BEFORE THE
MARYLAND PUBLIC SERVICE COMMISSION

PETITION OF THE OFFICE OF PEOPLE'S COUNSEL FOR NEAR-TERM, PRIORITY ACTIONS AND COMPREHENSIVE, LONG-TERM PLANNING FOR MARYLAND'S GAS COMPANIES	* * * *	Case No. 9707 Phase II

* * * * * * * * * * * * *

INITIAL AND REPLY TESTIMONY

OF

KENJI TAKAHASHI

ON BEHALF OF THE OFFICE OF PEOPLE'S COUNSEL

May 4, 2026

TABLE OF CONTENTS

INTRODUCTION 1

I. Summary and Recommendations 6

II. Gas Demand and Load Forecasting 12

A. Overview of Gas Demand Forecasting Methodologies 12

B. Reliance on Historical Trends in Gas Demand Forecasting 20

C. Emerging Market Trends and Policy Drivers of Gas Demand 26

III. Improving Gas Demand Forecasting Through Better Market, Policy and Design Day Assumptions 34

A. The Commission Should Direct Gas Companies to Better Account for Emerging Market Trends in Demand Forecasting. 35

B. The Commission Should Direct Gas Companies to Conduct Scenario-Based Demand Forecasting to Account for Current and Emerging Policy Impacts 38

C. The Commission Should Direct Gas Companies to Account for Realistic Space Heating Constraints in Design Day Forecasting 47

IV. Recommendations for Future Planning Practices 56

EXHIBIT KT-1 – Resume of Kenji Takahashi

EXHIBIT KT-2 – Data Requests and Responses Referenced in Testimony

EXHIBIT KT-3 – Maryland Building Decarbonization Study Prepared for the Maryland Commission on Climate Change by Energy and Environmental Economics, Inc. (2021)

EXHIBIT KT-4 – An Assessment of Electrification Impacts on the Maryland Electric Grid Prepared for the Maryland Public Service Commission by The Brattle Group (2023)

INITIAL AND REPLY TESTIMONY OF KENJI TAKAHASHI

INTRODUCTION

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

A. My name is Kenji Takahashi. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources, energy efficiency policies and programs, integrated resource planning, electricity market modeling and assessment, renewable resource technologies and policies, and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse's staff includes over 35 professionals with extensive experience in the electricity and gas industries.

Q. Please describe your educational background and qualifications.

A. I hold a Master's degree in Urban Affairs and Public Policy with a concentration in Energy and Environmental Policy from the Biden School of Public Policy and Administration at the University of Delaware. I also completed the Massachusetts Institute of Technology's professional program "Sustainable Infrastructure Systems: Planning and Operations." My resume is attached as Exhibit KT-1.

Q. Please summarize your work experience.

A. Since joining Synapse in 2004, I have specialized in decarbonization planning, programs, and technologies across the energy sector, with particular expertise in evaluating the energy, economic, and environmental impacts of building decarbonization measures such as energy efficiency, electrification, demand response, and other distributed energy resources.

Over the past 20 years, I have assessed the design, impacts, and potential of energy efficiency, demand response, and distributed energy resources policies and programs in over 40 jurisdictions across North America for a variety of clients. These include environmental groups, municipal, state, and provincial governments, and federal agencies such as the U.S. Environmental Protection Agency and the U.S. Department of Energy.

I also have extensive experience assessing the impacts of building decarbonization on gas and electric load forecasts, with a particular focus on electrification, utility forecasting methodologies, and non-pipeline alternatives.

My work has frequently involved evaluating long-term load forecasting assumptions, scenario analysis, and infrastructure planning under decarbonization and electrification pathways. For example, I recently led analyses of building decarbonization scenarios in Oregon and Minnesota, evaluating the potential impacts on emissions, system peak loads, and energy system investments.[1] I have also led multiple analyses of Nova Scotia Power's load forecasting on behalf of the Nova Scotia Utility and Review Board, with a particular focus on building decarbonization and load forecast assumptions.[2] Further, on behalf of the Maryland Office of People's Counsel, I led Synapse's technical support for Maryland's Electrification Study Group, critically evaluating and advising on key assumptions and methodologies related to building and transportation electrification and independently analyzing impacts on winter peak loads and distribution system investments to inform the Public Service Commission's assessment of managed electrification under the Climate Solutions Now Act.

In addition, I have provided expert testimony on building electrification program design, gas utility planning, and gas and electric utility load forecasting in proceedings involving Potomac Electric Power Company ("Pepco") and Baltimore

[1] DeLeon, S., K. Takahashi, E. Carlson, A. S. Hopkins, S. Kwok, J. Litynski, C. Mattioda, L. Metz. 2024. *Minnesota Building Decarbonization Analysis: Equitable and Cost-Effective Pathways Toward Net-Zero Emissions for Homes and Businesses*. Available at: https://www.synapse-energy.com/net-zero-emissions-oregon-buildings; Takahashi, K., S. Kwok, J. Tabernero, F. Frost. 2022. *Toward Net Zero Emissions from Oregon Building*. Available at: https://www.synapse-energy.com/net-zero-emissions-oregon-buildings.
[2] Takahashi, K., A. Glaser Schoff, B. Havumaki. 2024. *Evidence Regarding Nova Scotia Power's 2024 Load Forecast*. Available at: https://www.synapse-energy.com/nova-scotia-powers-annual-load-forecast-evaluation.

Gas and Electric Company ("BGE") in Maryland (on behalf of the Maryland Office of People's Counsel), New Mexico Gas Company (on behalf of the New Mexico Attorney General's Office), and Public Service Company of Colorado (on behalf of the Town of Breckenridge).

Finally, I have co-authored several studies addressing the future of gas utility planning and non-pipeline alternatives ("NPA"). Notable examples include *A Framework for Long-Term Gas Utility Planning in Colorado*,[3] prepared for the Colorado Energy Office, and *Gas Regulation for a Decarbonized New York*,[4] prepared for the Natural Resources Defense Council.

Q. Have you previously testified in proceedings before state utility commissions in other jurisdictions?

A. Yes. I have testified and participated in regulatory proceedings before the Massachusetts Department of Public Utilities, New York Public Service Commission, Pennsylvania Public Utility Commission, New Jersey Board of Public Utilities, Colorado Public Utilities Commission, Ontario Energy Board, and Nova Scotia Utility and Review Board.

Q. On whose behalf are you appearing?

A. I am presenting testimony on behalf of the Maryland Office of People's Counsel.

[3] Hopkins, Asa S., Alice Napoleon, and Kenji Takahashi. 2021. *A Framework for Long-Term Gas Utility Planning in Colorado*. Available at: https://www.synapse-energy.com/sites/default/files/Long-Term_Gas_Planning_in_Colorado_21-086.pdf.

[4] Hopkins, Asa, Alice Napoleon, and Kenji Takahashi. 2020. *Gas Regulation for a Decarbonized New York: Recommendations for Updating New York Gas Utility Regulation*. Available at: https://www.synapse-energy.com/sites/default/files/Gas_Regulation_Decarbonized_NY_19-082.pdf.

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

A. The purpose of my testimony is to address demand and load forecasting in the context of gas planning practices, market trends, and the State's climate goals as it relates to *issue numbers 1, 3 and 12 in the Commission Order No. 91791:*

(1) each natural gas company, and combination gas and electric company, subject to the Commission's jurisdiction shall provide a full description of its current natural gas capacity, supply, and capital investment planning practices. This description shall include, but is not limited to, a discussion of how current gas company planning practices address State climate goals;

(3) What policies, guidelines, or regulations, if any, should be adopted to ensure that future natural gas company planning practices adequately address the State's climate goals?

(12) How should future technological innovations, demand response programs, more efficient appliances, and other mechanism, be addressed in gas company planning?

My testimony also addresses utility arguments on demand and load forecasting as laid out in their February 9, 2026 filings.

Q. Have you prepared exhibits to accompany your testimony?

A. Yes. I have prepared the following exhibits:

- Exhibit KT-1: Resume
- Exhibit KT-2: Data Requests and Responses Referenced in Testimony
- Exhibit KT-3: Maryland Building Decarbonization Study Prepared for the Maryland Commission on Climate Change by Energy and Environmental Economics, Inc. (2021)

- Exhibit KT-4: An Assessment of Electrification Impacts on the Maryland Electric Grid Prepared for the Maryland Public Service Commission by The Brattle Group (2023)

I. Summary and Recommendations

Q. Which gas company planning practices did you review for purposes of this testimony?

A. My review—and the summary conclusions and recommendations presented in this testimony—focus primarily on the planning, forecasting, and related testimony of Baltimore Gas and Electric Company ("BGE"), Washington Gas Light Company ("WGL"), and Columbia Gas of Maryland ("Columbia"). For clarity, references to "the gas companies," "the utilities," or similar terms in this testimony refer to BGE, WGL, and Columbia unless otherwise noted.

Q. Please summarize your primary conclusions concerning gas demand forecasting by BGE, WGL, and Columbia.

A. My primary conclusions are organized into three areas of concern: (1) emerging market trends, (2) policy-related forecasting practices, and (3) design day (peak day) demand forecasting.[5]

(1) Impacts of Emerging Market Trends on Demand Forecasting

a) BGE, WGL, and Columbia's current forecasting practices generally use approaches that are likely to underrepresent the impacts of observable,

[5] "Design day demand" represents estimated peak gas demand under specified extreme weather and related planning assumptions intended to reflect rare high-demand conditions for system planning purposes.

emerging market trends—particularly increasing electrification, changing heating equipment preferences, and shifts in customer fuel choice—because these developments are recent and therefore have limited influence within the long-term historical datasets. As a result, the gas utilities' reliance primarily on historical trends may materially overestimate future gas demand.

b) Historical gas consumption within BGE, WGL, and Columbia's jurisdictions has remained relatively stable in aggregate over the last two decades, both for the combined residential and commercial sectors and across total consumption, including residential, commercial, and industrial customers. At the utility level, this overall stability reflects modest variation, with BGE and Columbia exhibiting modest declining trends in residential and commercial consumption, while WGL shows modest growth. However, when all customer sectors are considered, BGE exhibits a more pronounced long-term decline in total gas consumption relative to the other utilities. Within this pattern, combined residential consumption has remained relatively stable with a modest declining trend, while combined commercial consumption has increased modestly, with these sector-specific trends largely offsetting one another at the aggregate level. On a per-customer basis, residential gas consumption has steadily declined over this period. This decline in residential usage per customer—given the large share of residential customers and system throughput—places upward pressure on gas rates, all else being equal, as utilities must recover fixed infrastructure and system costs over lower average consumption levels. This pressure would be further amplified if capital investments continue to increase while average customer usage declines.

c) Absent explicit adjustment for emerging and future developments, the utilities' current historically focused, regression-based forecasting methodologies are likely to project a continuation of historical patterns of relatively flat aggregate consumption rather than the more substantial shifts in demand suggested by

observed market trends and policy developments. While historical methods form the basis of conventional planning frameworks, they are inherently backward-looking and are not well suited to capturing structural changes that are emerging but not yet fully reflected in historical data.

d) Future annual gas demand and design day demand are highly likely to decline over time relative to the utilities' forecasts, given relatively flat historical gas demand among the utilities, slowing residential gas-heating growth, expanding EmPOWER fuel-switching incentives, and existing and forthcoming climate policies that are expected to further accelerate electrification and reduce reliance on gas.

(2) Impacts of Policy on Demand Forecasting

a) BGE, WGL, and Columbia's demand forecasts do not prospectively incorporate the impacts of recently enacted, proposed, or forthcoming state and local policies—such as Building Energy Performance Standards, EmPOWER electrification incentives, a Clean Heat Standard, a Zero-Emission Heating Equipment Standard, and local building electrification requirements.[6] Instead, these impacts are generally reflected in the utilities' forecasts only after they become observable in historical demand data, creating a lag that is likely to underestimate future declines in gas demand associated with the State's climate policies.

b) Because gas infrastructure planning involves long-lived capital investments, BGE, WGL, and Columbia's delayed recognition of structural demand decline increases the risk that infrastructure and supply planning decisions will become increasingly misaligned with future demand.

[6] I will discuss these policies later under Section II-C.

c) BGE, WGL, and Columbia's failure to adequately account for structural changes such as slowing gas-heating growth, accelerating electrification, expanding fuel-switching incentives, and evolving climate policies increases the risk of overinvestment in gas system infrastructure and supply resources. In turn, such overinvestment risks unnecessary capital expenditures, stranded assets, higher customer rates, and increased customer bills.

(3) Design Day Demand Forecasting

a) BGE, WGL, and Columbia currently develop design day forecasts by extrapolating historical demand relationships to rare and extreme cold conditions that may exceed practical levels of heating demand with current heating, ventilation, and air conditioning ("HVAC") equipment. The forecasts therefore assume HVAC equipment will handle continued proportional growth, but whether that assumption is correct depends on industry sizing practices, real-world heating system capacity constraints, and observed customer behavior. By relying on assumptions without sufficient empirical validation against realistic heating system constraints and observed demand behavior, the gas companies may materially overstate peak gas demand and contribute to unnecessary infrastructure or gas supply investments.

b) Beyond baseline design day methodology, certain Maryland gas companies, particularly BGE and WGL, incorporate additional layers of conservatism—including upper-tail statistical confidence assumptions, reserve margins, and other peak-demand adjustments—that may overestimate peak demand levels if not empirically validated against realistic heating system constraints and observed demand behavior.

Q. Please summarize your recommendations.

A. My recommendations on the gas companies' load forecasting methodologies include the following:

(1) Impacts of Emerging Market Trends on Demand Forecasting

The Commission should require the gas companies to:

a) Supplement traditional regression-based forecasting methods—which rely on historical data to quantify how gas usage varies with key drivers such as weather, economic activity, and customer growth—with forward-looking market analyses that explicitly incorporate recent and observable trends in electrification, heat pump adoption, fuel-switching behavior, and customer technology preferences.
b) Use available market data—including heating equipment installation trends, replacement choices, and fuel selection patterns—to better estimate structural shifts in customer counts, usage per customer, and long-term gas demand trajectories.

(2) Impacts of Policy on Demand Forecasting

The Commission should require the gas companies to:

a) Adopt scenario-based demand forecasting practices that explicitly model the potential impacts of current, proposed, and forthcoming State and local policies across a range of plausible policy implementation and market response pathways.
b) Develop business-as-usual, policy-aligned, and accelerated transition scenarios and evaluate impacts on gas customer counts, usage per customer, design day demand, capital investment needs, and non-pipeline alternative opportunities under each pathway.

c) Integrate these scenario results directly into infrastructure planning, capital investment decisions, and long-term gas system planning to evaluate how different demand trajectories affect infrastructure needs, overinvestment risk, stranded asset exposure, and customer rates and bills.

(3) Design Day Demand Forecasting

The Commission should require the gas companies to:

a) Re-evaluate design day assumptions to determine whether current methodologies materially exceed realistic heating requirements when compared with HVAC sizing practices, practical heating system capacity constraints, and observed demand behavior during extreme cold events.
b) Conduct empirical analyses of actual gas demand during extreme weather events to determine whether aggregate gas demand growth materially diminishes as heating systems approach practical operating limits, rather than assuming continued proportional growth under increasingly extreme conditions.
c) Participate in and support a Commission-directed process with opportunity for public input to develop a more transparent and consistent framework for design day planning assumptions, including clear justification for design temperatures, return periods, reserve margins, confidence intervals, and similar planning assumptions—both individually and in combination—to ensure that their cumulative effect does not produce unreasonable or unsupported levels of conservatism.

Collectively, these reforms would improve gas utilities' forecasting accuracy, better align gas planning with Maryland's climate goals and customer affordability

interests, reduce the risk of unnecessary infrastructure investment and stranded assets, and support prudent long-term decision-making.

II. Gas Demand and Load Forecasting

Q. Please provide an overview of this section of your testimony.

A. In this section, I provide an overview of the gas utilities' demand forecasting methodologies and discuss the major drivers of gas demand, including how those drivers are changing over time. *This section addresses issues 1, 3, and 12 identified in Order No. 91791.*[7]

A. Overview of Gas Demand Forecasting Methodologies

Q. Please describe the importance of demand forecasting in utility planning and operations and in addressing the State's climate goals and market trends.

A. Demand forecasting, which includes both annual consumption and peak day (design day) demand, is central to natural gas utility planning and plays a critical role in determining system size, infrastructure investment, gas supply plans and contracts, utility revenues and rates, and greenhouse gas ("GHG") emissions.

[7] These issues are as follows:
(1) each natural gas company, and combination gas and electric company, subject to the Commission's jurisdiction shall provide a full description of its current natural gas capacity, supply, and capital investment planning practices. This description shall include, but is not limited to, a discussion of how current gas company planning practices address State climate goals;
(3) What policies, guidelines, or regulations, if any, should be adopted to ensure that future natural gas company planning practices adequately address the State's climate goals?
(12) How should future technological innovations, demand response programs, more efficient appliances, and other mechanism, be addressed in gas company planning?

First, gas companies use forecasts to determine the size and timing of system investments, including pipeline capacity, storage, and other infrastructure. Demand forecasts can also incorporate the impacts of non-pipeline alternatives ("NPAs"), such as energy efficiency, demand response, electrification, and other strategies that can reduce or defer traditional gas infrastructure or gas supply needs. Overestimation of future demand can lead to unnecessary capital investments, while underestimation can raise reliability concerns. Forecasts are also used to determine the required level of gas supply and capacity procurement.

Second, forecasts of annual gas consumption (demand) directly affect utility revenues and rates. Emerging market trends toward clean and highly efficient heating technologies, such as heat pumps, as well as State climate policies, suggest that gas consumption will substantially decline over the long term.[8] As consumption declines, all else being equal, fixed costs are recovered over a smaller sales base, leading to increased customer rates.

[8] Energy and Environmental Economics, Inc. (E3). 2021. *Maryland Building Decarbonization Study.* Prepared for the Maryland Commission on Climate Change. 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 (attached as Exhibit KT-3); Maryland Commission on Climate Change. 2021. *Building Energy Transition Plan: A Roadmap for Decarbonizing the Residential and Commercial Building Sectors in Maryland*. Available at: https://mde.maryland.gov/programs/air/ClimateChange/MCCC/Commission/Building%20Energy%20Transition%20Plan%20-%20MCCC%20approved.pdf; Maryland Climate Subcabinet. 2025. *2025 Annual Report of the Maryland Climate Subcabinet.* Available at: https://news.maryland.gov/mde/2025/12/10/second-annual-climate-subcabinet-report-highlights-gains-in-cleaner-vehicles-energy-efficient-buildings-and-lower-greenhouse-gas-emissions/; VEIC. 2026. *Evaluation of 2025 Q3–Q4 EmPOWER Maryland Semi-Annual Program Reports*. Prepared for the Maryland Office of People's Counsel, Case No. 9705. at 46. Available at:

Third, effective utility planning requires evaluating and incorporating State climate policies. While forecasts do not directly determine emissions outcomes, they shape decisions regarding infrastructure investment and gas supply procurement, which in turn affect long-term emissions trajectories. In addition, forecasts serve as a critical analytical tool to assess whether current and proposed policies are sufficient to meet the State's greenhouse gas reduction targets. By comparing forecasted demand under different policy scenarios, utilities and regulators can evaluate the extent to which existing measures align with Maryland's climate goals and identify potential gaps and risks that may require additional policy or planning actions.

Q. How do gas companies across the country currently develop gas demand forecasts?

A. Gas utilities across the country distinguish between annual demand (or sales) forecasts, which reflect total gas consumption over a year, and design day demand forecasts, which estimate peak system requirements under extreme cold weather conditions.

Gas companies across the country generally develop forecasts of annual gas demand and peak day demand using approaches grounded in historical data and statistical modeling. In particular, gas companies rely on regression-based (econometric) methods, which use historical data to quantify how gas usage varies

https://opc.maryland.gov/Portals/0/Files/Publications/20260415%20-%20OPC%20Comments%20on%20Q3-Q4%20Semi-Annual%20Reports%20-%20CN%209705.pdf.

with key drivers such as weather, economic activity, and customer growth. These models estimate statistical relationships between demand and these variables by fitting equations to past data, allowing analysts to isolate the effect of each driver while holding others constant. The estimated relationships are then applied to assumptions about future conditions—such as normal weather, expected economic growth, and projected customer counts—to generate forecasts of future gas demand. While many gas companies develop both types of forecasts (annual and design day) using regression-based methods, the extent to which each is developed and used for planning purposes varies across companies.

Q. How do Maryland's gas companies develop annual gas demand forecasts?

A. To estimate annual gas demand forecasts, BGE, WGL, and Columbia use a common regression-based framework, though their specific modeling approaches and assumptions differ.

a) BGE does not develop a formal annual gas demand forecast. Instead, its planning framework centers on design day demand forecasts and short-term operational projections based on historical demand patterns and near-term weather forecasts.[9]

b) WGL uses regression models that relate gas demand to weather variables (e.g., heating degree days), customer growth, and other drivers to develop an annual gas demand forecast. WGL estimates usage per customer based

[9] BGE response to OPC Data Request ("DR") 1-6.

on actual usage and actual heating degree days ("HDD")[10] and develops normal weather forecasts by substituting normal HDD values.[11, 12]

c) Columbia uses regression models to forecast annual gas demand by estimating customer counts and usage per customer and combining these components to derive total consumption.[13] The models relate gas usage to weather variables (e.g., heating degree days), economic factors, and customer characteristics, with weather normalization[14] based on applying normal heating degree days derived from a 20-year historical period.[15]

Overall, while companies that develop annual demand forecasts generally use broadly similar variables, they differ significantly in whether and how they develop and use those forecasts for planning purposes. Across these companies, future gas demand is projected by applying historical relationships to assumptions about future conditions, with adjustments reflecting expected changes in key drivers. As a result, annual demand forecasts typically show gradual changes over

[10] Heating degree days ("HDD") are a weather-based measure used to estimate how much heating is needed to maintain indoor comfort when outdoor temperatures fall below a specified base temperature, typically 65°F in the United States. For each day, HDD is calculated as the difference between the base temperature and the day's average outdoor temperature when that average is below the base; if the average temperature is above the base, HDD is zero.
[11] WGL response to OPC DR 1-10.
[12] Normal HDD represent the long-term average number of heating degree days for a given location and time period, typically based on historical weather data over a standardized climatological period such as 30 years (e.g., NOAA climate normals).
[13] Columbia response to OPC DR 1-17.
[14] Weather normalization adjusts energy use data to show what demand would be under typical weather conditions, rather than unusually hot or cold weather, so long-term usage trends can be analyzed more accurately without distortion from unusually warm or cold periods.
[15] Columbia responses to OPC DR 1-17 and 1-020.

time, such as modest declines in usage per customer due to energy efficiency improvements and warming trends.

Q. How do Maryland's gas companies develop design day demand forecasts?

A. BGE, WGL, and Columbia estimate peak day demand using a design day methodology, which applies relationships between peak daily gas demand and key weather variables to extreme cold conditions intended to represent rare events. These design day conditions are typically derived from historical weather data or statistical analysis of extreme weather events and are often expressed in terms of a specified frequency of occurrence, or "return period" (e.g., a 1-in-20-year event). In some cases, design day conditions include both temperature and other weather variables, such as wind speed. WGL and BGE apply additional assumptions, such as reserve margins or higher statistical confidence levels,[16] to estimate design day demand to ensure reliability under extreme conditions.

While the general framework is similar across gas companies, the specific assumptions and implementation vary:

a) BGE defines design day conditions based on approximately a 1-in-51-year cold weather event, corresponding to an average temperature of about 2.7°F with a 15 mph wind speed.[17] BGE estimates design day demand using

[16] Regression models estimate expected demand based on historical relationships, but those estimates include uncertainty because actual demand may vary around predicted values. Higher statistical confidence levels use the upper end of that uncertainty range to add an additional safety margin and reduce the risk of underestimating peak demand.
[17] Direct Testimony of BGE Witness Brian M.W. Scheerer at 6, Exhibit BMS-2 at 3.

regression-based models of gas sendout[18] and a 99.9th percentile forecast under these conditions.[19] The modeling approach relies on historical weather data extending back to 1950 to define extreme conditions, while load data used to estimate demand relationships are based on daily sendout data from 2009 through 2025.[20] Historical load data are further adjusted (or "detrended") to reflect current customer characteristics, and multiple regression models are used and combined to estimate design day demand under the extreme conditions.[21]

b) WGL defines design day conditions based on a daily mean temperature of 5°F (60 heating degree days) and an average wind speed of 17 mph. WGL developed these design day weather conditions primarily through engineering judgment—using "professional knowledge, experience, and logical reasoning"—rather than through a clearly defined statistical return period or explicit probabilistic weather standard.[22] WGL estimates design day demand using a regression-based approach applied to a subset of historical peak demand observations, specifically the Top 25 Sendout Days.[23] Notably, these Top 25 Sendout Days (of which the oldest data is

[18] Gas sendout represents the total volume of gas delivered into the distribution system to meet customer demand.
[19] BGE Witness Scheerer Direct at 10:1-10, Exhibit BMS-2 at 7-8.
[20] BGE Witness Scheerer Direct, Exhibit BMS-2 at 4–5.
[21] BGE Witness Scheerer Direct, Exhibit BMS-2 at 5–6.
[22] WGL response to OPC DR 4-1(b).
[23] Direct Testimony of WGL Witness Kevin M. Murphy, Exhibit WGL-KMM-2 at 5–7.

from January 23, 2005), exclude days that experienced design day conditions, because earlier extreme cold days occurred when system loads were lower than today.[24] As a result, the dataset reflects more recent high-sendout days driven by system growth rather than extreme weather. WGL adjusts these observations to reflect consistent design day conditions, including application of a "conservation factor" to account for reduced load diversity (i.e., less variation in customer usage patterns as more customers heat heavily at the same time) under extreme cold conditions.[25] WGL averages the adjusted sendout values to estimate design day demand, and develops a 95 percent confidence interval around the estimate using statistical methods.[26] WGL also applies a reserve margin of approximately 5 to 6.5 percent above forecasted design day demand to ensure system reliability.[27]

c) Columbia defines its design day temperature (–1°F) based on historical observations of annual minimum temperatures and a probabilistic analysis corresponding to a 10 percent risk (1-in-10) of colder conditions.[28] Columbia estimates design day demand using regression-based models of daily throughput that incorporate variables such as temperature, lagged

[24] WGL response to OPC DR 1-3(a); Exhibit WGL-KMM-2 at 5.
[25] WGL Witness Murphy Direct, Exhibit WGL-KMM-2 at 7–9.
[26] WGL Witness Murphy Direct, Exhibit WGL-KMM-2 at 7–9.
[27] WGL Witness Muphy Direct, Exhibit WGL-KMM-2 at 18.
[28] Columbia response to 9707 Special Master 1-001 Attachment B – CMD Strategic Gas Supply Plan 2026-2030 ("Columbia SGSP"), at 20–21, Exhibit III.3.

temperature effects, and wind speed.[29] Columbia calibrates these regression models using actual throughput data from only the current and prior winter (December–February period), in order to reflect the current customer base.[30] The company then applies the resulting relationships to the design day temperature to estimate peak demand.[31]

These gas companies estimate design day demand by applying modeled relationships between temperature and demand to extreme weather conditions, often supplemented by adjustments to historical peak observations. These relationships are typically calibrated using historical data that do not include observed system performance under comparable design day conditions and, in some cases, rely on a limited range of recent operating conditions. As a result, these estimates rely exclusively on statistical modeling and assumptions, rather than observed system performance under comparable extreme conditions.

B. Reliance on Historical Trends in Gas Demand Forecasting

Q. How do gas utilities rely on historical trends in developing demand forecasts?

A. BGE, WGL, and Columbia primarily develop demand forecasts by estimating historical relationships between gas consumption and key drivers such as weather, economic activity, and customer growth. Using statistical methods applied to historical data, they quantify how gas demand has changed in response to these

[29] Columbia SGSP at 22; Columbia response to 9707 Special Master 1-001 Attachment A.
[30] Columbia response to OPC DR 1-003.
[31] Columbia response to OPC DR 1-004.

factors over time and then apply those estimated relationships to assumed future conditions—such as normal weather for annual demand, extreme weather for design day demand, and expected economic activity and customer growth—to project future gas demand.

Q. What are the implications of relying on historical trends for forecasting?

A. Because these approaches are grounded in historical data, projected demand tends to evolve gradually over time and reflects past consumption patterns. As a result, the responsiveness of forecasts to more recent developments depends on the extent to which those developments are reflected in historical data used for model estimation. This approach inherently assumes that historical trend will continue and does not fully account for potential structural changes—such as shifts in technology adoption or policy—that are not yet reflected in the historical data.

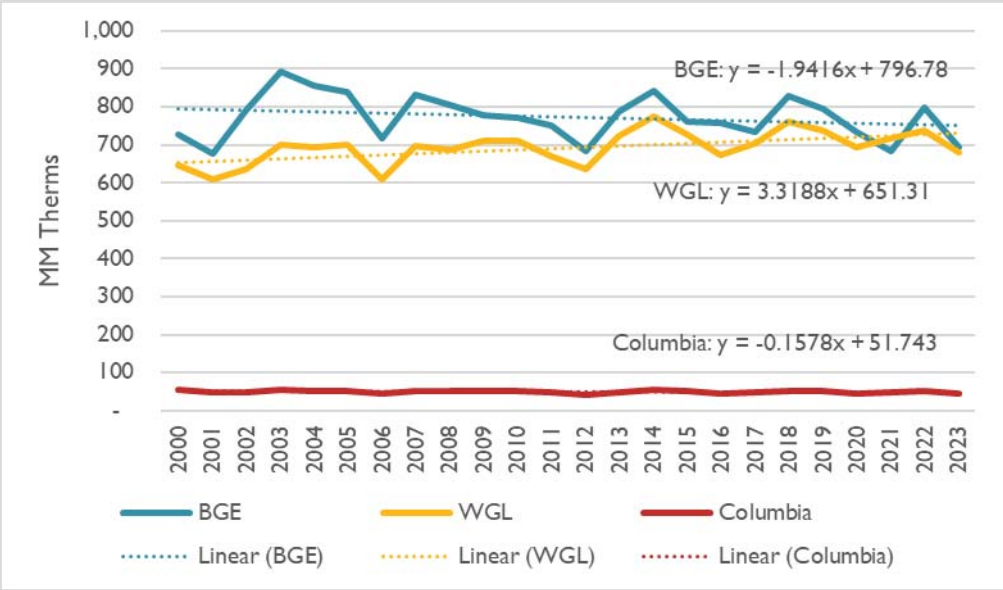
Q. What would future gas consumption look like if it were projected based solely on historical trends?

A. If historical gas consumption trends alone were extended forward, without considering other drivers or structural changes, future gas demand would appear broadly similar to past patterns and would include modest declines in usage per customer associated with historical energy efficiency improvements and warming trends. **Figure 1** shows that historical annual gas throughput for BGE, WGL, and Columbia's residential and commercial customers has remained relatively stable in aggregate over the past two decades, with no evidence of sustained or significant growth in overall gas consumption. Because local gas distribution

systems primarily serve residential and commercial customers, trends in these sectors provide important context for broader distribution system demand patterns, even though design day demand forecasts remain more directly relevant for infrastructure sizing. Within this aggregate pattern, BGE and Columbia exhibit slight long-term declines in annual gas use—approximately 0.3 percent per year—while WGL shows only modest growth of roughly 0.5 percent per year. **Figure 2** presents a broader review of total gas consumption across all customer sectors—including residential, commercial, industrial, and vehicle use—for BGE, WGL, and Columbia. These trends likewise indicate limited overall growth at the aggregate level, but with important variation across utilities. In particular, BGE shows a significantly more pronounced and sustained long-term decline in total gas consumption compared to the residential and commercial trends shown in **Figure 1**, while WGL continues to exhibit modest growth and Columbia remains relatively stable at a smaller scale. This difference suggests that declines in BGE's total gas demand are being driven by reduced industrial sector sales sectors, beyond just declines for residential and commercial customers. Taken together, these results indicate that Maryland's overall gas demand has not experienced sustained long-term growth, reflecting a combination of declining, stable, and modestly increasing trends across utilities. These trendlines further suggest that, absent major structural market or policy changes, a forecast based solely on historical data would largely project the future to resemble the past: relatively

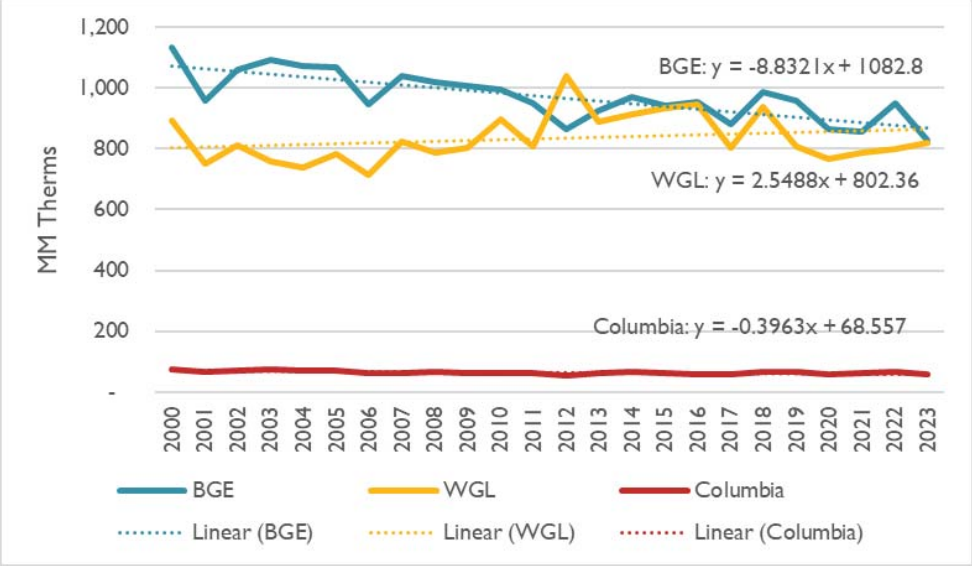
stable gas consumption with gradual, incremental change rather than substantial expansion or contraction.

Figure 1. Gas Consumption Trends for Combined Residential and Commercial Sectors for BGE, WGL, and Columbia



Source: EIA-176 database. Available at: https://www.eia.gov/naturalgas/ngqs/#?year1=2021&year2=2024&company=Name.

Figure 2. Total Gas Consumption Trends for All Sectors for BGE, WGL, and Columbia

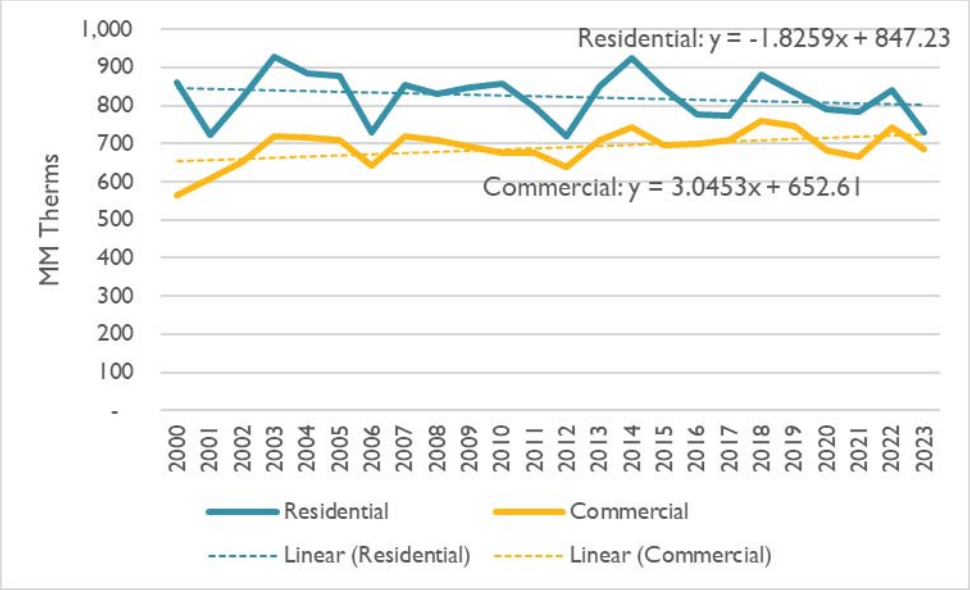


Source: EIA-176 database. Available at: https://www.eia.gov/naturalgas/ngqs/#?year1=2021&year2=2024&company=Name.

Q. Have you observed any distinct consumption trends by customer class?

A. Yes. Combined residential gas consumption for BGE, WGL, and Columbia has remained relatively stable since 2000, with a modest overall declining trend, while combined commercial consumption has generally increased over the same period, as shown in **Figure 3** below. As shown in **Figure 1**, these differing residential and commercial sector-specific trends largely offset one another over time on an aggregate level across the three gas utilities.

Figure 3. Residential and Commercial Total Consumption Trends for BGE, WGL, And Columbia

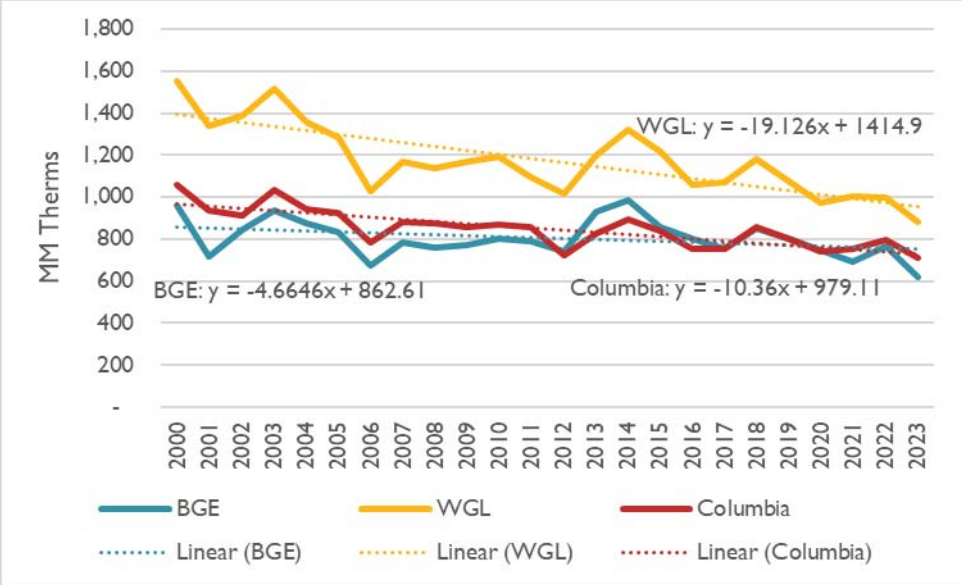


Source: EIA-176 database.

Notably, residential consumption per customer has been steadily declining since 2000 for WGL, BGE, and Columbia, as shown in **Figure 4**. WGL has experienced the greatest decline in residential consumption per customer since 2000, followed by Columbia. These trends likely reflect a combination of factors,

including energy efficiency improvements, electrification, and warmer weather trends occurring alongside relatively stable total residential consumption.

Figure 4. Residential Consumption per Customer Trends for WGL, BGE, And Columbia



Source: EIA-176 database.

Q. What are the implications of declining use per customer for residential customers?

A. Declining gas consumption per customer—particularly within the residential sector, which represents a large share of gas utility customers and overall throughput—places upward pressure on gas rates, all else being equal, because utilities must recover a substantial share of fixed infrastructure and system costs over lower average throughput per customer. This pressure would be amplified if gas companies continue to increase their capital investments while average customer usage declines.

Q. While historical trends provide useful context, are there important limitations to relying on them alone for long-term forecasting?

A. Yes. While historical trend-based approaches provide a consistent and widely used framework for understanding how gas demand has evolved over time, relying primarily on historic trends no longer provides a sufficiently reliable basis for prudent long-term forecasting when recent and future market conditions diverge materially from historical experience. Historical approaches do not fully capture structural changes that are not yet reflected in historical data, particularly when such changes are recent or emerging. The limitations are particularly important in the current context of rapid electrification and evolving policy, as discussed further in Subsection C and Section III.

C. Emerging Market Trends and Policy Drivers of Gas Demand

Q. What are the emerging trends and the current and future policies that should be incorporated into the companies' demand forecasts?

A. Emerging trends of heating equipment stock in Maryland households indicate a growing preference for electric heating equipment over gas, as discussed below. This trend likely reflects broad market and technology developments—including improvements in cold-climate air-source heat pumps, declining equipment costs, evolving consumer preferences, and national electrification trends. Existing policies such as EmPOWER and Maryland's Building Energy Performance Standards, along with proposed and forthcoming policies such as a Clean Heat Standard, a Zero-Emission Heating Equipment Standard, and other local and

regional policies, are likely to accelerate these trends substantially and could materially reshape the future composition of Maryland's heating equipment stock and gas demand trajectory beyond what historical trends alone would suggest.

Importantly, Maryland's EmPOWER programs are already evolving beyond traditional energy efficiency by increasingly incentivizing direct fuel switching to electric heat pumps, providing observable evidence that current policy implementation is already beginning to shift heating demand away from natural gas even before more aggressive policies take effect.

Q. What emerging trends have you observed in heating equipment in Maryland households?

A. The number of households in Maryland with electricity as their primary heating source is increasing faster than the number of households with gas as their primary heating source (Table 1). This disparity in growth rates indicates that electricity is capturing a growing share of Maryland's heating market and that household heating technology preferences are already shifting in ways that will affect future gas demand.

Table 1. Number of Maryland Households by Primary Heating Equipment

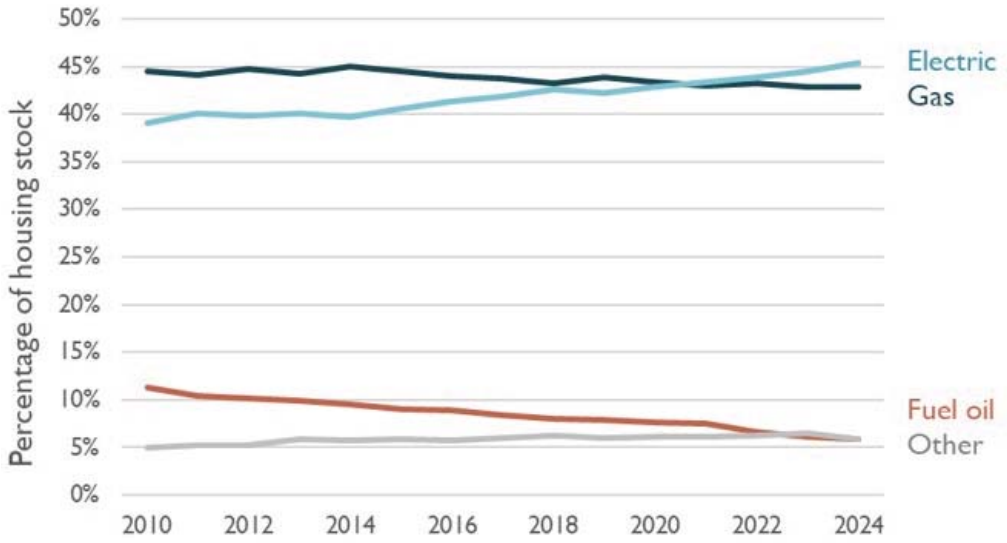
	2015	2024	Annual growth rate
Utility gas	968,764	1,029,007	0.61%
Electricity	883,862	1,089,518	2.11%
Fuel oil	197,050	140,292	-3.34%
Other*	128,258	142,577	1.06%
Total	2,177,934	2,401,394	

Source: U.S. Census Bureau, American Community Survey. Available at:
https://data.census.gov/table/ACSDP1Y2024.DP04?g=040XX00US24
Note: (*) includes bottled or tank gas such as propane, coal, coke, wood, solar energy, and other fuel sources.

From 2015 to 2024, the percentage of total Maryland households with gas heating equipment as their primary heating source fell by 0.4 percent annually, while the share of households with electric heating equipment rose by 1.1 percent annually (**Figure 5**).[32] Although the total number of gas-heated homes continued to grow modestly over this period, that growth slowed substantially relative to electric heating, which expanded much more rapidly. Around 2021, households using electric heating surpassed households using gas heating for the first time. These trends indicate a clear shift toward electric heating equipment relative to gas, with electricity capturing a growing share of new and replacement heating demand. While these recent shifts appear to be gradual, future transitions are likely to occur more rapidly than past trends alone would suggest as market drivers continue to strengthen, existing policies are implemented, and forthcoming policies are adopted.

[32] Source: U.S. Census Bureau. American Community Survey. Available at: https://data.census.gov/table/ACSDP1Y2024.DP04?g=040XX00US24

Figure 5. Share of Maryland Households by Primary Heating Equipment



Source: U.S. Census Bureau, American Community Survey. Available at: https://data.census.gov/table/ACSDP1Y2024.DP04?g=040XX00US24.

Additionally, in *An Assessment of Electrification Impacts on the Maryland Electric Grid*, the Brattle Group found that 27 percent of Maryland households use heat pumps as of 2022.[33] This includes cold climate air source heat pumps ("ASHPs"), ground source heat pumps, ASHPs with electric resistance backup, and ASHPs with fuel backup.

Q. Please describe Maryland's existing policies that impact gas demand.

A. Maryland's Building Energy Performance Standards ("BEPS"), created under the Climate Solutions Now Act of 2022, requires most buildings 35,000 square feet or larger to reduce their direct GHG emissions by 20 percent by 2030 and achieve

[33] The Brattle Group. 2023. *An Assessment of Electrification Impacts on the Maryland Electric Grid.* Available at: https://psc.maryland.gov/wp-content/uploads/Corrected-MDPSC-Electrification-Study-Report-2.pdf (attached as Exhibit KT-4).

net-zero by 2040.[34] The policy also has certain energy use intensity requirements that could help mitigate increases in electric peak demand. According to the Maryland Department of the Environment ("MDE"), this policy is expected to reduce GHG emissions by approximately 18 MMTCO2e from 2025 to 2050.[35]

The Maryland EmPOWER program, created through the Maryland Energy Efficiency Act of 2008, offers incentives to help customers save energy and money, while reducing GHG emissions. EmPOWER is currently administered by gas and electric companies, including WGL and BGE.[36] EmPOWER includes incentives for weatherization, efficient appliances, and more recently, BGE began offering incentives that explicitly support fuel switching. BGE offers generous rebates for electrification measures, especially heat pumps. Under its Home Performance with ENERGY STAR program, rebates can reach up to $10,000 or 75 percent of project cost, and up to $15,000 or 75 percent for projects that replace combustion-fuel equipment with a qualifying electric heat pump.[37] Recent EmPOWER program data also indicates that EmPOWER utilities collectively supported more than 17,000 heat pump installations in 2025, including more than

[34] Maryland Department of the Environment. "Maryland Building Energy Performance Standards (BEPS)," accessed April 21, 2026. Available at: https://energy.maryland.gov/Pages/BuildingEnergyPerformance.aspx?utm_source=chatgpt.com.
[35] Maryland Department of the Environment, "Buildings," accessed April 21, 2026. Available at: https://mde.maryland.gov/programs/air/ClimateChange/CPRP/Pages/Buildings.aspx.
[36] Maryland Energy Administration. n.d. "EmPOWER Maryland." Available at: https://energy.maryland.gov/pages/facts/empower.aspx. HB 1532, still awaiting the governor's signature, would repeal the requirement that gas companies participate in the EmPOWER program.
[37] BGE. "Rebates with Home Performance." Available at: https://bgesmartenergy.com/residential/help-me-save/home-performance/rebates.

2,100 air-source heat pumps specifically installed through fuel-switching applications.[38] These fuel-switching incentives are particularly significant because they provide direct observable evidence that Maryland's existing utility-administered programs are already beginning to reduce future gas demand through electrification, rather than solely through efficiency improvement within continued gas use. These results suggest that Maryland's utility-administered efficiency programs are already moving beyond traditional energy efficiency toward direct electrification and fuel substitution, even before more aggressive standards are implemented.

Q. Please describe Maryland's proposed and forthcoming policies that will impact gas demand.

A. A 2024 Executive Order by Governor Wes Moore directed MDE to develop a Zero-Emission Heating Equipment Standard ("ZEHES") and a Clean Heat Standard ("CHS") to support building sector decarbonization.[39] MDE is in the process of developing a ZEHES and CHS, and is expected to adopt rules for each program sometime in 2027.[40] If implemented as currently proposed, the ZEHES

[38] VEIC. 2026. *Evaluation of 2025 Q3–Q4 EmPOWER Maryland Semi-Annual Program Reports*. Prepared for the Maryland Office of People's Counsel, Case No. 9705. at 46. Available at: https://opc.maryland.gov/Portals/0/Files/Publications/20260415%20-%20OPC%20Comments%20on%20Q3-Q4%20Semi-Annual%20Reports%20-%20CN%209705.pdf.
[39] Executive Order 01.01.2024.19, Governor Moore, Implementing Maryland's Climate Pollution Reduction Plan, June 4, 2024. Available at: https://governor.maryland.gov/Lists/ExecutiveOrders/Attachments/52/EO%2001.01.2024.19%20Leadership%20by%20State%20Government-%20Implementing%20Maryland%27s%20Climate%20Pollution%20Reduction%20Plan_Accessible.pdf.
[40] Maryland Department of the Environment, "Clean Heat Rules," accessed April 21, 2026. Available at: https://mde.maryland.gov/programs/air/ClimateChange/Clean-Buildings/Pages/Clean-Heat-Rules.aspx.

would require new heating equipment installed in Maryland households to produce zero on-site emissions beginning later this decade and rely on natural stock turnover to transition buildings to non-emitting heating equipment. The CHS, as currently proposed, would require gas companies, as well as oil and propane importers, to reduce their GHG emissions according to a schedule set by MDE. Measures for reducing emissions can include "installing zero-emissions heating equipment, weatherizing buildings, and providing cleaner fuels."[41] Additionally, Montgomery County passed a bill that requires all new construction and major renovation projects to be all electric, banning the installation of gas appliances.[42]

Q. Has any Maryland state agency evaluated the potential greenhouse gas reductions associated with current and proposed building-sector climate policies?

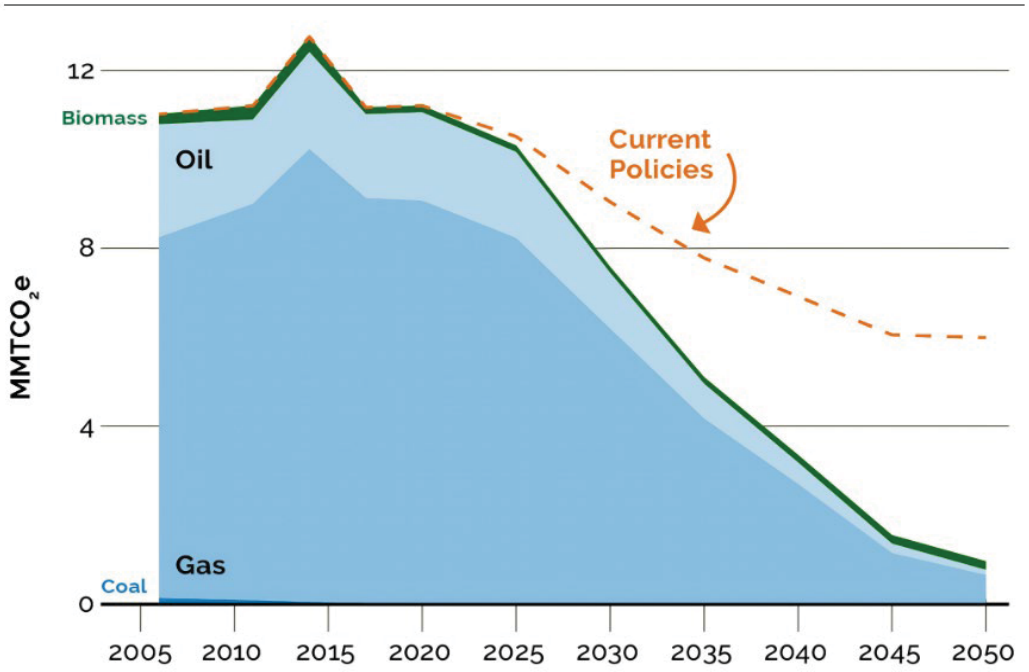
A. Yes. MDE, through its Climate Pollution Reduction Plan ("CPRP"), evaluated the long-term building-sector emissions impacts of Maryland's climate policies. As shown in **Figure 6**, MDE projects that under its broader building decarbonization pathway, direct emissions from natural gas use in buildings—the largest current source of building-sector fossil fuel emissions—decline from approximately 8

[41] Maryland Department of the Environment, "Clean Heat Rules," accessed April 21, 2026. Available at: https://mde.maryland.gov/programs/air/ClimateChange/Clean-Buildings/Pages/Clean-Heat-Rules.aspx; Maryland Department of the Environment. 2024. "Clean Heat Rules: Clean Heat Standard & Zero-Emission Heating Equipment Standard," November 21, 2024. Available at: https://mde.maryland.gov/programs/air/Climate-in-md/Documents/Cleanheatrules/Clean%20Heat%20Rules%20Nov%2021%20Webinar.pptx.pdf

[42] Montgomery County Council, Bill 13-22: Buildings—Comprehensive Building Decarbonization (Mar. 13, 2023). Available at: https://www.naiopmd.org/wp-content/uploads/2024/10/All-Electric-Building-Code-CB-13-22-Enacted-March-13-2023.pdf.

MMTCO2e today to roughly 1 MMTCO2e or less by 2050, representing an approximate 85 percent or greater reduction. By contrast, under current policies alone, MDE projects direct building-sector emissions to decline to approximately 6 MMTCO2e by 2050, representing roughly a 25 percent reduction from current levels.[43]

Figure 6. MDE's Analysis of CPRP Building-Sector Pathways: Projected Direct Building Emissions by Fuel Under Current Policies vs. Broader Decarbonization Policies



Source: Maryland Department of the Environment, "Buildings," accessed April 21, 2026. Available at: https://mde.maryland.gov/programs/air/ClimateChange/CPRP/Pages/Buildings.aspx.

MDE's analysis therefore indicates that Maryland's current policies are already expected to drive significant, long-term declines in natural gas use in buildings, while proposed and forthcoming climate policies would lead to even greater

[43] Maryland Department of the Environment, "Buildings," accessed April 21, 2026. Available at: https://mde.maryland.gov/programs/air/ClimateChange/CPRP/Pages/Buildings.aspx.

reductions. This suggests that gas demand forecasting methodologies that rely primarily on historical consumption trends are likely to materially understate the long-term impacts of Maryland's broader climate policy trajectory.

III. Improving Gas Demand Forecasting Through Better Market, Policy and Design Day Assumptions

Q. Please provide an overview of this section of your testimony.

A. In this section, I evaluate how current gas demand forecasting methodologies address emerging market trends, policy developments, and design day planning assumptions, and I identify areas where these approaches may materially overstate future gas demand or infrastructure needs. *This section primarily addresses issues 3 and 12 identified in Order No. 91791.*[44]

Q. Have you identified any significant concerns with the utilities' load forecasting methodologies?

A. Yes, I have significant concerns with the way the gas companies' load forecasting methodologies account for the impacts of emerging market trends and policies. I also have a concern about how the gas companies estimate design day gas demand. Because gas planning is fundamentally a risk-management exercise under uncertainty, the gas companies' forecasting methodologies should not rely solely on historical continuity when emerging and observable market, technology, and

[44] These issues are as follows:
(3) What policies, guidelines, or regulations, if any, should be adopted to ensure that future natural gas company planning practices adequately address the State's climate goals?
(12) How should future technological innovations, demand response programs, more efficient appliances, and other mechanism, be addressed in gas company planning?

policy trends increasingly point to material changes in demand trajectories. I will address each of these concerns in detail below.

A. The Commission Should Direct Gas Companies to Better Account for Emerging Market Trends in Demand Forecasting.

Q. How should gas utilities incorporate emerging market trends into gas demand forecasting?

A. The Commission should direct gas utilities to incorporate the impacts of observable emerging market trends—such as recent shifts in heating equipment preferences, electrification adoption, and changing consumer fuel choices—into their demand forecasts. In practice, this means utilities should distinguish between (1) baseline market evolution driven by current technology adoption, customer behavior, and existing market momentum, and (2) additional demand changes that may result from implementing existing policies, or new or future policy interventions.

Q. Please discuss limitations of the gas companies' regression-based forecasting methodologies in capturing the impact of emerging market trends.

A. BGE, WGL, and Columbia's regression-based forecasting methodologies rely primarily on historical relationships between gas consumption and key drivers such as weather, economic activity, and customer growth. While these approaches are useful under relatively stable conditions, they have important limitations in capturing emerging market trends that reflect structural changes in the energy system, including increasing electrification, changing customer technology

adoption, shifting fuel economics, and evolving building and policy environments that may fundamentally alter future gas demand.

First, regression-based models that draw on long-term historical data inherently place weight on data over the whole term of the sample data. As a result, recent developments—such as the accelerating adoption of heat pumps—have a limited influence on the estimated relationships, even if those developments are expected to become more prevalent in the future. Because these approaches rely on historical consumption and gas customer count data, they may underrepresent or delay the impact of trends that have only recently begun to emerge. This limitation is particularly important in the current context, where recent trends in electrification are likely to play a dominant role in shaping future demand, despite having a relatively small footprint in the historical data used for model estimation.

Second, the way that the gas utilities use these models generally assumes that long-term past relationships between gas demand and its drivers will continue into the future. This assumption may not hold in the presence of policy-driven and technology-driven shifts, such as building electrification, changes in fuel preferences, and evolving consumer choices. As a result of these limitations, regression-based forecasts understate the pace and magnitude of changes in gas demand associated with emerging trends, particularly in periods of rapid market transformation. This risk is especially important in Maryland because existing

market trends are already being reinforced by current utility-administered programs such as EmPOWER, which now increasingly support direct fuel switching to heat pumps, thereby accelerating structural demand changes beyond what historical datasets may fully capture.

Q. How can BGE, WGL, and Columbia improve their demand forecasting methodologies to better reflect emerging market trends?

A. I recommend that the Commission require the gas companies to:

a) Supplement traditional regression-based forecasting methods with forward-looking analyses that explicitly incorporate recent developments in heating equipment adoption, customer heating technology choices, electrification, and fuel-switching behavior, particularly where emerging trends are likely to accelerate beyond what is reflected in long-term historical data. More specifically, I recommend the Commission require gas companies to use recent data on heating equipment installations, replacements, and fuel choices—including heat pump adoption rates and heating system selections by fuel type—to estimate expected rates of full fuel switching, partial electrification (e.g., hybrid heating systems), and other structural shifts in heating demand.

b) Apply these market trend analyses to both projected gas customer counts and usage-per-customer assumptions by distinguishing between installations that fully displace gas usage, partially reduce gas consumption, or do not materially affect gas demand, thereby improving the ability of forecasts to reflect structural changes in the energy market. As discussed in Ms. Napoleon's testimony, the Commission should require the gas companies to track and report on customer electrification.[45]

[45] Direct Testimony of OPC Witness Alice Napoleon at 43.

This type of approach differs from conventional regression-based methods in that it places greater weight on recent market trends that I expect will continue and accelerate, rather than relying solely on long-term historical relationships. As a result, it provides a more forward-looking representation of structural changes in heating demand and can improve the accuracy and relevance of demand forecasts in a rapidly evolving building energy landscape.

B. The Commission Should Direct Gas Companies to Conduct Scenario-Based Demand Forecasting to Account for Current and Emerging Policy Impacts.

Q. Please discuss the utilities' approach to policy impacts.

A. The gas companies all take a broadly similar approach to incorporating the impacts of new policies (e.g., electrification, efficiency, and decarbonization): they do not explicitly model these impacts prospectively, and instead rely on historical data to capture such effects only after they are reflected in observed customer behavior or throughput.

Q. Please describe how the gas companies account for policy impacts on their demand forecasting.

A. As an example, BGE explains that policy-related factors—such as electrification, fuel switching, and energy efficiency—are reflected in its forecasts only to the extent they are embedded in observed customer behavior. BGE states that these factors are considered only insofar as they are "inherent in actual observed

customer behavior."[46] BGE's approach is consistent with its design day methodology, which relies on statistical models updated annually using historical load data to capture "changes in customer behavior and customer growth trends."[47] BGE further emphasizes that planning must rely on "known and available data and not … assumptions that have not come to fruition,"[48] and that adjustments will occur only if "meaningful and sustained" changes are realized in observed demand.[49]

WGL similarly emphasizes reliance on observed demand trends in its forecasting approach. WGL witness Kevin M. Murphy states that the firm design day demand forecast is "grounded in actual observed firm customer gas usage behavior on cold days as well as observed trends in firm new meter additions,"[50] and that the company "adopts changes in firm design day based on observed demand trends."[51] The forecast is based on "observed firm customer counts, usage data, and weather from the coldest days of recent winters."[52] WGL also makes clear that it does not rely on unobserved future changes, stating that planning "cannot be based on assumptions that gas demand will evaporate without observed

[46] BGE response to OPC DR 1-05.
[47] BGE Witness Scheerer Direct at 9:8.
[48] BGE Witness Scheerer Direct at 22:22-23.
[49] *See* BGE Witness Scheerer Direct at 23:15-17.
[50] WGL Witness Murphy Direct at 17:6–8.
[51] WGL Witness Murphy Direct at 17:9–12.
[52] WGL Witness Murphy Direct at 17:19–20.

evidence" and that it "cannot cut back … based on the assumption of future widespread electrification that has not been observed."[53]

Columbia provides the most explicit description of how these effects are treated in both design day and annual forecasts. For design day demand, Columbia explains that efficiency improvements, electrification, and policy impacts are "indirectly captured to the extent that any impacts… may have had on that historical throughput," and that "any changes, including to any government policies … are being indirectly captured to the extent it is shown in historical throughput."[54] For annual demand forecasts, Columbia states that electrification and policy impacts were "not considered when developing the forecast," and that any measurable historical effects are simply "carried into the forecast period at the same rate." [55]

Q. What are the key limitations of relying on historical gas demand to capture the impacts of new and emerging policies?

A. First, Maryland has adopted—and continues to develop—a range of policies and programs specifically designed to accelerate building electrification and reduce reliance on natural gas. As discussed earlier in my testimony, these include the Building Energy Performance Standards, EmPOWER Maryland's growing fuel-switching and heat pump incentives, and proposed or forthcoming policies such as

[53] WGL Witness Murphy Direct at 71:21-23 to72:1-2.
[54] Columbia response to OPC DR 1-14.
[55] Columbia response to OPC DR 1-19.

a CHS, a ZEHES, and local initiatives such as Montgomery County's all-electric building codes. However, because many of these policies are relatively recent or not yet implemented, their impacts are not yet reflected in historical gas demand data. As a result, approaches that rely primarily on historical relationships will systematically understate the magnitude and pace of expected future changes, particularly because recent structural trends—such as accelerating heat pump adoption and policy-driven electrification—are given relatively little weight compared to long-term historical patterns.[56]

Second, because gas infrastructure planning involves long-lived capital investments, the energy sector's current structural transition creates heightened planning risk if demand forecasting methodologies remain primarily backward-looking. Waiting for policy impacts to fully materialize in historical data before adjusting demand forecasts increases the risk that infrastructure and gas supply planning decisions will become increasingly misaligned with future demand. This delayed recognition of structural demand decline increases the likelihood of overbuilding gas infrastructure and supply resources, creating substantial risk of stranded or underutilized assets, particularly for long-lived investments such as

[56] While the gas companies' regression models are fundamentally grounded in historical relationships, they do incorporate certain forecasted external inputs, such as employment projections and NYMEX monthly gas price forecasts, when estimating future demand. Notably, however, while these methodologies incorporate forward-looking economic assumptions, they generally do not apply similarly forward-looking assumptions regarding policy- or market-driven structural market changes—including electrification, fuel switching, or emerging regulatory requirements—even where such factors may materially alter future gas demand.

pipeline capacity and distribution system upgrades. Given the long planning horizons and capital-intensive nature of gas infrastructure, reliance on backward-looking indicators is increasingly insufficient to support prudent planning decisions.

Taken together, these limitations are likely to result in demand forecasts that overestimate future annual gas use and design day demand, which may in turn support continued or expanded investment in gas infrastructure that may not be needed over the long term. Such overinvestment may contribute to unnecessary capital expenditures, stranded assets, higher customer rates, and increased customer bills, with potentially significant impacts on affordability and equity, particularly as the remaining gas customers face rising rates over time as customers who can afford to do so electrify. In a period of structural market and policy transition, reliance on delayed historical recognition alone no longer constitutes prudent long-term planning. Moreover, current market trends, existing utility-administered fuel-switching incentives through EmPOWER, and forthcoming climate policies increasingly indicate slowing gas demand growth and reduced reliance on gas heating. These trends mean future annual gas demand and design day demand are highly likely to be materially lower than traditional historical-trend forecasting methodologies currently project over time.

Q. Are you aware of any gas utilities that explicitly incorporate the impacts of market trends or new and emerging policies into their demand forecasts? If so, please describe their approaches.

A. Yes. Public Service Company of Colorado ("PSCo") d/b/a Xcel Energy in Colorado and Northwest Natural in Oregon and Washington are incorporating the impacts of emerging market trends and new state policies in their load forecasts.

PSCo developed a customer growth forecast for its Mountain Energy Project that explicitly considers the impacts of market-driven electrification in addition to its energy efficiency programs (the Demand Side Management and Beneficial Electrification plan).[57] PSCo used this policy- and market-informed customer forecast to develop its design day peak demand forecast.

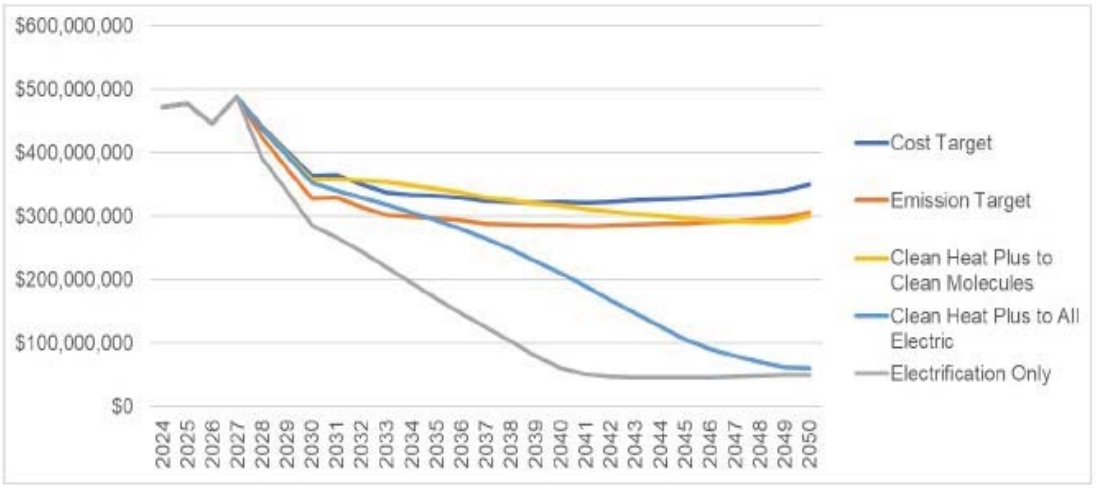
Consistent with this broader forward-looking planning approach, in its 2023 Clean Heat Plan, PSCo also developed long-term capital investment forecasts based on multiple demand scenarios (See **Figure 7**). In developing its investment forecasts for each scenario, "the Company assumed that the baseline capital forecast would be reduced proportionately to decreases in peak demand, " explaining that this approach "reflects the concept that some customers will fully electrify their loads and be disconnected from the system, thus reducing the size of our LDC system and reducing the amount of safety and integrity investments…"[58]

[57] Jones, Grace K. 2025. *Direct Testimony of Grace K. Jones (Rev. 1),* Hearing Exhibit 102, Colorado Public Utilities Commission, Proceeding No. 25A-0044EG, at 50. Available at: https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Search.

[58] Ihle, Jack W. 2023. *Supplemental Direct Testimony of Jack W. Ihle*, Hearing Exhibit 110, Colorado Public Utilities Commission, Proceeding No. 23A-0392EG, at 23. October 2023.Available at: https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_810274&p_session_id=.

As shown in **Figure 7**, PSCo's analysis indicates that under higher-electrification scenarios, projected gas infrastructure capital investments decline substantially over time relative to baseline scenarios, demonstrating how explicit consideration of emerging policies and market trends can materially affect long-term gas system planning.

Figure 7. Public Service Company of Colorado 2024–2050 Capital Investments by Scenario



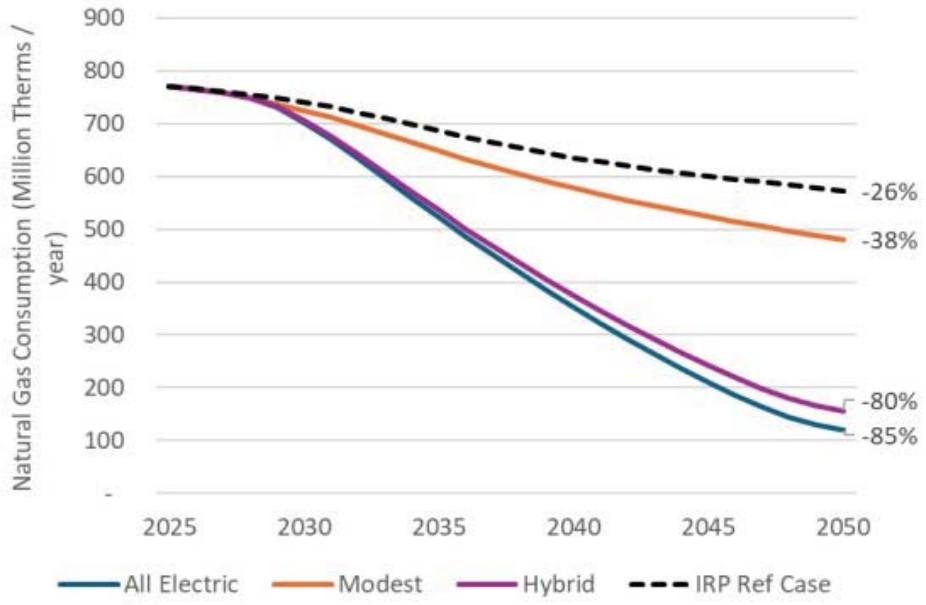
Source: Ihle, Jack W. 2023. *Supplemental Direct Testimony of Jack W. Ihle*, Hearing Exhibit 110, Colorado Public Utilities Commission, Proceeding No. 23A-0392EG, Figure JWI-SD-3.

As another example, in its 2025 Integrated Resource Plan, Northwest Natural developed three gas demand scenarios that account for state emission-reduction requirements and building electrification trends in Oregon and Washington. The Modest Electrification scenario aligns with the Northwest Energy Efficiency Alliance's Residential Building Stock Assessment and electric

utility building electrification forecasts.[59] This scenario assumes that half of new residential construction will adopt electric space and water heating by 2035, while only a small fraction of current gas customers will convert to heat pump space and water heating by 2030.[60] The Hybrid Electrification Scenario assumes that 65 percent of space heating sales are electric with gas backup by 2030 and that all space and water heating in new residential construction will be electric with gas backup by 2035.[61] Under this scenario, gas consumption declines by approximately 80 percent by 2050 relative to 2025,[62] while customer count declines by only about 13 percent.[63] The Full Electrification Scenario has similar adoption trajectories to the Hybrid scenario, but it assumes customers adopt all-electric equipment and terminate gas service.[64] Under this scenario, gas demand declines by approximately 85 percent and customer count declines by approximately 90 percent by 2050 relative to 2025.[65]

[59] NW Natural. 2025. *2025 NW Natural Integrated Resource Plan*, ("NW Natural 2025 IRP") at 10-8. Available at: https://www.nwnatural.com/about-us/rates-and-regulations/integrated-resource-plan.
[60] NW Natural 2025 IRP at 10-11.
[61] NW Natural 2025 IRP. at 10-11.
[62] NW Natural 2025 IRP. at 10-25.
[63] NW Natural 2025 IRP. at 10-27.
[64] NW Natural 2025 IRP. at 10-11.
[65] NW Natural 2025 IRP. at 10-25 and 10-27.

Figure 8. Change in NW Natural Residential and Commercial Gas Consumption by Scenario



Source: NW Natural, *2025 NW Natural Integrated Resource Plan* at 10-26.

Q. What is your recommendation for incorporating the potential impacts from new and forthcoming State climate policies?

A. I recommend that the Commission require the gas companies to:

a) Adopt forward-looking, scenario-based demand forecasting approaches that explicitly account for the potential impacts of existing policies and forthcoming state and local policies—including BEPS, CHS, ZEHES, EmPOWER Maryland's electrification incentives, and related measures—rather than relying primarily on historical trends to capture policy effects only after they materially appear in observed demand.

b) Develop multiple demand scenarios that reflect different levels of policy implementation and market response, including varying rates of electrification, energy efficiency adoption, fuel switching, and customer behavior, so that business-as-usual, policy-aligned, and accelerated transition pathways can be compared across a range of plausible futures.

c) Integrate these scenarios into planning and investment decisions by aligning demand forecasts with capital planning, gas supply planning, non-pipeline alternative evaluations, and assessments of how infrastructure needs change under different demand trajectories. This integration should include explicit modeling of key structural drivers—such as customer growth, usage per customer, electrification trends, fuel switching, gas demand response and other NPA programs—and stress-testing infrastructure needs against declining-demand scenarios to assess the risk of overinvestment and stranded assets, and adverse customer affordability impacts.

Overall, these changes would better align gas planning with Maryland's climate goals, improve long-term risk management, and support prudent infrastructure investment decisions.

C. The Commission Should Direct Gas Companies to Account for Realistic Space Heating Constraints in Design Day Forecasting.

Q. Please discuss the gas utilities' approach to design day load forecasting.

A. As discussed above, gas utilities such as BGE, WGL, and Columbia rely on broadly similar approaches to design day load forecasting that combine regression-based modeling of historical data with assumptions about extreme cold weather conditions. In general, these utilities estimate statistical relationships between daily gas demand (or sendout) and weather variables such as heating degree days and then extrapolate those relationships to extreme "design day" temperatures intended to represent rare cold-weather events. In other words, the utilities use

these extrapolated relationships to estimate peak gas demand under extremely rare weather conditions and develop design day demand forecasts.

Q. What are the key limitations of extrapolating design day load forecasts beyond observed temperature conditions?

A. Extrapolating demand beyond the range of observed temperatures introduces structural uncertainty, particularly because the relationship between temperature and gas demand is unlikely to remain linear at extreme conditions. Design day gas demand primarily reflects space heating demand in buildings. At very low temperatures, many heating systems operate at or near their maximum capacity, limiting further increases in demand.

As a result, gas demand is unlikely to increase indefinitely as temperatures decline. Instead, demand is more likely to approach a practical upper bound or plateau at very low temperatures, reflecting the maximum output of installed heating equipment. This physical constraint is not captured in regression-based models that extrapolate linearly beyond observed data.

Q. Please explain how HVAC systems are sized and their implications on gas peak demand.

A. Heating systems are sized based on established HVAC design standards and practices such as (a) ACCA Manual J, an HVAC load calculation methodology developed by the Air Conditioning Contractors of America Association, Inc.

("ACCA"),[66] and (b) weather data published by the American Society of Heating, Refrigerating and Air-Conditioning Engineers ("ASHRAE").[67] Manual J is also incorporated into the requirements of certain Maryland energy efficiency programs and local permitting practices, including the Maryland Department of Housing and Community Development's Energy Efficiency Program and Montgomery County's residential mechanical permit requirements, further reflecting its practical role as a recognized sizing benchmark.[68]

Manual J commonly relies on 99 percent heating design temperatures, representing weather conditions under which appropriately designed equipment can fully meet space heating loads for 99 percent of annual heating hours.[69] The U.S. Environmental Protection Agency's ENERGY STAR program also recommends the use of the 99 percent heating design temperature for residential HVAC sizing.[70]

---

[66] Air Conditioning Contractors of America (ACCA), *Manual J Residential Load Calculation*, https://www.acca.org/standards/technical-manuals/manual-j.
[67] ASHRAE, *Climatic Design Conditions 2009/2013/2017/2021*, https://ashrae-meteo.info/v2.0/.
[68] Maryland Department of Housing and Community Development Housing & Building Energy Programs. 2024. *Energy Efficiency Program Operations Manual*. Available at: https://dhcd.maryland.gov/Energy-Home-Repair/Documents/WAP/EnergyEfficiencyProgramOperationsManual.pdf?utm_source=chatgpt.com; Montgomery County. "Manual J Calculations for a Residential Mechanical Permit." Available at: https://www3.montgomerycountymd.gov/311/SolutionView.aspx?SolutionId=1-2AUCOJ&utm_source=chatgpt.com&AspxAutoDetectCookieSupport=1.
[69] Allison A. Bailes III. 2021. "Design Temperature vs. Degree Days." Available at: https://www.greenbuildingadvisor.com/article/design-temperature-vs-degree-days; HVAC DesignPros. 2014. "Manual-J HVAC Design Loads." Available at: https://hvacdesignpros.com/hvac-design-loads-manual-j/.
[70] U.S. Environmental Protection Agency. 2019. *ENERGY STAR Certified Homes Design Temperature Limit Reference Guide (2019 Edition)* at 1, https://www.energystar.gov/partner-resources/residential_new/working/hvac/hvac_designers/design_temp_limits.

The purpose of these standards is to ensure that heating systems can maintain indoor comfort during nearly all expected winter conditions while avoiding excessive oversizing for extreme cold events. Excessive oversizing can increase upfront costs and may contribute to operational inefficiencies such as more frequent cycling and reduced overall system performance.[71]

Because heating systems are typically designed around these industry-standard conditions, they have practical capacity limits. During extremely cold weather events beyond the design temperature, many systems operate at or near full capacity, and energy consumption may not continue increasing proportionally with falling temperatures. Instead, as a growing share of heating systems approach practical capacity constraints, aggregate gas demand growth is likely to diminish materially and may approach a practical upper bound, rather than continuing to increase proportionally with falling temperatures. This has important implications for gas peak demand forecasting, because regression-based extrapolations that assume continued linear growth in heating demand at increasingly extreme temperatures may overstate actual space-heating-related gas demand.

Q. Please compare the gas companies' design day temperatures with ASHRAE heating design temperatures.

A. Gas utility design day temperatures are generally more extreme than HVAC design temperatures used for equipment sizing. While HVAC systems are

[71] Whole Building Design Guide (WBDG). n.d. "High-Performance HVAC," National Institute of Building Sciences. Available at: https://www.wbdg.org/resources/high-performance-hvac.

typically designed to meet conditions that occur in approximately 99 percent of hours in a typical year, gas utilities often define design day conditions based on rarer events (e.g., 1-in-10, 1-in-20, or more extreme return periods). Although these metrics are not directly comparable, HVAC design temperatures reflect conditions that occur with some regularity each year, whereas gas utility design day conditions reflect rare extreme events across multiple years.

Table 2 compares the utilities' design day temperatures with ASHRAE 99 percent heating design temperatures. As shown, the gas companies' design temperatures are approximately 16°F to 17°F colder than the corresponding ASHRAE design temperatures.

Table 2. Comparison of Gas Companies' Design Day Temperature and ASHRAE 99% Heating Design Temperature

	BGE - Baltimore	WGL – D.C.	Columbia - Hagerstown
Utility design day temperature (F)	2.7	5	-1
ASHRAE 99% heating design temperature	19.7	21.0	15.9

Source: Exhibit BMS-2, at 3; Exhibit WGL-KMM-2 at 5; Columbia Response to OPC DR 1-016, Attachment D; and ASHRAE Climate Design Conditions. Available at: https://ashrae-meteo.info/v3.0/.
Note: ASHRAE updates its heating design temperatures every four years. The data presented in this table represent the average 99% design temperatures across the five most recent ASHRAE datasets since the 2009 edition.

In practice, some contractors may oversize heating systems relative to calculated design loads. However, industry standards such as ACCA's Manual S

limit the allowable degree of oversizing to maintain efficiency and performance.[72] To account for this effect, I apply a 20 percent oversizing factor to HVAC-based heating requirements[73] and derive corresponding design temperatures, as shown in **Table 3**. Using ASHRAE 99 percent heating design temperatures as a starting point, I first calculate daily heating demand in heating degree days relative to a 65°F baseline temperature[74] and then increase those heating requirements by 20 percent to reflect potential oversizing within ACCA Manual S limits. For example, for BGE, the ASHRAE 99 percent heating design temperature is 20°F, and thus the daily heating demand at this design condition is 45 heating degree days (65°F - 20°F) as shown in **Table 3**, and 54 heating degree days with a 20 percent oversizing factor (i.e., 45 heating degree days multiplied by 120 percent). I then calculate the corresponding colder outdoor temperatures that would produce those

[72] Air Conditioning Contractors of America (ACCA). *Manual S® – Residential Equipment Selection*, 3rd ed. Arlington, VA: Air Conditioning Contractors of America. Available at: https://www.acca.org/standards/technical-manuals/manual-s

[73] In practice, the degree of oversizing varies depending on building characteristics, contractor practices, and equipment availability. ACCA Manual S permits heating equipment capacity to exceed calculated design loads within specified limits, in certain cases up to approximately 140% of calculated heating load depending on equipment type and application. For modeling purposes, I apply a 20 percent oversizing factor (i.e., equipment sized at approximately 120% of calculated heating design load) as a moderate sensitivity assumption to evaluate how reasonable oversizing may affect aggregate heating system capacity across a diverse building stock. This assumption is broadly consistent with the 15% to 20% gas furnace oversize assumptions used in Xcel Colorado's demand-side management Technical Reference Manual, depending on methodology and application. See Public Service Company of Colorado. *2024–2026 Demand-Side Management & Beneficial Electrification Plan*, Hearing Exhibit 101, Attachment NCM-1, Proceeding No. 23A-0589EG, Appendix H (Technical Reference Manual), at 482, 574. Available at: https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Search.

[74] This is calculated by comparing the daily average temperature to 65°F, a commonly used baseline temperature for estimating how much heating demand exists on a given day. For example, if the daily average temperature is 15°F, the heating degree days would be 50 (65°F - 15°F).

adjusted heating degree day values. Using BGE's example again, I estimated approximately 10.6°F for the corresponding implied colder temperature by converting the adjusted heating requirement back into an outdoor temperature. As shown, the resulting implied design temperatures (10.6°F for BGE, 12.2°F for WGL, and 6.1°F for Columbia) remain significantly warmer than the gas utilities' design day temperatures, indicating that typical heating systems are generally not sized to meet those extreme conditions.

Table 3. Heating Requirements with A 20 Percent Oversizing Factor and Implied Heating Design Temperatures

	BGE	WGL	Columbia
ASHRAE 99% heating design temperatures (F)	20	21	16
Heating degree days	45	44	49
Heating degree days with a 20% oversizing factor	54	53	59
Implied heating design temperatures with a 20% oversizing factor	10.6	12.2	6.1

Note: ASHRAE temperatures and heating degree day values are rounded for simplicity; implied heating design temperatures are based on underlying unrounded calculations.

Q. What is the level of potential overestimation of design day demand by the gas companies, if we assume HVAC industry heating system sizing practices with a 20 percent oversizing factor?

A. **Table 4** compares heating requirements implied by gas utility design day temperatures with those based on HVAC industry practices, including a 20 percent oversizing factor. As shown, the utilities' assumptions result in heating requirements that are approximately 12 to 15 percent higher than those implied by HVAC sizing practices. These results suggest that utility design day assumptions materially exceed heating requirements implied by standard HVAC sizing

practices and therefore overstate space-heating-related peak demand, likely contributing to unnecessary investment in gas system infrastructure or peak gas supply resources.

Table 4. Expected Heating Degree Days - Gas Utility Practice vs. HVAC Industry Practice

	BGE	WGL	Columbia
Gas utility practices	62.3	60.0	66.0
HVAC industry practice, including 20% oversizing factor*	54	53	59
Overestimation by utility design day temperatures	15%	14%	12%

*Assumes temperatures based on ASHRAE heating design temperature + 20% oversizing

Q. Should design day temperatures be evaluated independently from other design day planning assumptions?

A. No. While design day temperatures are a critical driver of peak demand forecasts, they are only one component of broader design day planning methodologies. Additional assumptions—such as reserve margins, confidence intervals, or other planning assumptions—can also materially affect overall forecast outcomes. As a result, evaluating design day temperatures alone may understate the extent of conservatism embedded in overall design day demand forecasts. These findings also suggest that combining extreme design temperatures with additional planning assumptions may create cumulative conservatism beyond what is necessary for prudent reliability planning unless those assumptions are empirically validated both individually and in combination.

Q. What are your recommendations regarding the gas utilities' design day assumptions?

A. I recommend that the Commission require the gas companies to modify their design day assumptions and peak demand forecasting practices as follows:

a) Re-evaluate whether current design day temperatures and associated peak demand assumptions materially exceed realistic heating requirements implied by HVAC industry sizing practices, practical heating system capacity limits, and observed customer demand behavior under extreme cold conditions.

b) Conduct empirical analyses of gas demand during very low temperature events to determine whether gas demand growth begins to flatten as heating systems approach practical capacity constraints, rather than assuming continued proportional growth at increasingly extreme temperatures. Where feasible, this analysis should distinguish between space-heating and non-space-heating loads.

c) Develop a more transparent and consistent framework for design day planning assumptions across Maryland's gas companies. This framework should clearly justify not only individual planning assumptions—such as design temperatures, return periods, confidence intervals, and reserve margins—but also how these assumptions are combined to produce overall design day demand forecasts. The framework should prevent unreasonable compounding of conservatism and ensure that resulting design day assumptions remain consistent with HVAC sizing practices, practical system constraints, and observed demand behavior.

Overall, these changes would better align design day forecasting with physical system realities, prudent risk management, and the goal of avoiding unnecessary investment in gas infrastructure or peak gas supply resources.

IV. Recommendations for Future Planning Practices

Q. Please summarize your recommendations.

A. My recommendations on the gas companies' load forecasting methodologies include the following:

(1) Impacts of Emerging Market Trends on Demand Forecasting

The Commission should require the gas companies to:

a) Supplement traditional regression-based forecasting methods—which rely on historical data to quantify how gas usage varies with key drivers such as weather, economic activity, and customer growth—with forward-looking market analyses that explicitly incorporate recent and observable trends in electrification, heat pump adoption, fuel-switching behavior, and customer technology preferences.
b) Use available market data—including heating equipment installation trends, replacement choices, and fuel selection patterns—to better estimate structural shifts in customer counts, usage per customer, and long-term gas demand trajectories.

(2) Impacts of Policy on Demand Forecasting

The Commission should require the gas companies to:

a) Adopt scenario-based demand forecasting practices that explicitly model the potential impacts of current, proposed, and forthcoming State and local policies

across a range of plausible policy implementation and market response pathways.

b) Develop business-as-usual, policy-aligned, and accelerated transition scenarios and evaluate impacts on gas customer counts, usage per customer, design day demand, capital investment needs, and non-pipeline alternative opportunities under each pathway.

c) Integrate these scenario results directly into infrastructure planning, capital investment decisions, and long-term gas system planning to evaluate how different demand trajectories affect infrastructure needs, overinvestment risk, stranded asset exposure, and customer rates and bills.

(3) Design Day Demand Forecasting

The Commission should require the gas companies to:

a) Re-evaluate design day assumptions to determine whether current methodologies materially exceed realistic heating requirements when compared with HVAC sizing practices, practical heating system capacity constraints, and observed demand behavior during extreme cold events.

b) Conduct empirical analyses of actual gas demand during extreme weather events to determine whether aggregate gas demand growth materially diminishes as heating systems approach practical operating limits, rather than assuming continued proportional growth under increasingly extreme conditions.

c) Participate in and support a Commission-directed process with opportunity for public input to develop a more transparent and consistent framework for design day planning assumptions, including clear justification for design temperatures, return periods, reserve margins, confidence intervals, and similar planning assumptions—both individually and in combination—to ensure that their

cumulative effect does not produce unreasonable or unsupported levels of conservatism.

Collectively, these reforms would improve gas utilities' forecasting accuracy, better align gas planning with Maryland's climate goals and customer affordability interests, reduce the risk of unnecessary infrastructure investment and stranded assets, and support prudent long-term decision-making.

Q. Does this conclude your testimony?

A. Yes.