 3	$249.00	$84.04	$19.18	
Three-Year Average	$263.26	$102.52	$10.70	**THREE-COMPANY FUTURE NON-STRIDE TOTAL**
Estimated Non-STRIDE Spend 2022-2100	$20,805.14	$8,098.74	$844.98	$29,749 million

for non-STRIDE investments.[10] Specifically, for each company, we identified the amount of non-STRIDE investments made as the difference between total plant additions and the STRIDE additions. This is represented by the following formula:

Non-STRIDE Additions =
Total Utility Plant Additions — Stride Additions

Once we identified the historical non-STRIDE additions, the next step was to decide what should be used as the assumed rate of future non-STRIDE additions to capital plant. Two possibilities were considered:

Compound. A recent phenomenon in the gas industry is that utility plant-in-service balances are experiencing compound growth each year. Compound growth means that plant grows at a constant rate. This result requires that plant investment levels increase each year. For example, consider a utility with $1 billion in plant-in-service that makes $100 million in investments. This amount represents a 10 percent increase in plant-in-service. If that utility were then to make a $100 million investment the next year, the annual growth would only be 9.09 percent.[11] To maintain the same 10 percent annual growth in plant-in-service, the amount of additions would instead need to increase to $110 million. One option we considered for estimating non-STRIDE investments was to assume that the level of non-STRIDE investments would be the amount needed to maintain the compound annual growth rate (CAGR) demonstrated over the three-year period between December 31, 2017, and December 31, 2020.

Straight-line. The other approach we considered was to assume that investments outside STRIDE would remain at the same recent levels in perpetuity. We calculated the three-year average level of non-STRIDE additions and then used the result as the constant level of annual future investments. This was called our "straight-line" estimate.

We decided to use the more conservative straight-line assumption for estimating non-STRIDE investments. The compound approach resulted in extremely high levels of investment in the future that did not seem realistic. The straight-line assumptions are likely more realistic but are notably conservative, given that we do not add to the amount each year to account for inflation.

10 As explained earlier, the historical STRIDE amounts relied on in this report are expenditures, not plant-in-service. The utility plant additions reported in the annual reports are plant-in-service numbers. The consequence of this assumption is that our non-STRIDE capital additions here are understated because actual STRIDE plant-in-service is less than STRIDE expenditures.

11 $1.1 billion + $0.1 billion / $1.1 billion -1 = 9.09%

The subsections below describe any unique assumptions that needed to be made for each company and then present the estimate of the non-STRIDE investment amount used in the capital projections.

2.2.1. BGE

BGE is currently operating under a multiyear rate plan (MYRP) from 2021 to 2023. We derived the estimate for non-STRIDE investments by using the capital plan submitted in compliance with the Commission's decision in CN 9645. Table 2.7 presents the derivation of the non-STRIDE capital investment assumption that is used to determine the average annual in the BGE capital projections.

The combined investment projections for BGE, starting after the MYRP in 2024, represent the STRIDE projections through 2045 plus a base level of $263.26 million that we maintain for the entire evaluation period. Figure 2.4 shows the results of our capital investment projections for BGE through 2100.

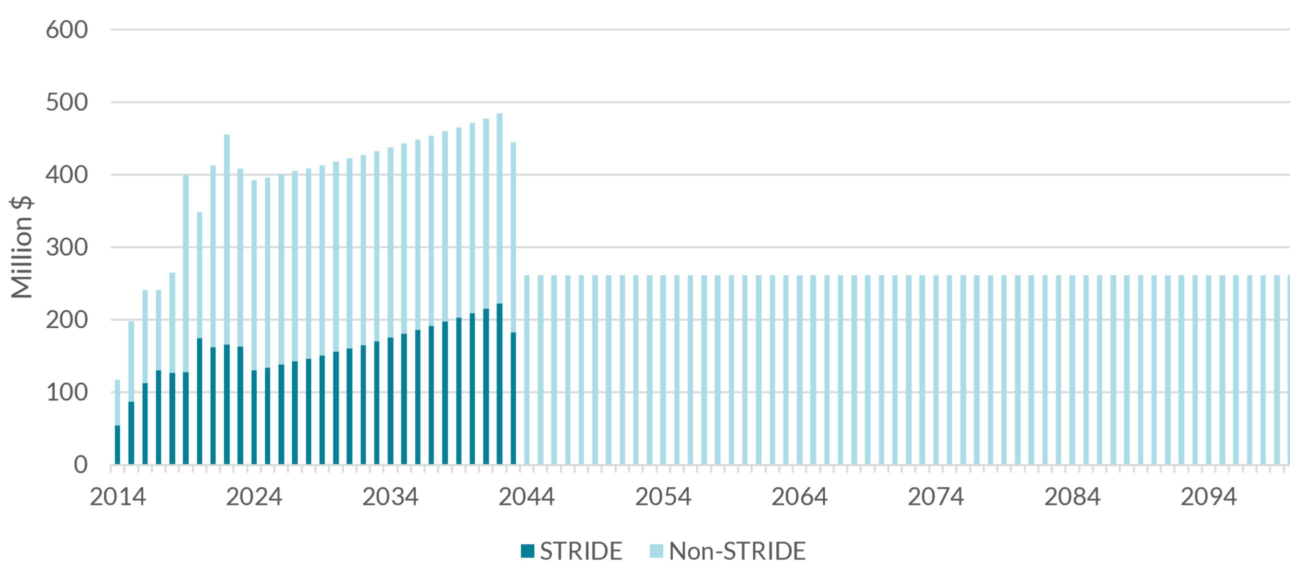
Table 2.7: BGE Non-STRIDE Investment Projections

Line	Description	Source	Projection
1	Plant Additions (2021-2023)	CN 9645, MYRP	$1,277 million
2	STRIDE Plant Addition (2021-2023)	STRIDE filings	$487.4 million
3	Non-STRIDE Plant Additions (2021-2023)	Line 1 – Line 2	$789.8 million
4	Average Annual Non-STRIDE Additions	Line 3 / 3	$263.26 million

2.2.2. WGL

The same approach was used to develop the non-STRIDE capital projections for WGL with two exceptions. First, WGL uses its FERC Form 2 as the basis of its annual report. The problem this reporting creates is that the FERC Form 2 encompasses WGL's operations in Maryland, Virginia, and the District of Columbia, which means that much of the information in WGL's annual report is an aggregate of its three service jurisdictions. While there are Maryland specific entries that identify the number of customers and revenue earned within the Maryland division,

Figure 2.4: BGE Annual Capital Investment Actual/Projections



there is no disaggregation of utility plant or operating expenses by division. This meant that we needed to make assumptions about what amount of utility plant and the utility plant additions were associated with WGL's Maryland division.[12] Second, because WGL is not operating under a MYRP, the beginning of our projections is 2021, the year after the most recently filed annual report.

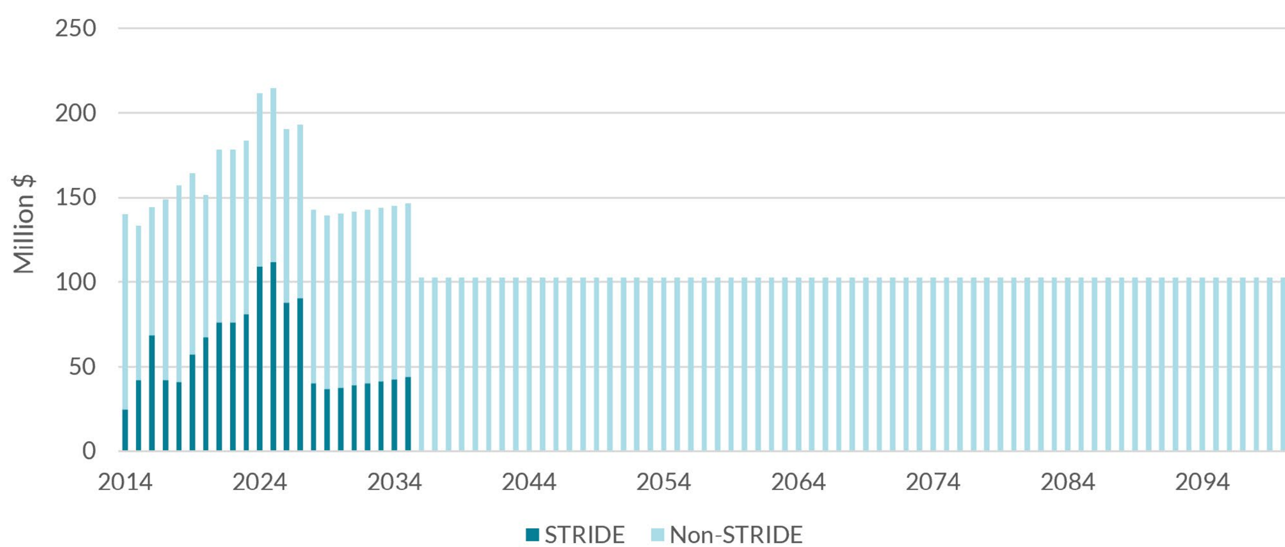
We used WGL's allocated cost-of-service study submitted in its 2020 base rate case (CN 9651) to identify a jurisdictional plant allocation factor to use for assigning a portion of plant additions to Maryland. Table 2.8 presents the derivation of the non-STRIDE capital investment assumption that is used in the WGL capital projections.

The combined investment projections for WGL, starting in 2021, represent the STRIDE projections through 2035 plus a base level of $102.5 million that we maintain for the entire evaluation period. Figure 2.5 shows the results of our capital investment projections for WGL through 2100.

Table 2.8: WGL Non-STRIDE Investment Projections

Line	Description	Note	Projection
1	Total WGL Plant Additions (2018-2020)	Annual Reports	$1,238 million
2	MD Plant Allocator	CN 9651, Exh. RET-6	38.2%
3	Estimated MD Plant Additions	Line 1 * Line 2	$473.1 million
4	STRIDE Plant Addition (2018-2020)	STRIDE filings	$165.6 million
5	Non-STRIDE Plant Additions (2018-2020)	Line 3 – Line 4	$307.5 million
6	Average Annual Non-STRIDE Additions	Line 3 / 3	**$102.5 million**

Figure 2.5: WGL Annual Capital Investment Actual/Projections



12 This decision to use an approximation for the WGL plant in service numbers means that even the historical numbers on revenue requirement and total investments for WGL are estimates.

2.2.3. CMD

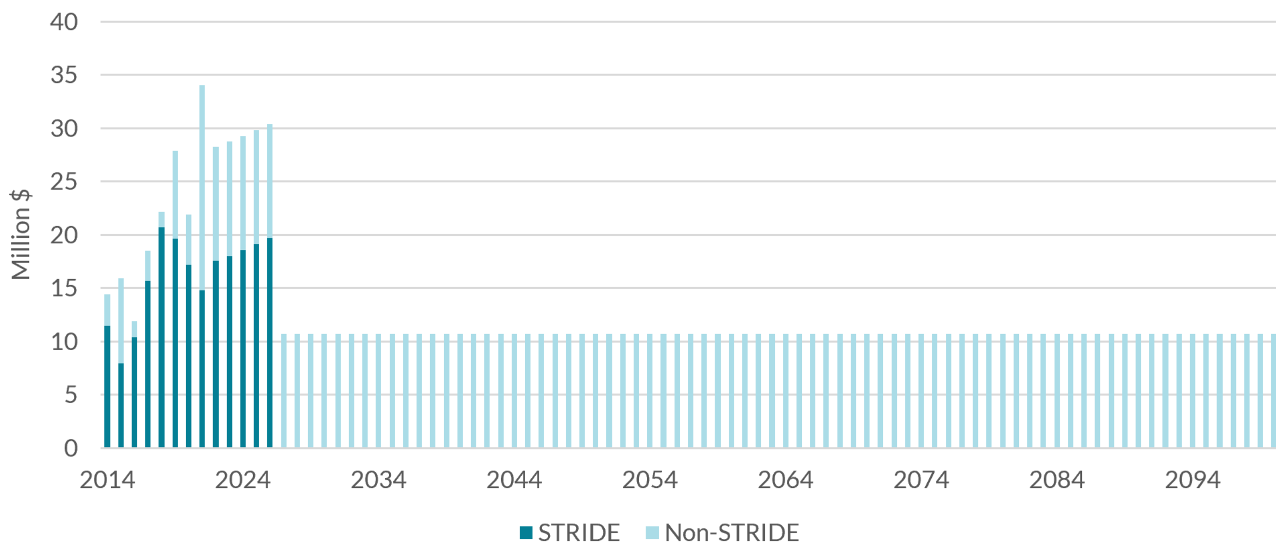
Like we did for WGL, to identify CMD's non-STRIDE investment amounts, we began by looking at its historical investment amounts in the three most recent annual reports. Table 2.9 presents the derivation of the non-STRIDE capital investment assumption that is used in the CMD capital projections.

The combined investment projections for CMD, starting in 2021, represent the STRIDE projections through 2026 plus a base level of $10.7 million that we maintain for the entire evaluation period. Figure 2.5 shows the results of our capital investment projections for CMD through 2100.

Table 2.9: CMD Non-STRIDE Investment Projections

Line	Description	Note	Projection
1	Plant Additions (2019-2021)	Annual Report	$83.75 million
2	STRIDE Plant Addition (2019-2021)	STRIDE filings	$51.66 million
3	Non-STRIDE Plant Additions (2019-2021)	Line 1 – Line 2	$32.09 million
4	Average Annual Non-STRIDE Additions	Line 3 / 3	$10.7 million

Figure 2.6: CMD Annual Capital Investment Actual/Projections



SECTION THREE

ANNUAL REVENUE REQUIREMENT PROJECTIONS

This section both describes the approach we took to estimating the revenue requirements related to our capital investment projections and discusses some of the results of this analysis. We begin, in Section 3.1, with an overview of our revenue requirement modeling approach used to project annual revenue requirements. The remaining four parts of this section include a summary of the annual STRIDE revenue requirements calculated using the revenue requirement model (3.2), a summary of the total STRIDE and non-STRIDE capital revenue requirements calculated using the model (3.3), an explanation of how the operating cost component of the annual revenue requirement was calculated (3.4), and the results of the annual revenue requirement projections for each company (3.5).

3.1. Revenue Requirement Model

To understand the impact of our capital investment projections on rates, we first developed a revenue requirement model that estimated the capital-related components of the annual revenue requirement. This model was a modified version of the model used in the testimony we prepared for OPC on BGE's STRIDE II plan in PSC Case No. 9479.

The revenue requirement for the capital investment components included:

- Return on Rate Base
- Depreciation
- Property Taxes
- Gross-up for income taxes, bad debt, franchise taxes, and PSC assessment.

To calculate the annual revenue requirement in future years, we needed to develop certain assumptions on depreciation, retirements, cost of capital, property taxes, and the gross-conversion factor. We relied on a mix of STRIDE filings and annual reports to develop the assumptions. Table 3.1 presents the various assumptions used to calculate the capital-related revenue requirements for each company.

These assumptions are based on the best information we were able to identify that is publicly available. The assumptions may not represent what BGE's own internal records show today, and actual numbers will differ from those generated using our assumptions. The analysis is solely intended to show the general impact that current capital investment trends will have on future revenue requirements and therefore utility customer rates; it does not identify the precise future revenue requirements that will be developed through the regulatory process.

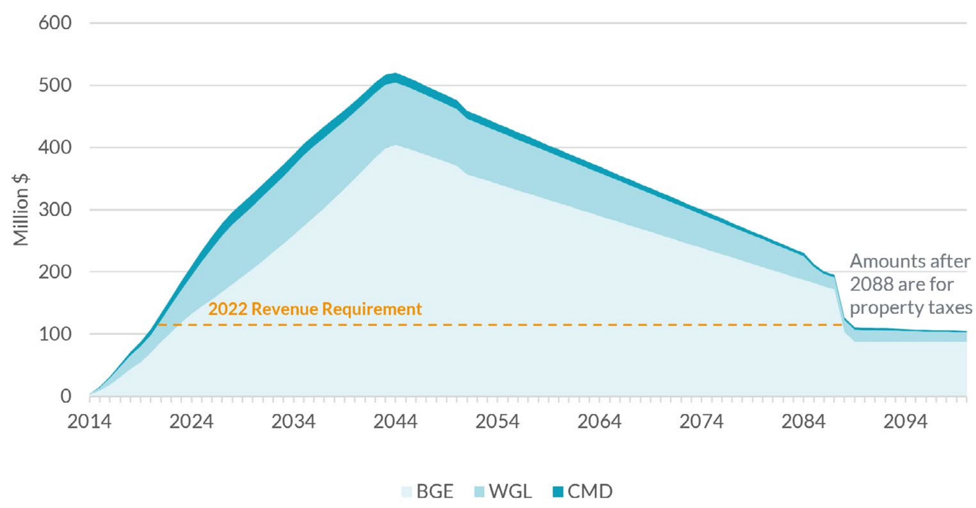
Table 3.1: CAPEX Revenue Requirement Assumptions

	BGE	WGL	CMD
Depreciation Rates	1.76% (mains) 3.54% (services) 2.76% (non-STRIDE)	1.65% (distribution) 1.91% (transmission) 2.42% (non-STRIDE)	1.8% (STRIDE) 2.35% (non-STRIDE)
Retirement Rate	-3.11% (mains) -1.36% (services) -2.50% (non-STRIDE)	-2.5%	-5.0% (STRIDE) -2.5% (non-STRIDE)
Weighted Average Cost of Capital	6.33%	7.09%	7.16%
Gross-Conversion Factor	70.87%	72.48%	70.35%
Property Tax Rate	1.23%	1.12%	1.23%
Tax Treatment of STRIDE Plant Additions	Tax Repairs: 80% MACRS: 20%	Tax Repairs: 80% MACRS: 20%	Tax Repairs: 80% MACRS: 20%

3.2. STRIDE Revenue Requirement

The pyramid figure below was made using the annual revenue requirement approach described in the previous section. What makes this figure informative is that it provides context for where we currently are in the overall STRIDE plans. As identified by the arrow and dotted line, the combined 2022 revenue requirement of approximately $165 million across the three STRIDE programs represents a fraction, 30 percent, of the $524 million peak in annual STRIDE revenue requirements that we project for 2044. In other words, if STRIDE plans continue as currently constituted, then Maryland customers will eventually be paying more than **three times** for STRIDE investments than they are paying today.

Figure 3.1: STRIDE Annual Revenue Requirement Pyramid



Maryland customers will eventually be paying more than **three times** for STRIDE investments than they are paying today.

3.3. Non-STRIDE Revenue Requirement

The STRIDE revenue requirement in Figure 3.1 represents only a fraction of the capital-related annual revenue requirements customers will need to pay to cover for capital investments over the next 80 years. The STRIDE and non-STRIDE capital additions we project through 2100 would result in a combined annual capital revenue requirement for the three utilities exceeding $1.5 billion dollars by 2043 or 2.3 times the combined $667 million in capital revenue requirements customers are paying through rates in 2022. Put another way, customers today are responsible for paying less than half of the capital costs that customers will be responsible for in 2043. Figure 3.2 provides both a comparison of the combined non-STRIDE (dark teal) and STRIDE (light teal) annual capital revenue requirements across the combined three companies and shows how the total annual capital revenue requirements (dark teal + light teal) will evolve over time.

Customers today are responsible for paying **less than half** of the capital costs that customers will be responsible for in 2043.

3.4. Operating Costs Revenue Requirement

Until now, this revenue requirement section has only considered capital-related components. To develop rate projections, we needed to develop assumptions for the level of operating costs included in the annual revenue requirement. Operating cost estimates for the projection period were "reverse-engineered" using a combination of our estimated capital component revenue requirements and the base revenue requirements from the companies' most recent base rate filings. We used the sum of the base distribution revenue requirement and STRIDE revenue requirement from each company's most recent rate

Figure 3.2: Combined Three-Company STRIDE and Non-STRIDE Revenue Requirement

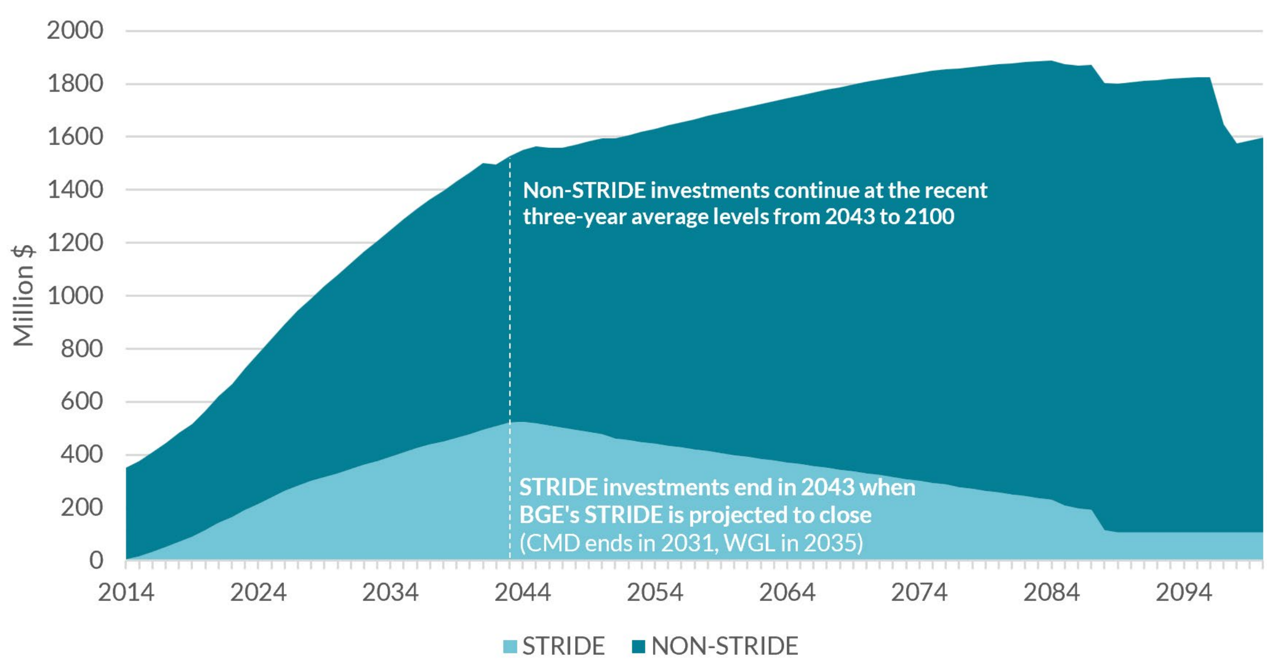


Table 3.2: Operating Cost Revenue Requirement Assumptions

	BGE (CN 9646, Year 3)	WGL (CN 9651)	CMD (CN 9644)
Revenue Requirement	$651.96 million	$377.19 million	$42.30 million
Estimated Capital Revenue Requirement	$423.65 million	$254.08 million	$29.44 million
Operating Revenue Requirement	$228.31 million	$123.11 million	$12.87 million

proceeding and then subtracted our estimated capital revenue requirement to arrive at the estimated operating portion of the revenue requirement. This process is shown in Table 3.2.

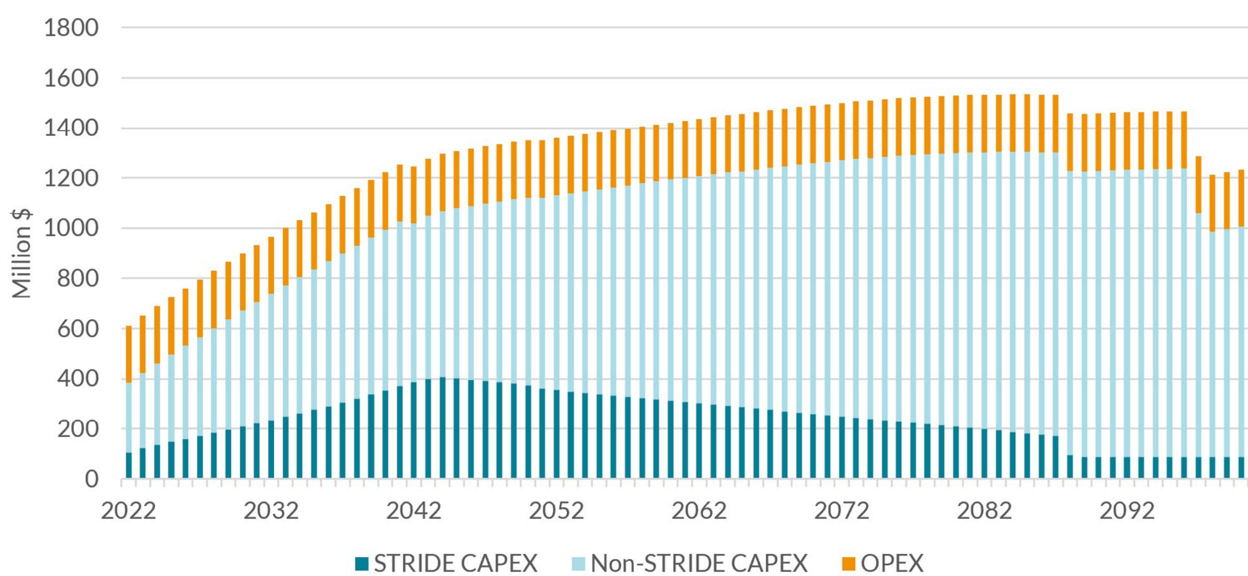
We should emphasize here that we adopt the same operating cost assumptions for every year in the evaluation period; there is no markup for inflation. This approach is consistent with our choice to not grow the non-STRIDE capital investment amounts over time. What this means is that the revenue requirements are in nominal 2022 dollars.[13]

3.5. Annual Revenue Requirement Results

The combination of our STRIDE and non-STRIDE capital revenue requirements and operating expenses represents our annual revenue requirement projections for each company.

Figure 3.3 presents the results of the BGE annual revenue requirement projections. The BGE revenue requirement is projected to peak in 2084 when it reaches $1.532 billion or 2.3 times the revenue requirement of the third year of its current MYRP.

Figure 3.3: BGE Annual Revenue Requirement Projections



13 STRIDE investment assumptions do inherently include inflation to the degree that the companies' cost projections include inflation.

Figure 3.4 presents the results of the WGL annual revenue requirement projections. The WGL annual revenue requirements continue to grow over the evaluation period with no peak and drop like BGE. There is no peak and drop because WGL currently makes more non-STRIDE investments than STRIDE investments. Because WGL's non-STRIDE investments are greater, even when STRIDE ends, WGL is projected to continue making substantial investments. BGE and CMD are currently making a majority of their annual investments through STRIDE such that when STRIDE ends, there is a drop to the baseline non-STRIDE investments. Should WGL's investment follow our assumptions, then rate base would almost double over the next 80 years.

Figure 3.5 presents the results of the CMD revenue requirement projections. CMD's revenue requirements have periodic drops over the evaluation period as STRIDE investments become fully depreciated, but overall the revenue requirement continues to increase over the entire period.

Figure 3.4: WGL Annual Revenue Requirement Projections

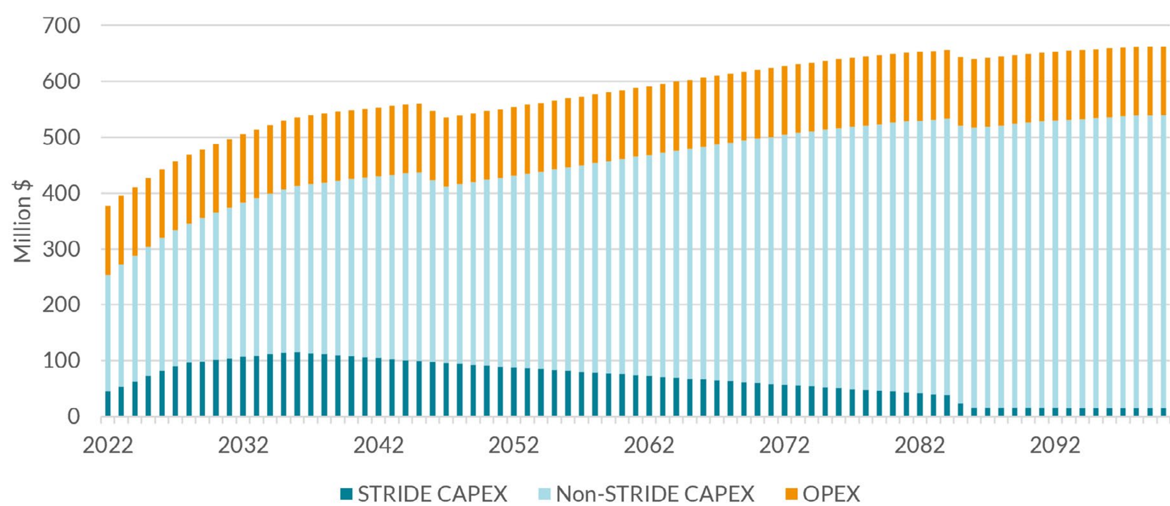
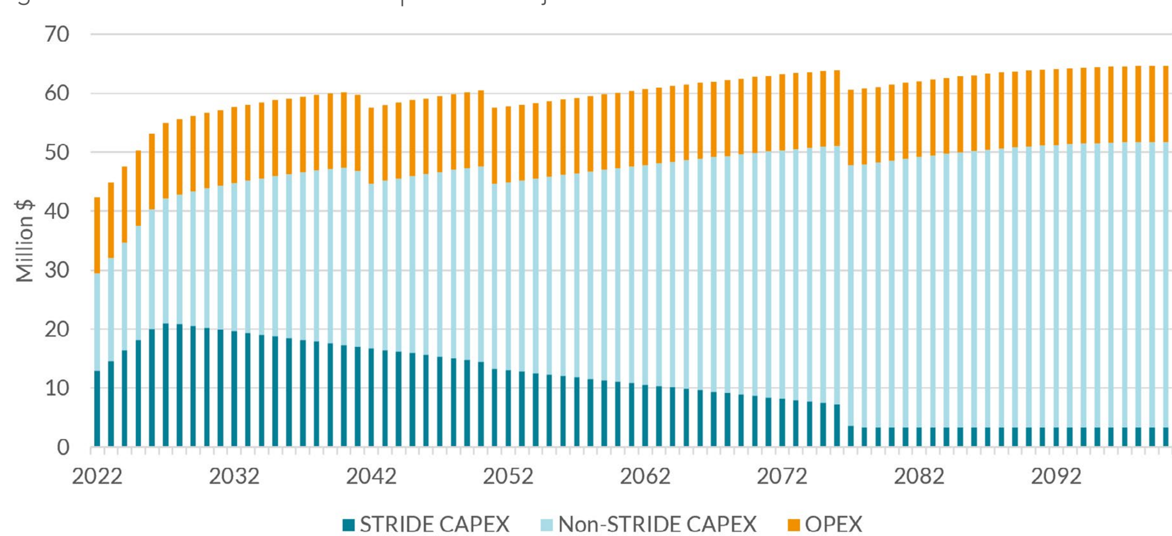


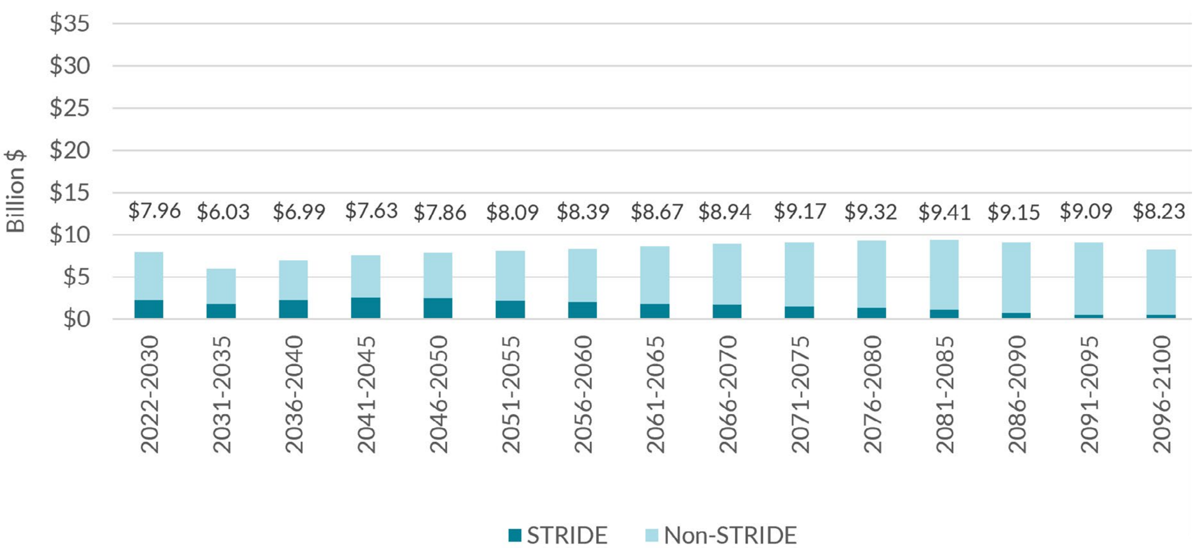
Figure 3.5: CMD Annual Revenue Requirement Projections



The figures above represent the annual amounts that we estimate Maryland's gas customers are expected to be asked to pay from 2022 through 2100. As illustrated in Figure 3.6, total revenues to be collected from customers over this 79-year period across all three companies are estimated to be $125 billion. From 2022-2045, Maryland gas customers will be asked to spend $28.61 billion total.

Total revenues to be collected from customers to pay for capital investments over this 79-year period across all three companies are estimated to be **$125 billion**.

Figure 3.6: Projected Gas Customer Payments toward CAPEX (billion $), 2022-2100



SECTION FOUR

RATE IMPACTS

The annual revenue requirement projections—sum of capital and operating cost estimates—described in Section 3 were used to prepare estimates of typical customer bills. This step was done by allocating revenue to the residential heating class of each company using the revenue allocation factors from the most recent STRIDE filings. The billing determinants for customer-months and usage were set based on the revenue proofs in the compliance filing adopting the rates set in the most recent base rate case for each company. It is assumed that the number of customers and sales remain constant over the evaluation period. Stated otherwise, the projections do *not* account for any migration of gas customers to electric as a result of electrification policies or through endogenous migration.

For each year, we allocate the revenue requirement to the residential heating class and then design rates to recover this revenue target. Rate design follows a three-step process:

- First, the STRIDE surcharge is set as a fixed monthly surcharge to recover the "new" or incremental STRIDE revenue requirement for the year. This distinction is possible because the STRIDE and non-STRIDE capital revenue requirements are calculated separately. Put another way, the target STRIDE revenue for any given year (Year n) is the difference between the cumulative STRIDE revenue requirement for Year n minus the cumulative STRIDE revenue requirement for the previous year (Year n-1). This approach is meant to mimic the "rolling" in of STRIDE into base rates over time.
- Next, a Fixed Charge is set. The Fixed Surcharge starts at current level (or 2023 level for BGE) and is then increased by 1 percent each year.
- Finally, all remaining revenue requirement assigned to the residential classes is collected through the volumetric charge.

Table 4.1: Rate Design and Bill Determinant Assumptions

	BGE (CN 9645)	WGL (CN 9651)	CMD (CN 9644)
Customer Class	Schedule D (Residential)	Residential Heating/Cooling	RS (Residential Service)
Residential Revenue Allocation %	66.5%	69.5%	57.3%
Customer-months	7,886,947	5,470,633	367,106
Sales (therms)	445,102,435	358,972,754	23,750,943
Starting Fixed Charge	$15.25	$11.55	$16.00

Customer-months are the number of bills sent out in a year. This is equal to the number of customers x 12.

We follow the above approach to estimate volumetric and fixed charges for residential customers from 2022 to 2100. To present these results, in the subsections below, we show the monthly bill for a typical customer in winter months. Our typical customer uses 160 therms per month in January or February.[14] The next three subsections provide the results of this typical customer bill analysis for each company.

4.1. BGE

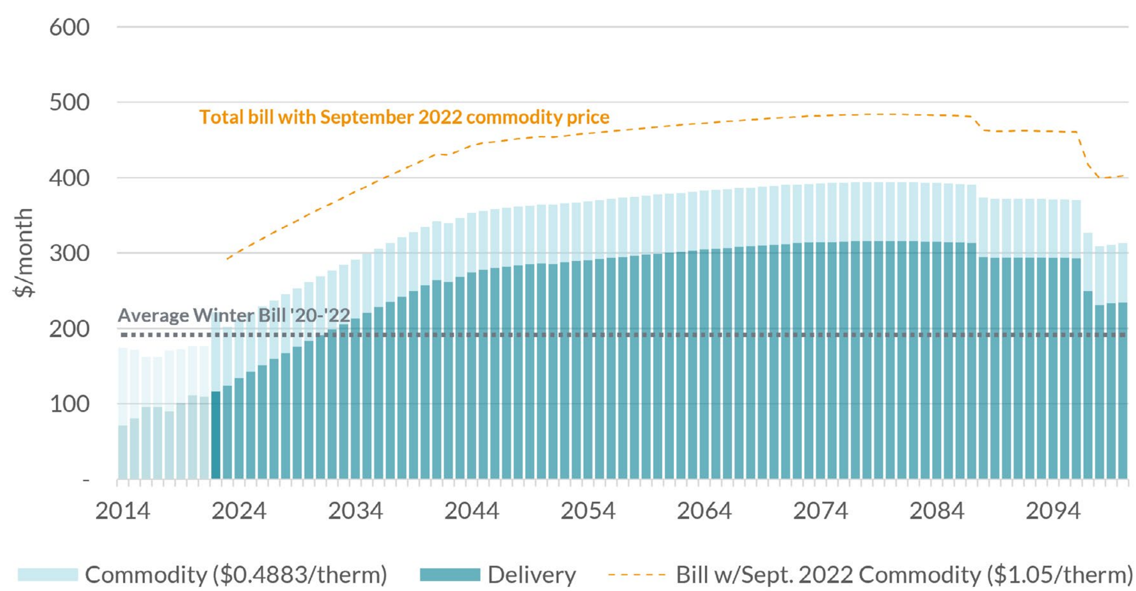
The bill for the typical BGE customer includes both the cost of delivery (fixed base charge, volumetric base charge, STRIDE surcharge) and commodity. Before calculating the typical bill, we needed to develop an assumption for the commodity portion of the bill.

The commodity price we use in the BGE bill analysis is based on the average commodity price charged to BGE's residential customers in the five proceeding Februarys (2018-2022). For reference, and to provide context for the current jump in natural gas prices, we also show what the future BGE bill would be if prices remain at the September 2022 levels.[15] The commodity price assumptions are shown in Table 4.2.

Table 4.2: BGE Commodity Price Assumptions

Scenario	Definition	Price ($/therm)
Base Commodity	5-year February commodity average	0.4884
Current Commodity	September 2022 commodity price	1.0500

Figure 4.1: BGE Typical Winter Bill, 2014-2100



BGE rates for 2021 and 2022 include the Rider 18 offset that was adopted to lower bills in the first two years of the MYRP. This offset amount is removed after 2022.

14 This assumption is based on the average residential gas usage per customer in Maryland for January and February over the last five years. According to the Energy Information Agency (EIA), residential gas consumption in Maryland in the months of January and February has averaged 155.6 million therms for these two months from 2018 to 2022. For the approximately 965,000 residential gas customers in Maryland, this results in an average of 161.17 therms per customer in these two winter months. We round this result to 160 therms for our bill impact analysis.

15 ML#242191 (BGE September 2022 Gas Commodity Price)

The estimated winter bill for a BGE customer from 2022 to 2100 is presented in Figure 4.1. Our projections show that if BGE continues investing in capital at the projected levels, the typical winter bill for a customer using 160 therms/month will grow from an average of $192 in 2020-2022 to $299, a 56 percent increase by 2035, and $364, a 90 percent increase by 2050. These estimates assume commodity prices revert back to the five-year averages. If gas prices stay around the current (2021-2022) levels, then the typical residential customer's winter bill would increase by an additional $89.86 per month.

4.2. WGL

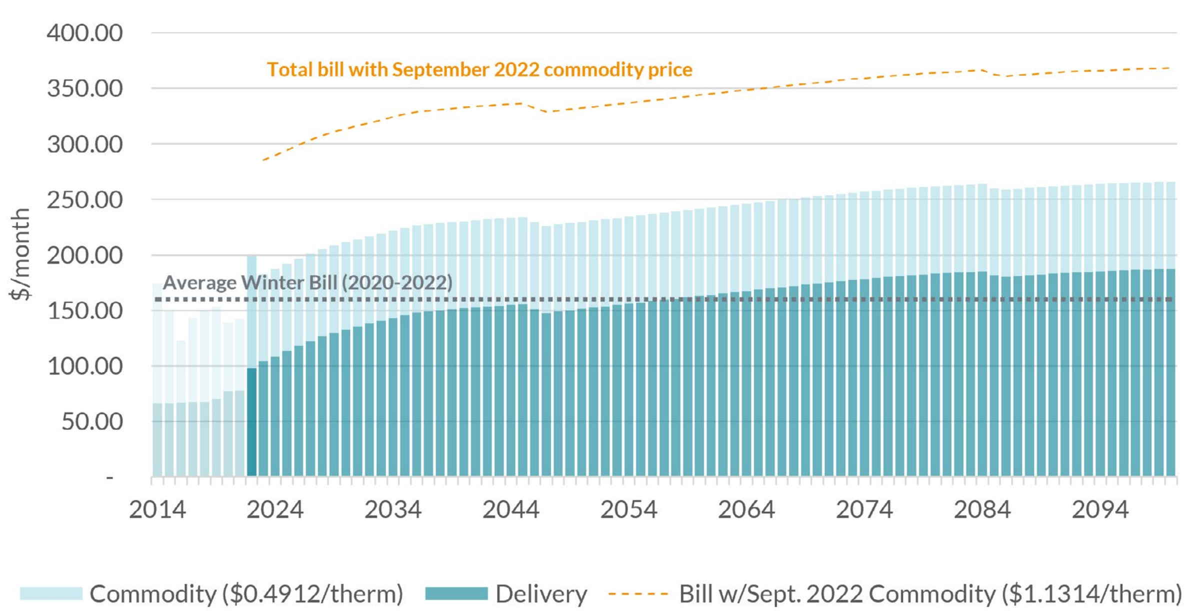
The commodity prices we use in the WGL bill analysis is based on the average commodity price charged to WGL's residential customers in the five proceeding Februarys (2018-2022). For reference, and to provide context for the jump in natural gas prices in 2022, we also show what the future WGL bill would be if prices remain at their current levels. These commodity price assumptions[16] are shown in Table 4.3.

Table 4.3: WGL Commodity Price Assumptions

Scenario	Definition	Price ($/therm)
Base Commodity	5-year February commodity average	0.4912
Current Commodity	September 2022 commodity price	1.1314

The estimated winter bill for a WGL customer from 2022 to 2100 is presented in Figure 4.2. Our projections show that if WGL continues investing in capital at the projected levels, the typical winter bill for a customer using 160 therms/month will grow from an average of $160 in 2020-2022 to $224, a 40 percent increase by 2035, and $230, a 44 percent increase by 2050. If gas commodity prices stay around the September 2022 level, the typical residential customer's winter bill would increase by an additional $102.43 per month.

Figure 4.2: WGL Typical Winter Bill, 2014-2100



16 ML#241971 (WGL September-October 2022 Purchased Gas Charge).

4.3. CMD

The commodity prices we use in the CMD bill analysis is based on the average commodity price charged to CMD's residential customers in the five proceeding Februarys (2018-2022). For reference, to provide context for the jump in natural gas prices in 2022, we also show what the future CMD bill would be if prices remain at their current levels.[17] The commodity price assumptions are shown in Table 4.4.

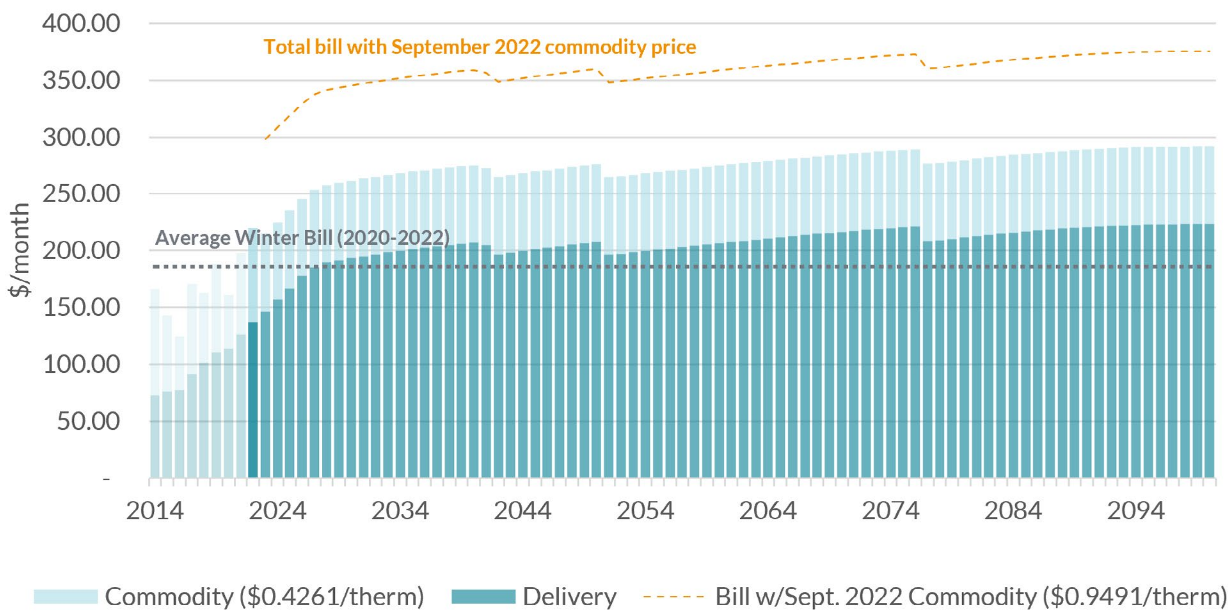
The estimated winter bill for a CMD customer from 2022 to 2100 is presented in Figure 4.1. Our projections show that if CMD continues investing in capital at the projected levels, the typical winter bill for a customer using 160 therms/month will grow from an average of $186 in 2020-2022 to $270, a 45 percent increase by 2035, and $276, a 48 percent increase by 2050. If gas commodity prices stay around the current (September 2022) levels, the typical residential customer's winter bill would increase by an additional $83.69 per month.

Table 4.4: CMD Commodity Price Assumptions

Scenario	Definition	Price ($/therm)
Base Commodity	5-year February commodity average	0.4261
Current Commodity	September 2022 commodity price	0.9491

The average CMD customer's winter bill will increase 45% by 2035.

Figure 4.3: CMD Typical Winter Bill, 2014-2100



17 ML#241226 (CMD September 2022 Gas Commodity Price)

SECTION FIVE

OTHER GAS UTILITY COST ANALYSIS

In addition to the core analysis of developing capital cost projections and estimating the bill impact, we performed other analysis for OPC on STRIDE-related issues. The six subsections below discuss the results.

5.1. Recovery of STRIDE Costs

We determined the portion of the total STRIDE costs that have already been recovered through rates and, conversely, what portion of the STRIDE costs remain to be recovered. An investment is being "recovered" through rates until it is fully depreciated. Utilities under rate-of-return regulation receive a "return on" the undepreciated value of an investment, in the form of a return on equity, and a "return of" the investment, in the form of depreciation expenses. Accordingly, we use cumulative STRIDE depreciation to represent the amounts "recovered" through rates.

The purpose of this exercise is to review the overall rate recovery progress, *i.e.*, progress toward the recovery of all completed and planned STRIDE costs. This meant that we defined the "unrecovered" portion of STRIDE in each year as the sum of the undepreciated completed plant and any remaining STRIDE investment not yet completed.

Figure 5.1: Percentage of STRIDE Costs Remaining to be Recovered by Company

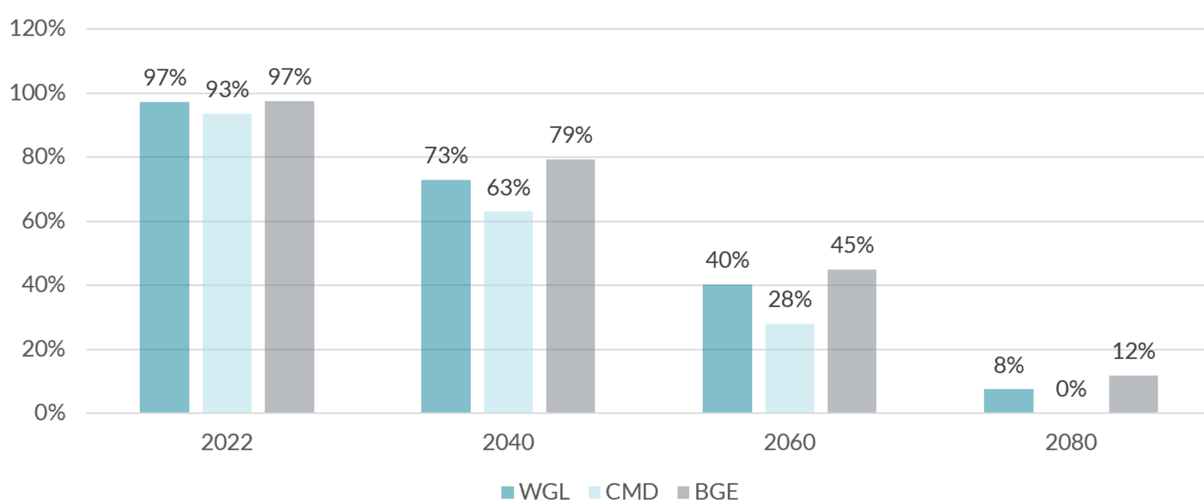


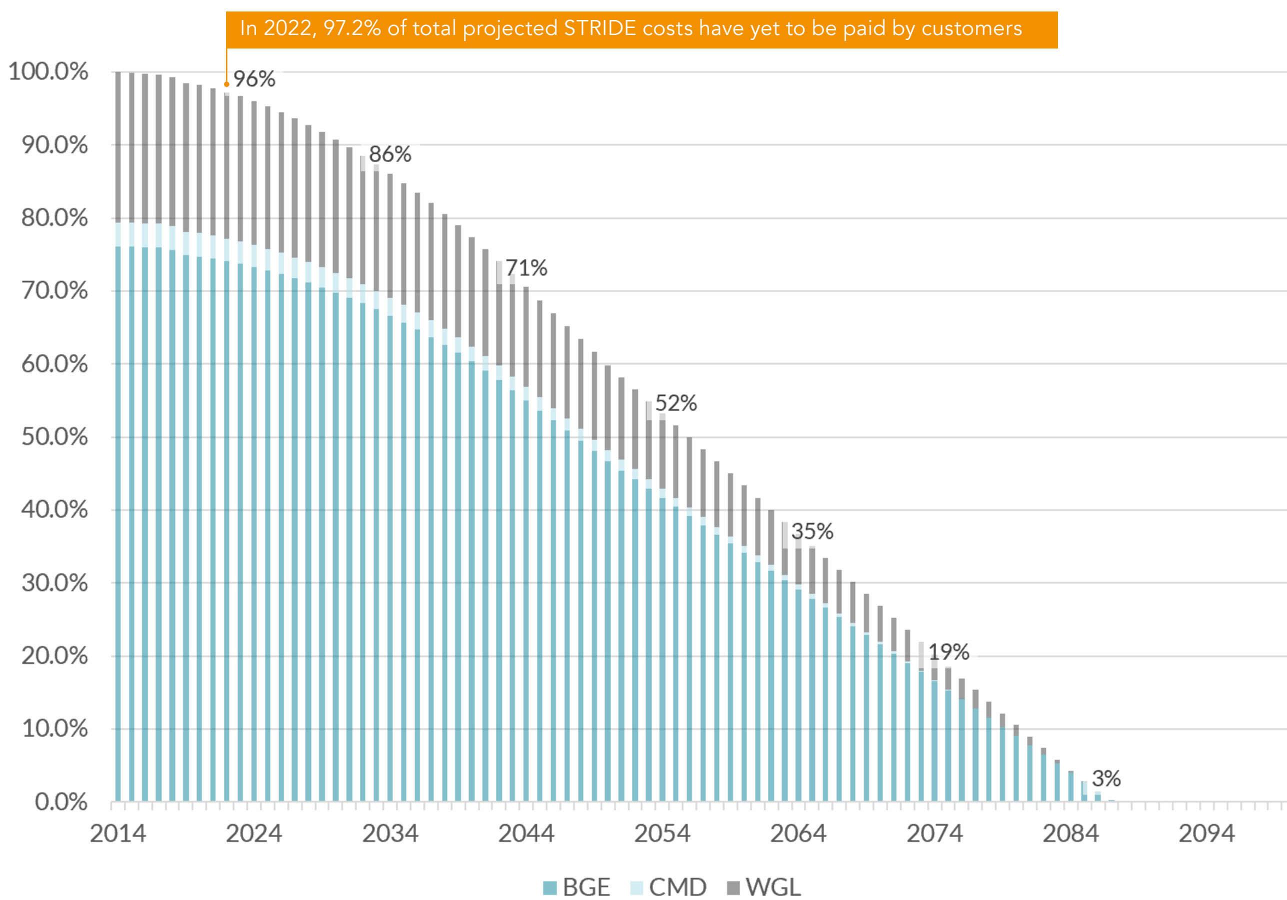
Figure 5.2 shows a snapshot of the progress made periodically by company. Notice that CMD's recovery is faster due to the earlier completion of its STRIDE activities.

We then combined the results of the individual companies into Figure 5.2 to provide a wholistic view of the remaining years that STRIDE costs will be recovered through rates in Maryland. What is important to recognize from this figure is that right now, in 2022, only 2.8% of the planned STRIDE costs have been recovered through rates. STRIDE cost recovery is still at the early stages with Maryland customers expected to be paying off STRIDE costs until 2087.

5.2. Impact of STRIDE on Maintenance Costs

OPC has argued that one of STRIDE's expected benefits should be a reduction in companies' operating costs due to avoided costly leak repairs that no longer need to be addressed. Companies agree that there will be avoided leak repairs but contend this result will not have a corresponding drop in leak repair expenses. BGE has historically made this case in its STRIDE annual audits, where the company notes, "Management does not believe that the STRIDE improvements will result in significant O&M cost savings; however, the infrastructure improvements

Figure 5.2: Percentage of STRIDE Cost Recovery Remaining



are expected to decrease the number of leak repairs that would have otherwise occurred without these improvements."[18] On the other hand, OPC has maintained that if the arguments in favor of STRIDE are that newer, leak-prone pipes will result in lower leaks, then over time there should be a decrease in leak repair expenses.

To assess whether STRIDE has resulted in operating cost reductions, we evaluated the trend in annual maintenance expenditures on main and services since the programs began.

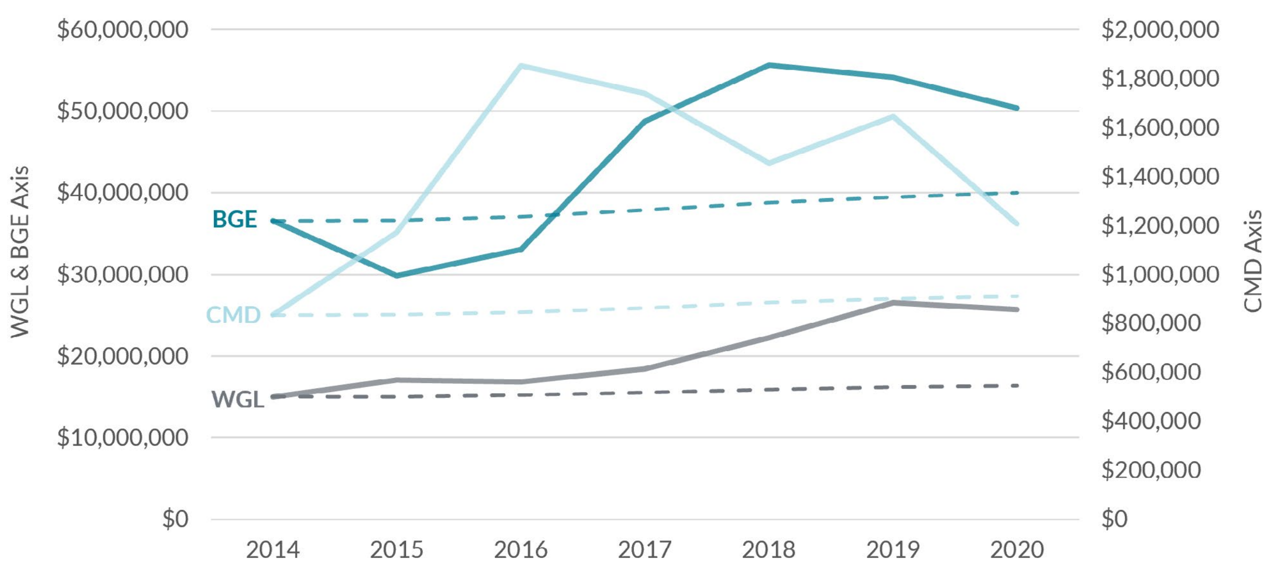
Specifically, we gathered data from each company's annual reports on two FERC operating cost accounts, Account 887 Mains and Account 892 Services. FERC defines those accounts as follows:

- **Account 887 Mains**: This account shall include the cost of labor, materials used, and expenses incurred in the maintenance of distribution mains, the book cost of which is includible in account 376, Mains.
- **Account 892 Services**: This account shall include the cost of labor, materials used, and expenses incurred in the maintenance of services, the book cost of which is includible in account 380, Services.

The annual amounts spent on main and service maintenance by BGE, CMD, and WGL is shown in the figure below. There is no noticeable decrease in operating

All three companies are spending more on operating costs in 2020 than in 2014 when STRIDE began.

Figure 5.3: Historic Main + Service Maintenance Operating Costs



Includes maintance costs in Accounts 887 (Mains) and 892 (Services). Data taken from Annual Reports submitted to MD PSC. WGL costs represent 38.2% of total company costs as an estimate of MD's portion of companywide total.

18 Maillog #214914, Annual STRIDE Plan Agreed-Upon Procedures Report, April 28, 2017, Appendix 3, Management Footnote to Schedule E.

costs for any company since 2014. The dashed line for each company shows what the cost levels would be if the 2014 levels simply increased at the rate of inflation. Because each of these dashed lines in 2020 is below the actual (solid) line, this shows that even after taking inflation into account all three companies are spending more on operating costs in 2020 than in 2014 when STRIDE began.

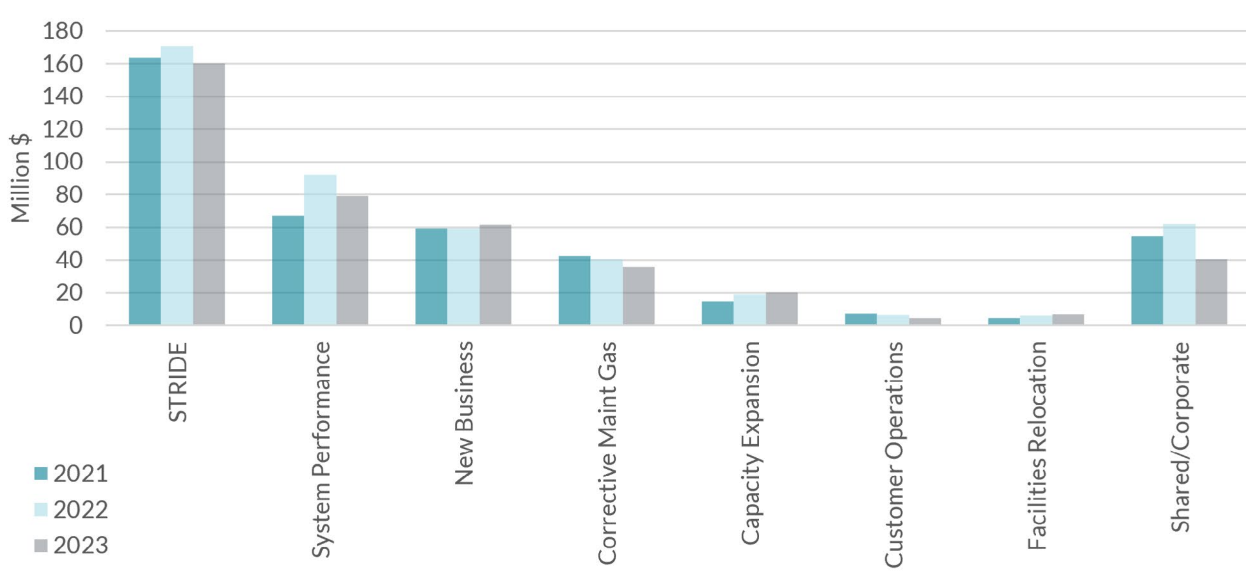
One reasonable interpretation of the results shown above is that the increase in operating costs over inflation from pre-STRIDE levels indicates that customers are not receiving the full benefits intended by STRIDE. The logic is that removing leak-prone or leaking pipes from service results in fewer leak repairs. A more optimistic interpretation of these results is that the operating costs shown here represent a reduction compared to what would have been spent had STRIDE work not been completed. As noted above, this latter interpretation is what the distribution companies contend is correct.

5.3. BGE CAPEX by Category

Within the context of both the gas capital investment discussions and our review of the BGE MYRP capital plans, OPC asked for analysis on the breakdown of BGE's capital plans into different capital categories. We used BGE's three-year gas CAPEX plan submitted as part of the CN 9645 compliance filing to develop Figure 5.4. The figure shows the breakdown of capital investment according to BGE's investment categories. This figure shows that STRIDE (39 percent) continues to be the major focus of BGE's capital investment activities with System Performance (19 percent) and New Business (14 percent) coming in as the second and third highest investment categories. Notably, Shared/Corporate expenses (a combined 12 percent), which includes categories such as real estate and information technology, are higher than some categories, such as corrective maintenance (9 percent) and capacity expansion (4 percent), which directly address safety and reliability problems.

STRIDE continues to be the major focus of BGE's capital investment activities.

Figure 5.4: BGE MYRP CAPEX Plans by Category



This level of information was only available for BGE because it is the only gas utility to submit a multi-year rate plan in Maryland.

5.4. Investments in Distribution System Expansion

This report has focused on gas utility capital expenditures. One aspect of the gas distribution companies' capital spending strategies is their plans for new business and capacity expansion. These categories represent investments being made to grow the gas delivery business beyond its current size. We discuss below trends in investment increases in distribution system expansion. This section summarizes our analysis of capacity expansion and new business for BGE and WGL. Data on new business investments and capacity expansion are not publicly available for CMD.

BGE plans to spend $78.3 million in 2022 on new customer conversions and capacity expansion projects.

5.4.1. BGE

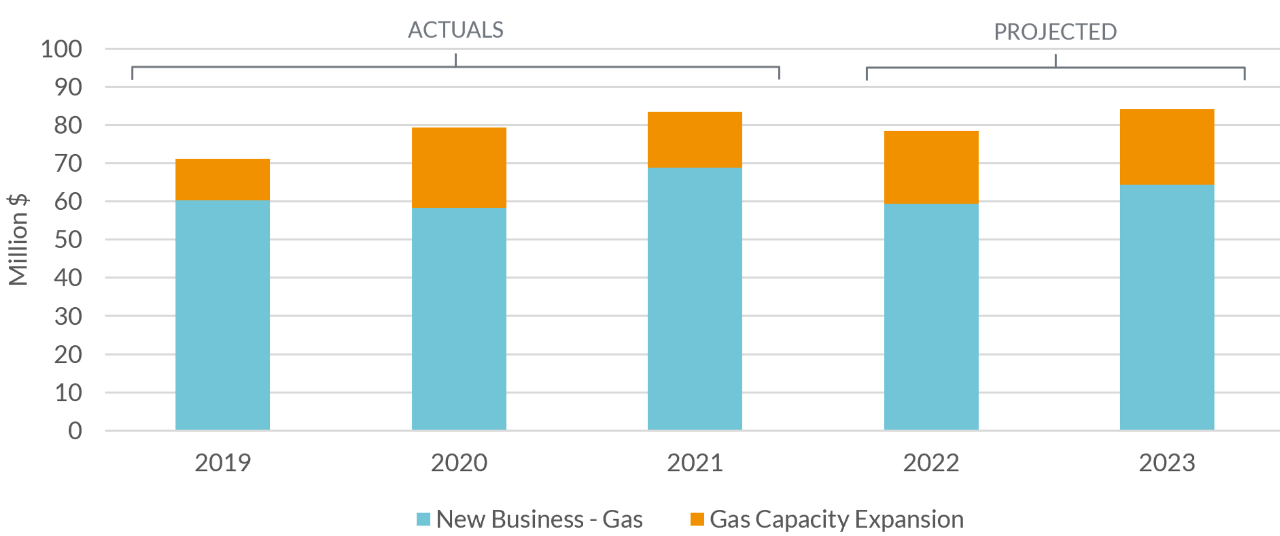
Information on BGE's new business and capacity expansion plans, as well as historical information, was provided as part of the MYRP proceedings in PSC Case No. 9645. BGE plans to spend $78.3 million in 2022 on new customer conversions and capacity expansion projects. This is a slight drop in what has been increasing levels of actual and planned investment in system expansion. As shown in Figure 5.5, the investments pursued through MYRP in 2021 and 2023 on system expansion investment (new business + capacity expansion) represent increases over the historical amounts made in 2019 and 2020.

For context, over the three-year MYRP period, BGE plans to spend 20% ($246 million) of its $1.2 billion capital budget on capacity expansion and new business projects.

5.4.2. WGL

WGL reports its historic expenditures on new business in its annual financial reports. Plans for future new business investments were included in the compliance filing submitted in PSC Case No. 9651.

Figure 5.5: BGE Capital Expenditure on Capacity Expansion and New Business, 2019-2023



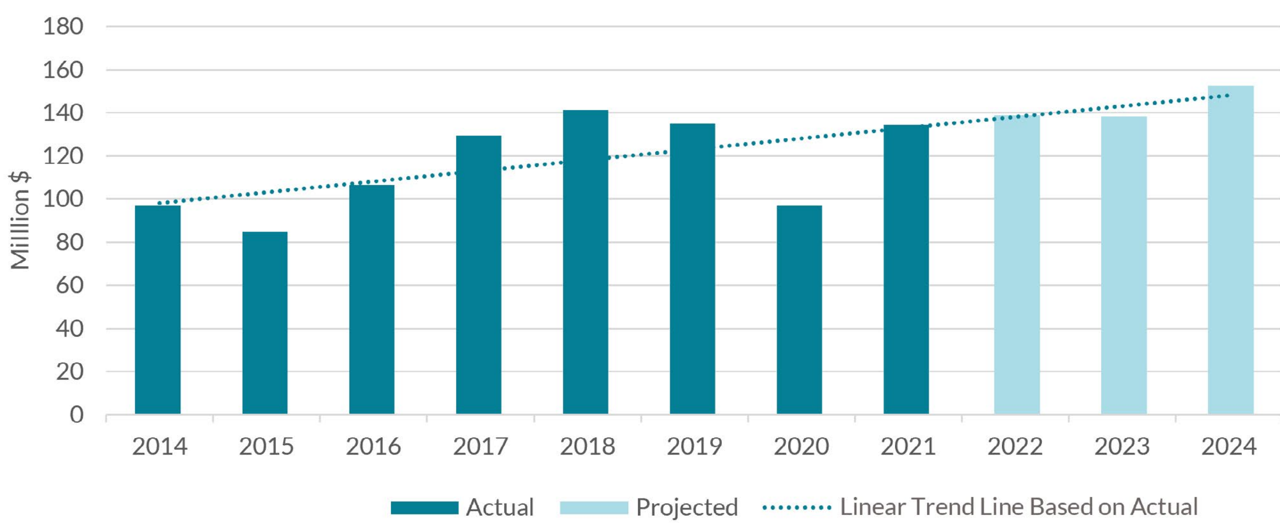
A footnote in these reports notes that the "new business" category also includes "certain projects that support the existing distribution system." We interpret "new business" investments that "support the existing distribution system" to mean expansion of existing system capacity (which BGE's compliance filing calls "capacity expansion").[19] The information on WGL's plans for new business was not available for Maryland alone. Instead, like the information available for total capital investments, the amounts for new business investments are presented in aggregate for all three service jurisdictions. This company-wide information provides insight into WGL's investment efforts being made to expand its gas distribution business.

WGL increased its company-wide capital spending on new business from $97 million in 2014 to $134.4 million in 2021, with a slight dip in expenditures in 2020 ($96.9 million), likely a result due to COVID-19 limitations on entry into customer premises. WGL projections for this category promise an increase in spending in the 2022-2023 period, to $138.3 million for both years, and a further jump in 2024, reaching $152.5 million. Figure 5.6 shows an overall upward trend in spending in the new business category in the decade between 2014 and 2024.

In terms of share of total capital expenditures, spending in this category in 2022 is projected to be 26 percent of all capital expenditures. The share is projected to decrease to 23 percent in the 2023-2024 period.

As stated above, these figures for WGL are company-wide, for service territories in Maryland, Virginia, and the District of Columbia. In rate cases, a cost allocator based on each of WGL's service territory's gas plant-in-service is used to allocate certain shared investment and operating costs. The most recent cost allocator for plant-in-service shows that Maryland's share of gas plant-in-service is 38.2%.[20] Applying this percentage to WGL's 2022-23 projected spending means that WGL's projected Maryland spending on

Figure 5.6: WGL Capital Expenditure on New Business, Actual and Projected (2014-2024)



19 See page 12 of WGL's 2021 Financial report: (*https://www.washingtongas.com/-/media/6b201563983c461c8b-d17a2d50e67af3.pdf*)

20 ML#231646, Case No. 9651, WGL Exhibit ABG-1, Schedule AL, page 2, line 28.

new customers and capacity expansion for 2022 and 2023 is about $52.8 million each year.

5.5. Changes in Bill Composition

Prior to the increase of gas commodity prices in 2020 and 2021, there had been a trend over the previous decade where the distribution portion of bills was increasing, while the commodity portion of the bill decreased or remained relatively constant. We will use BGE as an example to demonstrate this trend. As shown in Figure 5.7, from 2014 to 2020 the overall bill (commodity plus delivery) remained relatively constant from 2014 to 2020 because the decrease in gas commodity prices offset increases in distribution costs.[21]

Over this period a notable flip occurs in 2016: Gas customers begin to pay more to deliver the gas than the gas commodity they use. Figure 5.8 shows the bills from Figure 5.7 broken down into percentage components.

The increase in delivery rates has largely been driven by the capital expenditures, specifically the STRIDE expenditures, addressed in this report. From a customers' perspective, it can be viewed as a positive that improvements in gas extraction have reduced the commodity costs and enabled gas companies to replace leak-prone materials without substantial increases in the total customer bill. The trouble with this perspective is that it ignores the reality that if delivery rates had not increased as rapidly then customers would have paid lower total bills, over this period. Instead of customers saving money from the decrease in commodity costs, gas companies have increased base delivery rates and filled the gap.

Figure 5.7: BGE Typical Winter Bill by Component, 2014-2021 ($/month)

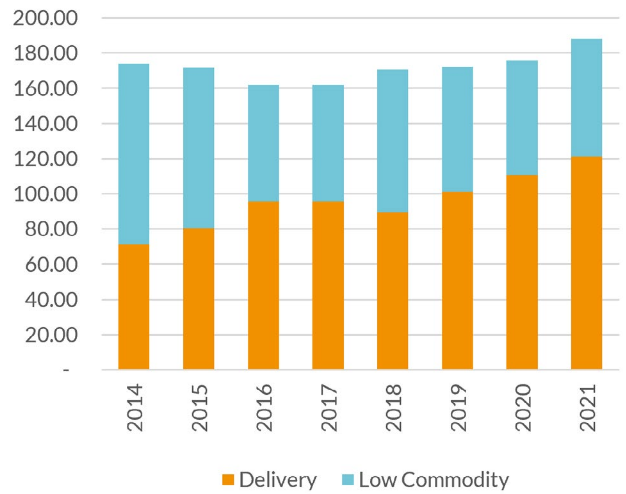
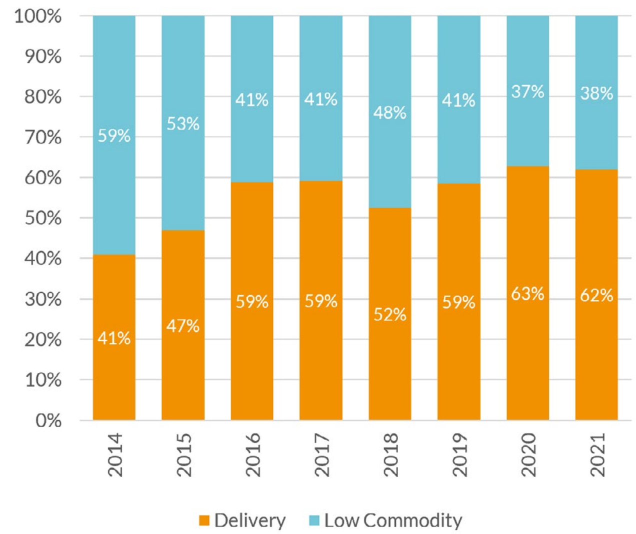


Figure 5.8: BGE Typical Winter Bill by Component, 2014-2021 (%)



If delivery rates had not increased as rapidly, then customers would have paid lower total bills over this period.

21 The delivery portion of the bill impact for 2021 reflects the full offset, i.e., the exclusions, of the rate increase approved by the Commission in Order No. 89678 to address the COVID-19 pandemic; the approved increase in the annual revenue requirement of $54.2 million for 2021 delivery rates will be recovered in future years, with carrying costs.

5.6. Delivery Rates vs. Commodity Prices

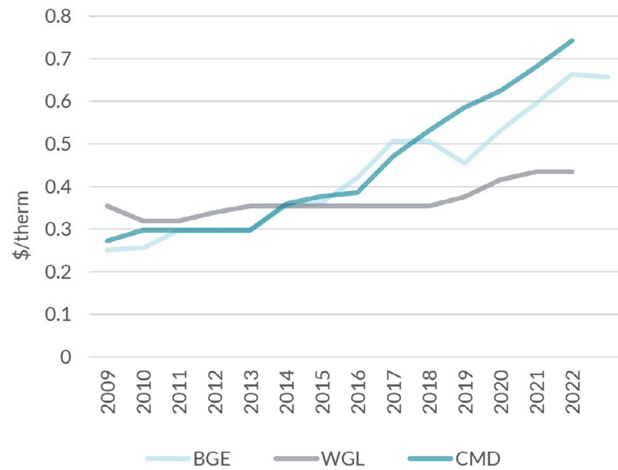
The trend discussed in the previous sections is the result of a period of declining or low-cost gas commodity prices and continued upward pressure from gas utilities on delivery distribution rates. This subsection explores the relationship between the commodity price of gas and the overall costs of gas services.

Delivery charges appear in two separate components of customer rates—a volumetric charge and a demand (or fixed) charge. Steady increases in both the volumetric and fixed portion of delivery rates at the three gas companies from 2009 to 2022 are shown in Figure 5.9 and Figure 5.10.

The steady increase in gas delivery fees has been masked by an unusually prolonged low-price commodity-cost period from 2013 to 2021. Gas prices have historically shown patterns with repeating short (1-2 year) cycles of peaks and troughs in prices. This pattern is evident in the Henry Hub Prices prior to 2013 shown in the figure below where prices routinely dropped but then returned to levels around the previous high mark. This pattern contrasts with the eight-year period between 2013 and 2021 when prices fell and did not return close to the February 2013 levels until February 2021. That gas commodity market now, in 2022, appears to have returned to the era of high price volatility.

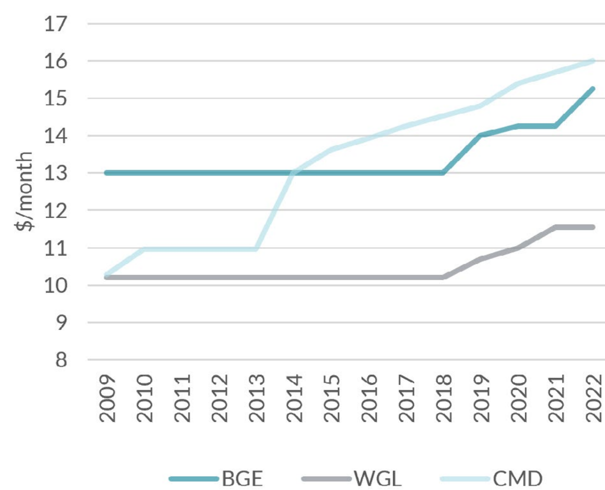
We emphasize this point on gas volatility and the rising cost of gas delivery because price is one of the main factors used by gas companies to promote the continued transition of customers to natural gas away from fuel oil. Versions of the moniker "clean and affordable natural gas" are a common phrase used on gas company websites[22] and regulatory filings.

Figure 5.9: Volumetric Delivery ($/therm) rates, 2009-2022



WGL has a three-block decreasing volumetric rate structure where customers are charged decreasingly lower rates for the first 45 therms, next 135 therms (45-180 therms), and all other usage above 180 therms. The volumetric rate in the figure is a weighted average rate calculated using an assumed 130 therm per month.

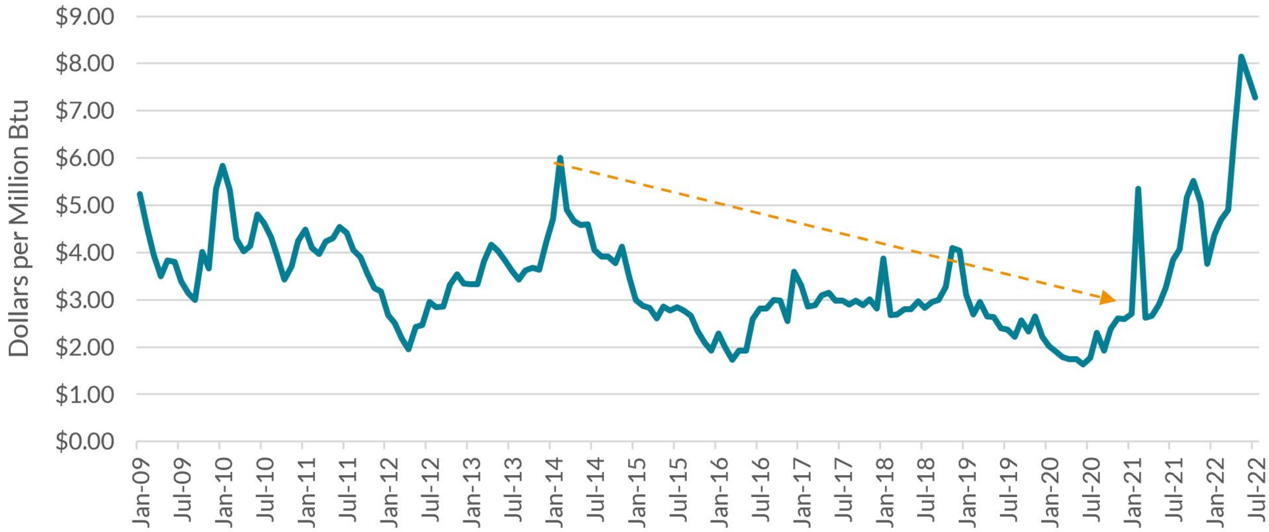
Figure 5.10: Fixed Charges ($/month), 2009-2022



> The steady increase in gas delivery fees has been masked by an unusually prolonged low-price commodity-cost period from 2013 to 2021

22 See the websites of BGE (*https://www.bge.com/SafetyCommunity/Education/Pages/BGENaturalGas.aspx*) and WGL (*https://www.washingtongas.com/safety-education/education/about-natural-gas*).

Figure 5.11: Henry Hub Gas Spot Price, January 2009-May 2022



Source: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

For example, BGE justified the budget for new business conversions in its MYRP by identifying the "problem statement" intended to be addressed by new business projects—customers wanting to switch from existing electric, propane, or oil to "more cost efficient, natural gas."[23] It is true that drops in commodity prices over the last decade have, at times, made gas a more affordable energy option for some customers. But utility marketing language overlooks the fact that the low commodity prices over this period masked the reality that gas is prone to extremes in price volatility, just like fuel oil.

Gas is prone to extremes in price volatility.

The volatility in prices residential customers paid for gas was around **three times greater** than the volatility in electricity prices over this period.

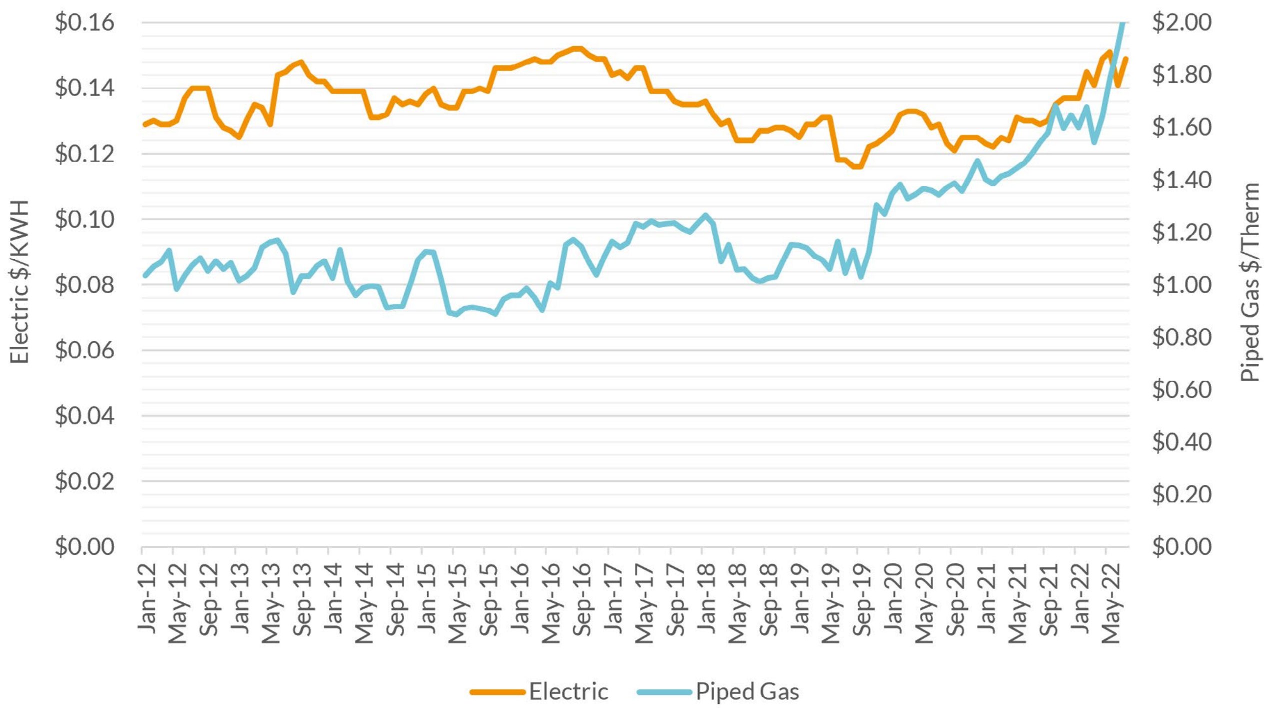
The volatility of gas prices contrasts with electricity, as shown in Figure 5.12. This figure uses data on electricity and gas end-user prices tracked by the Bureau of Labor and Statistics (BLS). Evident in this figure is that between 2009 and 2022, there is greater variability in the price paid by customers for gas than electricity. Statistically, the volatility in prices residential customers paid for gas was around three times greater than the volatility in electricity prices over this period.[24]

Setting aside the issue of volatility, the recent increases in gas prices also show that the proposition that gas is "the more affordable" energy source might be more marketing than reality. To better compare the changes in electricity and gas prices, we indexed the prices using a baseline. In Figure 5.13 below, the January 2012 prices for gas and electricity are used as baselines (January 2012 = 1) and then

23 Case No. 9645, ML# 233739 at page 46.

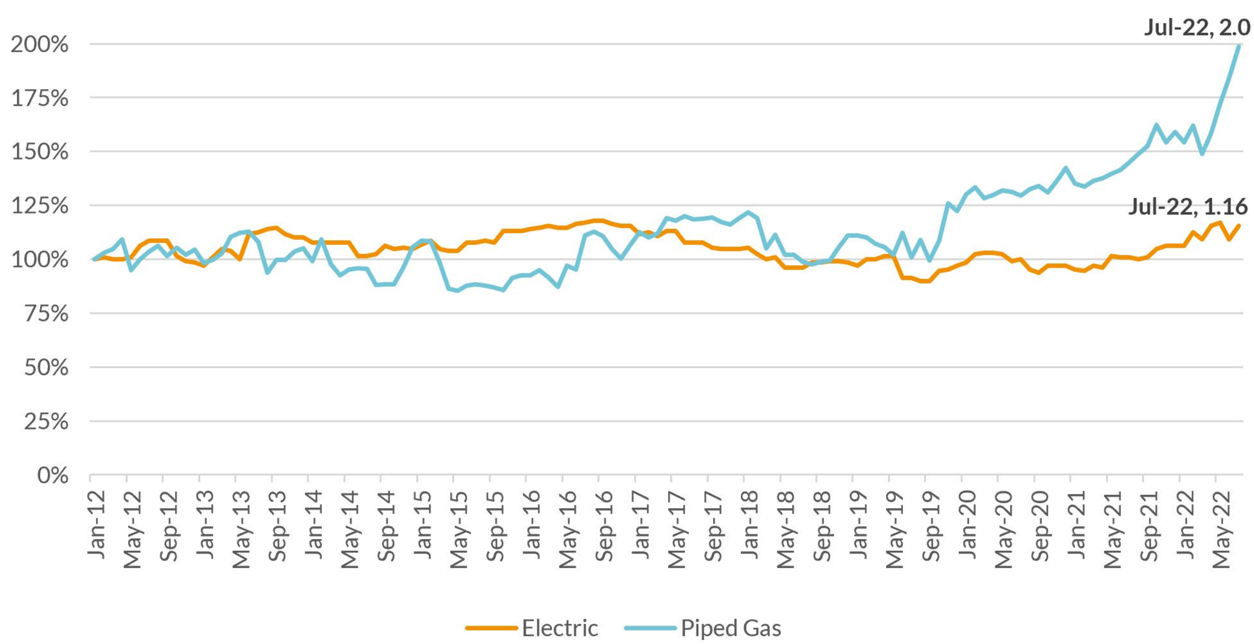
24 Volatility was estimated by calculating the coefficient of variation (CV = standard deviation / mean) of gas and electricity prices over the evaluation period. The CV of gas prices was 0.18 and the CV of electricity prices was 0.06.

Figure 5.12: BGE Residential Electricity and Gas Prices, January 2012-May 2022



Price data on Baltimore electricity and gas prices from Bureau of Labor Statistics (BLS)

Figure 5.13 Indexed BGE Electricity and Gas Prices, January 2012-May 2022 (index = January 2012)



Price data on Baltimore electricity and gas prices from Bureau of Labor Statistics (BLS) every subsequent monthly indicator represents the relationship between that month's price and the baseline price (Monthly price / January 2012 price). What comes across in this figure is that electricity prices have stayed relatively around the same levels since 2012. Prices are 16 percent higher in May 2022 from ten years earlier. On the other hand, gas prices have increased rapidly in the last three years and are now double prices in January 2012. This result exemplifies the combined effect of the end of low-cost gas and the rise in delivery charges over this same period.

Gas companies may argue that it is unfair to use the current high prices as a comparison given the market conditions due to the combined effects of pandemic-driven supply constraints and the war in Ukraine. Regardless of recent gas commodity price spikes, the figure above shows the general trend starting in 2019 of natural gas prices increasing faster than electricity end-user prices.

GLOSSARY AND ACRONYMS

Term	Definition	Source
Commodity rate	The unit rate charged for each unit of gas actually purchased under a contract.	New York State Public Service Commission. "Glossary of Terms Used by Utilities and Their Regulators". Available at: https://www.dps.ny.gov/glossary.html.
Depreciation	The loss in service value not restored by current maintenance and incurred in connection with the consumption or prospective retirement of property in the course of service from causes against which the carrier is not protected by insurance, and the effect of which can be forecast with a reasonable approach to accuracy	"18 CFR Ch. I, Pt. 352." *Code of Federal Regulations*. Available from: https://www.ferc.gov/sites/default/files/2020-06/18cfr352.pdf. Accessed 6 July 2022.
Rate Base	The net investment of a utility in property that is used to serve the public; this includes the original cost net of depreciation, adjusted by working capital, deferred taxes, and various regulatory assets—the term is often misused to describe the utility revenue requirement	Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/.
Return on Equity	The rate of earnings realized by a utility on its shareholders' assets, calculated by dividing the earnings available for dividends by the equity portion of the rate base.	New York State Public Service Commission. "Glossary of Terms Used by Utilities and Their Regulators". Available at: https://www.dps.ny.gov/glossary.html.
Revenue Requirement	The annual revenues that the utility is entitled to collect (as modified by adjustment clauses). It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base. In most contexts, revenue requirement and cost of service are synonymous.	Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/.
Stranded Assets	Assets that have suffered from unanticipated or premature write-downs, devaluation or conversion to liabilities.	Lloyd's. 2017."Stranded Assets." Available at: https://www.lloyds.com/strandedassets.

Acronyms

BGE	Baltimore Gas & Electric
CAPEX	capital expenditures
CAGR	compound annual growth rate
CMD	Columbia Gas of Maryland
CN	Case Number
OPC	Office of People's Counsel
MACRS	Modified Accelerated Cost Recovery System
MYRP	Multi-year rate plan
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSC	Public Service Commission
STRIDE	Strategic Infrastructure Development and Enhancement (Public Utilities Article, Ann. Code of Md., § 4-210)
VMC	vintage mechanically coupled
WACC	weighted average cost of capital
WGL	Washington Gas Light

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