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

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.

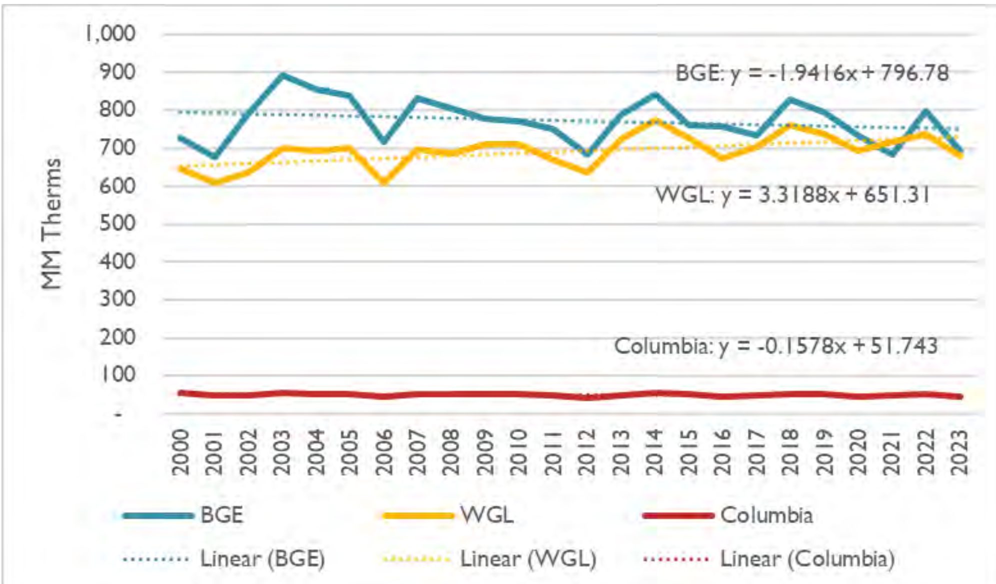
Q. What are the implications of relying on historical trends for forecasting?

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?

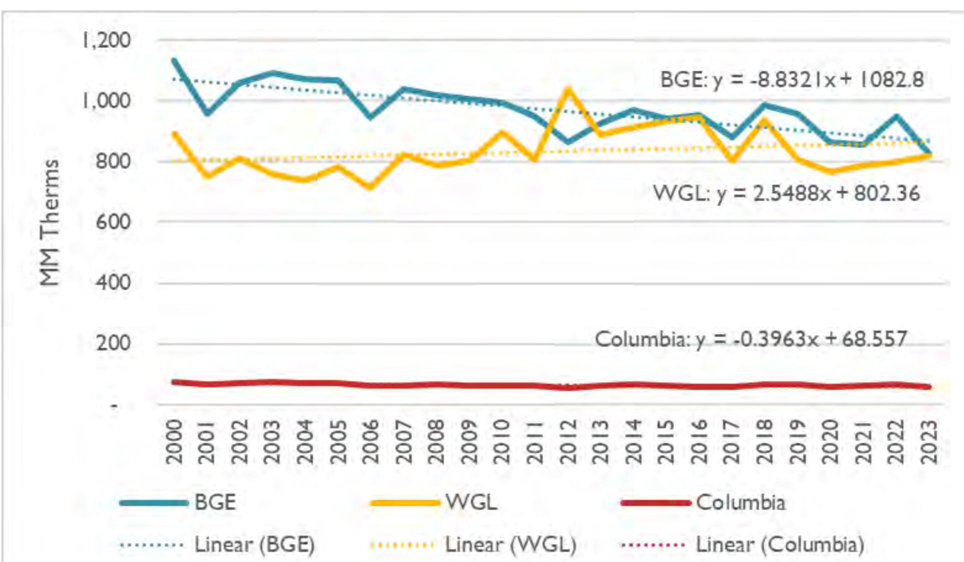
A. If historical gas consumption trends alone were extended forward, without considering other drivers or structural changes, future gas demand would appear broadly similar to past patterns and would include modest declines in usage per customer associated with historical energy efficiency improvements 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

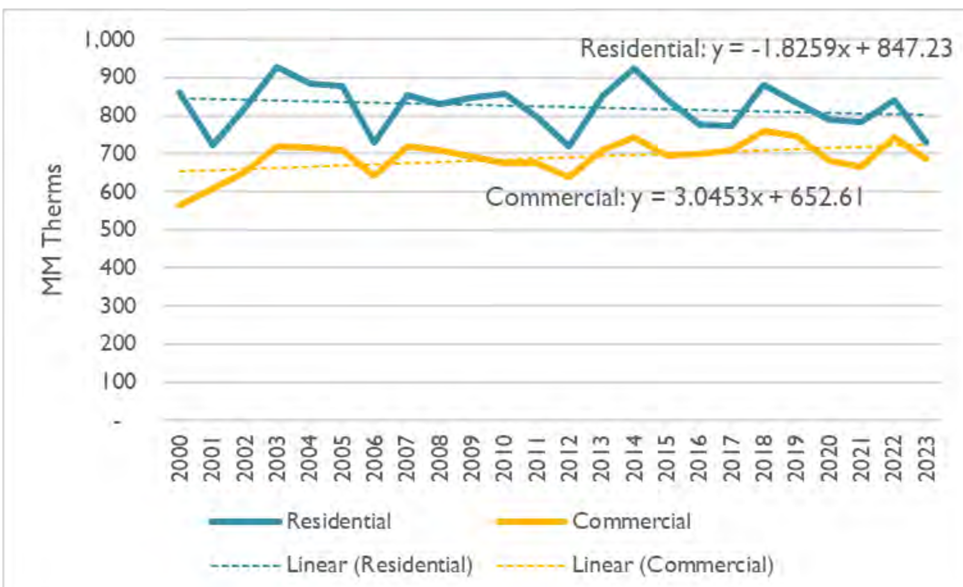


Source: EIA-176 database. Available at: https://www.eia.gov/naturalgas/ngqs/#?year1=2021&year2=2024&company=Name.

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.

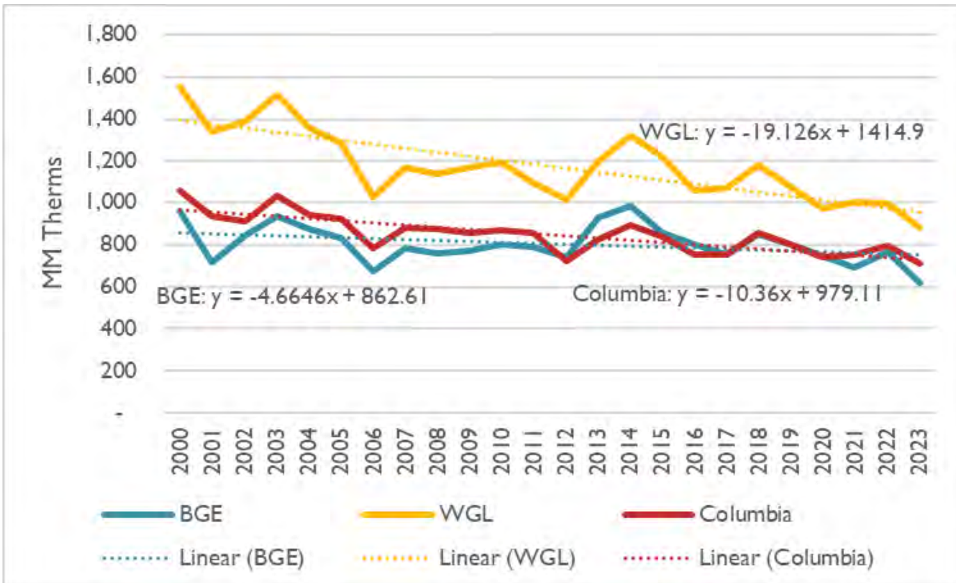
Figure 3. Residential and Commercial Total Consumption Trends for BGE, WGL, And Columbia



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

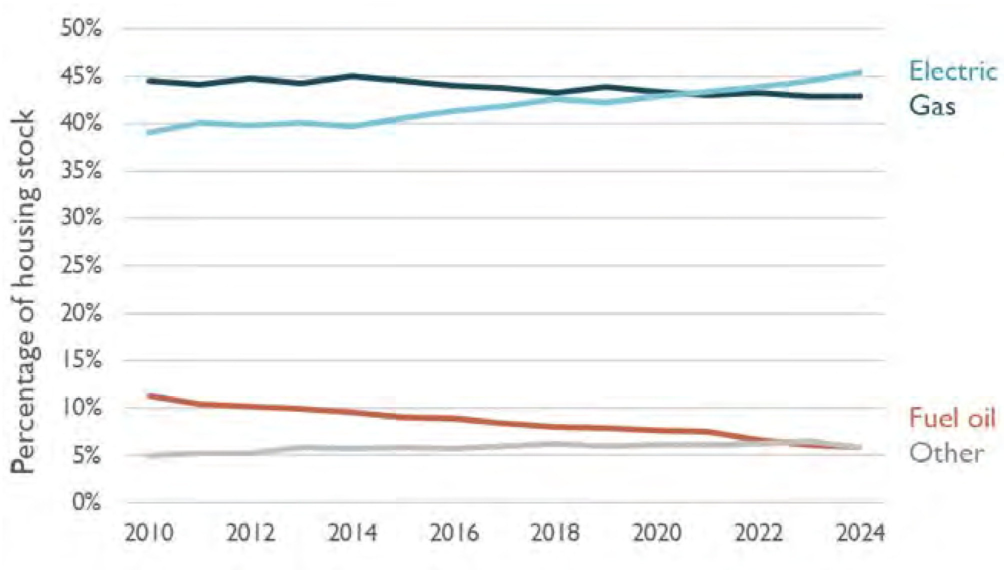
	2015	2024	Annual growth rate
Utility gas	968,764	1,029,007	0.61%
Electricity	883,862	1,089,518	2.11%
Fuel oil	197,050	140,292	-3.34%
Other*	128,258	142,577	1.06%
Total	2,177,934	2,401,394	

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]

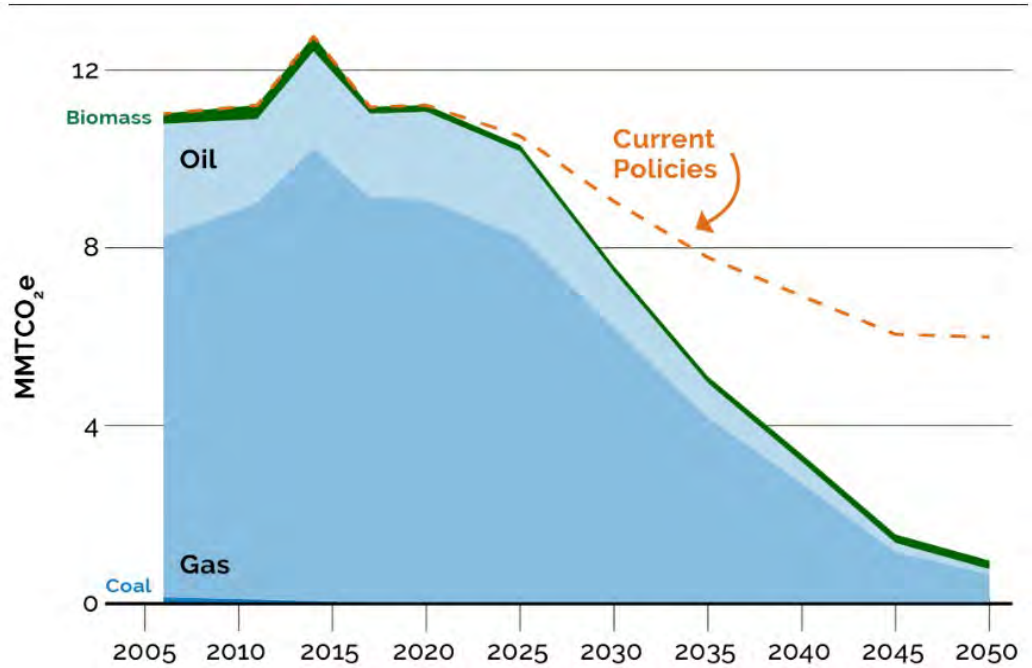
Q. Has any Maryland state agency evaluated the potential greenhouse gas reductions associated with current and proposed building-sector climate policies?

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]

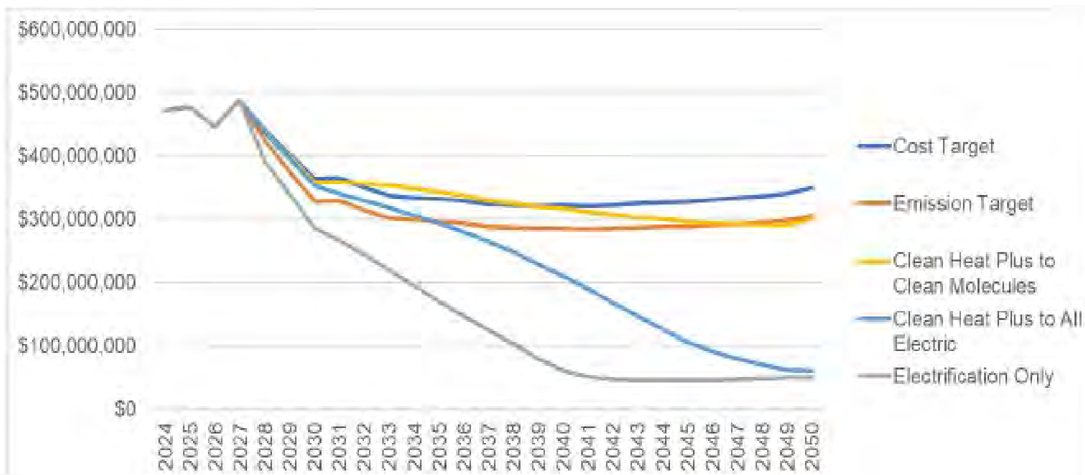
---

[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

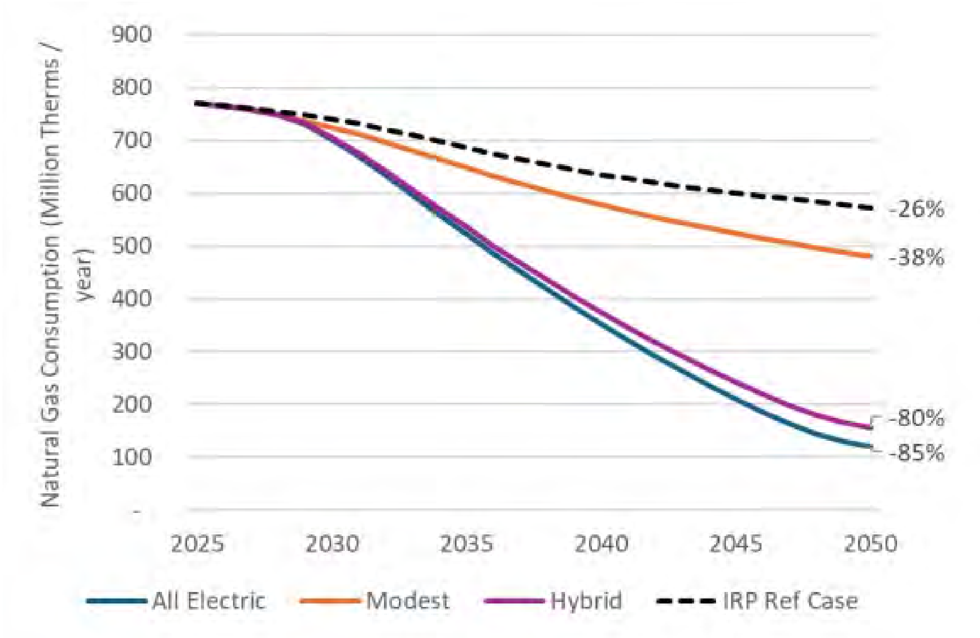


Source: Ihle, Jack W. 2023. *Supplemental Direct Testimony of Jack W. Ihle*, Hearing Exhibit 110, Colorado Public Utilities Commission, Proceeding No. 23A-0392EG, Figure JWI-SD-3.

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.

Kenji Takahashi, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7038
ktakahashi@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc, Cambridge, MA. *Principal Associate,* Apr. 2023–Present*; Senior Associate,* 2015–Apr. 2023*; Associate*, 2004–2015.

Analyzes technologies, policies, and regulations associated with supply- and demand-side energy resources. Assesses the performance, costs, and potential of energy efficiency measures, renewable energy resources, and building decarbonization and electrification measures. Examines economic and environmental implications of clean energy policies and programs associated with energy efficiency, demand response, distributed generation, and renewable energy. Analyzes ratemaking issues such as standby rates and time of use rates for distributed generation, and decoupling rate mechanisms for energy efficiency measures. Investigates electricity and natural gas market price trends and fluctuations. Prepares expert testimony and reports for regulatory proceedings.

Center for Energy and Environmental Policy, University of Delaware, Newark, DE. *Research Associate*, 2002–2004.

Researched the market potential of distributed resources under different electric distribution rate designs (report prepared for Conectiv Power Delivery Company). Investigated the potential of the Clean Development Mechanisms (CDM) in Asian developing countries and the Japanese government's policy for CDM. Contributed to a market penetration study for photovoltaic technologies in comparison with the predicted oil production from the oil reservoirs in the Arctic National Wildlife Refuge (report prepared for Astropower, Inc.). Analyzed the installation of PV and generation-set options for the Assateague Beach Coastal Guard Station at the Assateague Island National Seashore in Maryland (report prepared for the U.S. National Park Service).

Delaware Division of Public Advocate, Wilmington, DE. *Research Intern*, 2003.

Researched and wrote reports on states' policies regarding (1) energy efficiency/load management programs in order to identify cost-effective programs for implementation in Delaware; (2) electric standard offer service/default service (rate designs) for those who do not choose alternative suppliers under the deregulation process; (3) electric universal service and system benefit charges for protecting consumers from risks associated with electricity restructuring; and (4) Contributions and Advances-in-Aid-of-Construction for water supply extensions.

Resources for the Future, Washington DC. *Research Intern*, 2002.

Investigated current and planned wind power capacity for the United States. Analyzed the EPA and EIA market models to estimate technical and economic potential of wind power in the United States.

Researched the status of renewable energy supply in Japan's electricity sector for the Economic and Social Research Institute, Cabinet Office, Government of Japan.

Citizens' Alliance for Saving the Atmosphere and the Earth (CASA), Osaka, Japan. *Volunteer and Researcher*, 1999–2001.

Worked as a newsletter writer, editor, and event organizer. Wrote a report on the first experimental biomass energy facility in Japan and the photovoltaic system at Yagi Junior High School in Kyoto, Japan. Participated in a research project to investigate renewable energy potential and policies in Japan. Wrote a report on problems of nuclear power plants affecting communities in Fukui prefecture, Japan.

EDUCATION

University of Delaware, **Center for Energy and Environmental Policy, Joseph R. Biden, Jr School of Public Policy and Administration**, Newark, DE
Master of Arts in Urban Affairs and Public Policy with a focus on Energy and Environmental Policy, 2003. Master's thesis: *Policies to Support Distributed Resources under Different Electricity Restructuring Models*. Courses in energy economics, energy and environmental policy, electricity policy and planning, political economy of environment, solar electric technology, cost-benefit and decision-making analyses, and geographic information system.

Kansai University, Osaka, Japan
Bachelor of Arts in Law with a concentration in Public Administration, 2000.

ADDITIONAL EDUCATION

Massachusetts Institute of Technology, Cambridge, MA
Professional Education Course: Sustainable Infrastructure Systems: Planning and Operations, 2022.

AWARDS AND SCHOLARSHIPS

- Director's Citation, Joseph R. Biden, Jr School of Public Policy and Administration, University of Delaware. May 2003.
- NEC scholarship for an environmental education leader-training program funded by one of the leading Japanese computer companies, NEC. Nov. 2000.

ADDITIONAL SKILLS

Software: MS Office, Minitab, Analytica, IMPLAN, AVoided Emissions and geneRation Tool (AVERT), CO–Benefits Risk Assessment (COBRA), RETScreen, BEopt™, REM/Rate™
Language: Japanese, Spanish, and Cantonese

TESTIMONY

Colorado Public Utilities Commission (No. 25A-0044EG): Direct Testimony of Kenji Takahashi in the matter of the application of Public Service Company of Colorado for approval of the Mountain Energy Project and Associated Certificate of Public Convenience and Necessity (CPCN) for Supplemental Supply.

Maryland Public Service Commission (Case No.9702): Direct Testimony of Kenji Takahashi in the matter of the application of Potomac Electric Power Company for an Electric Multi-Year Plan for the distribution of electric energy. December 15, 2023.

New Mexico Public Regulation Commission (Case No. 22-00138-UT): Direct Testimony regarding Public Service Company of New Mexico's application for approve of its 2024 Electric Energy Efficiency Program Plan. On behalf of the Office of the Attorney General, September 18, 2023.

Maryland Public Service Commission (Case No.9692): Direct Testimony of Kenji Takahashi in the matter of the application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of the Office of People's Counsel. June 20, 2023.

Maryland Public Service Commission (Case No.9692): Surrebuttal Testimony of Kenji Takahashi in the matter of the application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of the Office of People's Counsel. August 25, 2023.

Maryland Public Service Commission (Case No.9702): Surrebuttal Testimony of Kenji Takahashi in the matter of the application of Potomac Electric Power Company for an Electric Multi-Year Plan for the distribution of electric energy. February 23, 2023.

New Mexico Public Regulation Commission (Case No. 22-00232-UT): Direct Testimony regarding New Mexico Gas Company's application for approve of its 23023-2025 Energy Efficiency Program. On behalf of the Office of the Attorney General, November 2022.

Nova Scotia Utility and Review Board (M10473): Evidence of Alice Napoleon and Kenji Takahashi regarding EfficiencyOne's 2023-2025 DSM Resource Plan, with a focus on the Settlement Plan. On behalf of Counsel to Nova Scotia Utility and Review Board, May 2022.

Pennsylvania Public Utility Commission (Docket No. M-2020-3020824): Revised Direct Testimony of Alice Napoleon and Kenji Takahashi regarding PPL Electric Utilities' proposed Act 129 Phase IV Energy Efficiency and Conservation. On behalf of the Natural Resources Defense Council. January 19, 2021.

New York Public Service Commission (Cases 20-E-0380 and 20-G-0381): Direct testimony of Alice Napoleon and Kenji Takahashi regarding proposed earnings adjustment mechanisms in a proceeding on Rates, Charges, Rules, and Regulations related to Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service and National Grid for Gas Service. On behalf of the Natural Resources Defense Council. November 25, 2020.

Massachusetts Department of Public Utilities (D.P.U. 16-103): Direct testimony regarding Berkshire Gas Company's Forecast and Supply Plan. On behalf of the Town of Montague. March 8, 2017.

Ontario Energy Board (EB-2015-0049 and EB-2015-0029): Testimony on *Ontario Gas Demand-Side Management 2016-2020 Plan Review,* expert report on Enbridge Gas Distribution Inc.'s and Union Gas Limited's proposed gas DSM plans. On behalf of the Ontario Energy Board. September 2-3, 2015.

New Jersey Board of Public Utilities (Docket No. EO14080897): Direct testimony regarding Public Service Electric and Gas Company's petition to continue its Energy Efficiency Economic Extension program. On behalf of the New Jersey Division of Rate Counsel. November 7, 2014.

TESTIMONY ASSISTANCE

Michigan Public Service Commission (Case No. U-21806): Direct Testimony of Alice Napoleon in the matter of the Application of Consumers Energy Company for authority to increase its rates for the distribution of natural gas and for other relief. Synapse Energy Economics for Michigan Environmental Council and Sierra Club. April 23, 2025.

Public Service Commission of South Carolina (Docket No. 2016-223-E): Direct Testimony of Alice Napoleon regarding South Carolina Electric and Gas Energy Efficiency Efforts. On behalf of South Carolina Coastal Conservation League. September 1, 2016.

Maine Public Utilities Commission (Docket No. 2015-00175): Direct testimony of Tim Woolf on Efficiency Maine Trust's petition for approval of the Triennial Plan for Fiscal Years 2017-2019. On behalf of the Natural Resources Council of Maine and the Conservation Law Foundation. February 17, 2016.

Missouri Public Service Commission (File No. EO-2015-0055): Rebuttal and surrebuttal testimony of Tim Woolf on the topic of Ameren Missouri's 2016-2018 Energy Efficiency Plan. On behalf of Sierra Club. March 20, 2015 and April 27, 2015.

Florida Public Service Commission (Docket No. 130199-EI – No. 130205-EI): Testimony of Tim Woolf regarding setting goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems in Florida utilities. On behalf of Sierra Club. May 19, 2014.

Colorado Public Utilities Commission (Docket No. 13A-0686EG): Testimony of Tim Woolf regarding setting energy efficiency goals for the Public Service Company of Colorado's demand-side management plan. On behalf of Sierra Club. October 16, 2013.

Kentucky Public Service Commission (Case No. 2012-00578): Testimony of Tim Woolf regarding Kentucky Power Company's economics analysis of the proposed purchase of the Mitchell Generating Station. On behalf of Sierra Club. April 1, 2013.

State of New Jersey Board of Public Utilities (Docket No. GO11070399): Testimony of Robert Fagan regarding Elizabethtown Gas Company's Proposed Energy Efficiency Program. On behalf of New Jersey Division of the Ratepayer Advocate. December 16, 2011.

State of New Jersey Board of Public Utilities (Docket No. GR10030225): Testimony of David Nichols before the New Jersey Natural Gas Company's Proposed Energy Efficiency Program. On behalf of New Jersey Division of the Ratepayer Advocate. July 9, 2010.

Pennsylvania Public Utility Commission (Docket Nos. R-2009-2139884 and P-2009-2097639): Testimony of David Nichols regarding Philadelphia Gas Works' Proposed Energy Efficiency Plan. On behalf of Pennsylvania Office of Consumer Advocate. March 26, 2010.

Florida Public Service Commission (Docket NO. 080407-EG et al.): Testimony of William Steinhurst regarding Florida Demand Side Management Policy and Planning. On behalf of Natural Resources Defense Council (NRDC) and Southern Alliance for Clean Energy. July 6, 2009.

Iowa Utilities Board (Docket No. EEP-08-01): Testimony of Chris James regarding Interstate Power and Light Company's Proposed Energy Efficiency Program. On behalf of Community Coalition and Plains Justice. August 29, 2008.

Nova Scotia Utility and Review Board (Case No. M00208): Testimony of Bruce Biewald and David Nichols regarding Nova Scotia Power Inc's Demand Side Management Plan. Oh behalf of The Utility and Review Board Staff f. March 17, 2008.

Public Utilities Commission of Nevada (Docket No. 06-06051): Testimony of Tim Woolf regarding the review of the Nevada Power Company's Demand Side Management Plan in the 2006 Integrated Resource Plan. On behalf of Nevada Bureau of Consumer Protection. September 13, 2006.

Public Utilities Commission of California (Application A.04-06-024): Testimony of Amy Roschelle regarding the review of Pacific Gas and Electric's Application to Establish a Demonstration Climate Protection Program and Tariff Option. On behalf of The Utility Reform Network (TURN). May 5, 2006.

Public Service Commission of Nevada (Docket No. 05-10021): Testimony of Tim Woolf regarding the Sierra Pacific Power Company's Gas Demand-Side Management Plan. On behalf of Nevada Bureau of Consumer Protection. February 22, 2006.

PUBLICATIONS

Takahashi, K., E. Carlson, A. Glaser Schoff, A. Fuzaylov, S. Shenstone-Harris, A. Hopkins, P. Knight. 2026. *Regional Electric Peak Load Forecasts for Maine: Implications of Electrification and ISO-NE CELT Forecasts*. Synapse Energy Economics for the Maine Office of the Public Advocate.

Takahashi, K., A. Hopkins, P. Eash-Gates, E. Carlson, K. Schultz, E. Ashley. 2025. *Strategic Roadmap for Building Decarbonization - Policy, Regulatory, Workforce, and Equity Strategies for a Cleaner, Greener New Jersey.* Synapse Energy Economics and New Jersey agencies for the Governor's Office of Climate Action and the Green Economy.

Shenstone-Harris, S., M. Whited, K. Takahashi, S. Schadler, A. Fuzaylov, I. Weiss. 2025. *How Will Future Electric Vehicle Adoption and Building Electrification Affect Electric Rates?* New Jersey Factsheet. Synapse Energy Economics for Natural Resources Defense Council.

Shenstone-Harris, S., M. Whited, K. Takahashi, S. Schadler, A. Fuzaylov, I. Weiss. 2025. *How Will Future Electric Vehicle Adoption and Building Electrification Affect Electric Rates?* New Mexico Factsheet. Synapse Energy Economics for Natural Resources Defense Council.

Takahashi, K., A. Glaser Schoff, B. Havumaki. 2024. *Evidence Regarding Nova Scotia Power's 2024 Load Forecast*. Synapse Energy Economics for Nova Scotia Utility and Review Board.

Napoleon, A., T. Nguyen, S. Schadler, S. deLeon, K. Takahashi. 2024. *Comments of Environmental Defense Fund, Natural Resources Defense Council, Sierra Club, Earthjustice, and Alliance for a Green Economy on Non-Pipes Alternative Framework Questions.* Synapse Energy Economics for Natural Resources Defense Council.

Takahashi, K., C. Lane, M. Whited, S. Schadler, T. Gyalmo, A. Zeng, A. S. Hopkins. 2024. *Charging Minnesota's Electric Vehicles; Strategies that Work for the Electric Grid and Consumers.* Synapse Energy Economics for Minnesota Department of Commerce, Division of Energy Resources.

Kallay, J., A. Napoleon, E. Ashley, K. Takahashi, T. Woolf. 2024. *Review of New Brunswick Power's 2024/25 to 2026/27 DSM Program Initiatives Update.* Synapse Energy Economics for the New Brunswick Energy and Utilities Board Staff.

Biewald, B., D. Glick, S. Kwok, K. Takahashi, J. Carvallo, L. Schwartz. 2024. *Best Practices in Integrated Resource Planning: A guide for planners developing the electricity resource mix of the future.* Synapse Energy Economics and Lawrence Berkeley National Laboratory for The Energy Foundation.

Takahashi, K., A. S. Hopkins, E. Carlson, S. Schadler, S. Chavin. 2024. *Memo: Assessment of Electric Grid Headroom for Accommodating Building Electrification (Revised July 2024).* Synapse Energy Economics to New Yorkers for Clean Power.

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.* Synapse Energy Economics for Clean Heat Minnesota.

Takahashi, K. 2024. *Memo: OPC's Comments to EAG Work Group in response to GTI Energy's EHP vs GHP Methodology for Washington Gas Maryland Gas Heat Pump Pilot.* Synapse Energy Economics for Maryland Office of the People's Counsel.

District of Columbia Department of Energy and Environment Energy Administration. 2023. *The Strategic Electrification Roadmap for Buildings and Transportation in the District of Columbia*. Prepared for the Office of Energy Efficiency and Renewable Energy U.S. Department of Energy with Synapse Energy Economics as Technical Contributor.

Takahashi, K., E. Carlson, P. Eash-Gates, K. Schultz, P. Rhodes, A. S. Hopkins. 2023. *Building Decarbonization Strategies for the Southwest - Analysis of the costs and emissions reduction potential of space and water heating decarbonization*. Synapse Energy Economics for Western Resource Advocates.

Takahashi, K. 2023. *Memo: Comment on WGL's Response to OPC's February Comments on WGL's Gas Heat Pump Assessment.* Synapse Energy Economics for Maryland Office of the People's Counsel.

Hopkins, A. S., A. Napoleon, J. Litynski, K. Takahashi, J. Frost, S. Kwok. 2022. *Climate Policy for Maryland's Gas Utilities: Financial Implications*. Synapse Energy Economics for Maryland Office of the People's Counsel.

Kwok, S., K. Takahashi, J. Litynski, A. S. Hopkins. 2022. Memo: Massachusetts DPU Docket-2080: Proposed "Common Regulatory Framework." Synapse Energy Economics for Conservation Law Foundation.

Hopkins, A. S. S. Kwok, J. Litynski, A. Napoleon, K. Takahashi. 2022. Memo: Evaluation of Draft Consultant Reports in Massachusetts DPU Docket 20-80. Synapse Energy Economics for Conservation Law Foundation.

Takahashi, K., S. Kwok, J. Tabernero, F. Frost. 2022. *Toward Net Zero Emissions from Oregon Buildings*. Synapse Energy Economics for Sierra Club.

Takahashi, K., T. Woolf, B. Havumaki, D. White, D. Goldberg, S. Kwok, A. Takasugi. 2022. *Missed Opportunities - The Impacts of Recent Policies on Energy Efficiency Programs in Midwestern States.* Presented at the 2022 ACEEE Summer Study of Energy Efficiency in Buildings.

Hopkins A. S., P. Eash-Gates, J. Frost, S. Kwok, J. Litynski, K. Takahashi. "Decarbonization of Buildings." In *San Diego Regional Decarbonization Framework*, edited by SDG Policy Initiative, School of Global Policy and Strategy, University of California San Diego. March 2022.

Douglas, A., J. Kallay, S. Singh Walker, A. Hopkins, A. Napoleon, & K. Takahashi. 2022. Future Proofing the Texas Grid with Distributed Energy Resources. Synapse Energy Economics for Texas Advanced Energy Business Alliance.

Frost, J. S. Kwok, K. Takahashi, A.S. Hopkins, A. Napoleon. 2021. *New York Heat Pump Trajectory Analysis*. Synapse Energy Economics for NRDC.

Hopkins, A. S., A. Napoleon, K. Takahashi. 2021. *A Framework for Long-Term Gas Utility Planning in Colorado*. Synapse Energy Economics for the Colorado Energy Office.

Hopkins, A. S., A. Napoleon, T. Woolf, K. Takahashi. 2021. *Long-Term Planning to Support the Transition of New York's Gas Utility Industry*. Synapse Energy Economics for Natural Resources Defense Council.

Kallay, J., A. Napoleon, K. Takahashi, E. Sinclair, T. Woolf. 2021. *Opportunities for Evergy Kansas to Address Energy Equity Within its Integrated Resource Plan and Other Planning Processes*. Synapse Energy Economics for Union of Concerned Scientists.

Takahashi, K., T. Woolf, B. Havumaki, D. White, D. Goldberg, S. Kwok, A. Takasugi. 2021. *Missed Opportunities: The Impacts of Recent Policies on Energy Efficiency Programs in Midwestern States.* Synapse Energy Economics for the Midwest Energy Efficiency Alliance.

Takahashi, K., E. Sinclair, A. Napoleon, A.S. Hopkins, D. Goldberg. 2021. *Evaluation of EnergyWise Low-Income Energy Efficiency Program in Mississippi – Program Performance, Design, and Implications for Low-Income Efficiency Programs*. Synapse Energy Economics for Sierra Club and Gulf Coast Community Foundation.

Wilson, R., I. Addleton, K. Takahashi, J. Litynski. 2021. *Clean, Affordable, and Reliable – A Plan for Duke Energy's Future in the Carolinas*. Synapse Energy Economics for North Carolina Sustainable Energy Association, Carolinas Clean Energy Business Alliance, Southern Alliance for Clean Energy, Natural Resources Defense Council and the Sierra Club.

Eash-Gates, P., K. Takahashi, D. Goldberg, A.S. Hopkins, S. Kwok. 2021. *Boston Building Emissions Performance Standard: Technical Methods Overview.* Synapse Energy Economics for the City of Boston.

Shipley, J., Hopkins, A., Takahashi, K., & Farnsworth, D. 2021. *Renovating regulation to electrify buildings: A guide for the handy regulator*. Regulatory Assistance Project.

Goldberg, D., J. Frost, D. Hurley, K. Takahashi. 2020. *New England Electrification Load Forecast*. Synapse Energy Economics for E4TheFuture.

Camacho, J., K. Takahashi, A. S. Hopkins, D. White. 2020. *Assessment of Proposed Energize Eastside Project*. Synapse Energy Economics and MaxETA Energy for the City of Newcastle, WA.

Lane, C., K. Takahashi. 2020. *Rate and Bill Impact Analysis of Rhode Island Natural Gas Energy Efficiency Programs*. Synapse Energy Economics for National Grid.

Takahashi, K., A. S. Hopkins, D. White, S. Kwok, N. Garner. 2020. *Assessment of National Grid's Long-Term Capacity Report – Natural gas capacity needs and alternatives*. Synapse Energy Economics for the Eastern Environmental Law Center.

Takahashi, K., J. Frost, D. Goldberg, A. S. Hopkins, K. Nishio, K. Nakano. 2020. *Survey of U.S. State and Local Building Decarbonization Policies and Programs.* Presented at the 2020 ACEEE Summer Study of Energy Efficiency in Buildings.

Hopkins, A. S., A. Napoleon, K. Takahashi. 2020. *Gas Regulation for a Decarbonized New York: Recommendations for Updating New York Gas Utility Regulation.* Synapse Energy Economics for Natural Resources Defense Council.

Takahashi, K., A. Napoleon. 2020. *Synapse Comments on EfficiencyOne Performance Alignment Study - M09096.* Questions and comments regarding the EfficiencyOne Performance Alignment Study filed on April 21, 2020. Synapse Energy Economics for the Nova Scotia Utility and Review Board.

Napoleon, A., J. Kallay, K. Takahashi. 2020. *Utility Energy Efficiency and Building Electrification Portfolios Through 2025: A Brief on the New York Public Service Commission's Recent Order.* Synapse Energy Economics for the Natural Resources Defense Council.

Hopkins, A. S., K. Takahashi, Nadel, S. 2020. "Keep warm and carry on: Electrification and efficiency meet the 'polar vortex'." Proceedings of the 2020 ACEEE Summer Study of Energy Efficiency in Buildings.

Kallay, J., A. Hopkins, J. Frost, A. Napoleon, K. Takahashi, J. Slason, G. Freeman, D. Grover, B. Swanson. 2019. *Net Zero Energy Roadmap for the City of Burlington, Vermont.* Synapse Energy Economics and Resource Systems Group for Burlington Electric Department.

White, D., K. Takahashi, M. Whited, S. Kwok, D. Bhandari. 2019. *Memphis and Tennessee Valley Authority: Risk Analysis of Future TVA Rates for Memphis.* Synapse Energy Economics for Friends of the Earth.

Napoleon, A., T. Woolf, K. Takahashi, J. Kallay, B. Havumaki. 2019. *Comments in the New York Public Service Commission Case 18-M-0084: In the Matter of a Comprehensive Energy Efficiency Initiative.* Comments related to NY Utilities report regarding energy efficiency budgets and targets, collaboration, heat pump technology, and low- and moderate-income customers and requests for approval. Synapse Energy Economics on behalf of Natural Resources Defense Council.

Havumaki, B., J. Kallay, K. Takahashi, T. Woolf. 2019. *All-Electric Solid Oxide Fuel Cells as an Energy Efficiency Measure.* Synapse Energy Economics for Bloom Energy.

Takahashi, K., B. Havumaki, J. Kallay, T. Woolf. 2019. *Bloom Fuel Cells: A Cost-Effectiveness Brief.* Synapse Energy Economics for Bloom Energy.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. (2019). *Phase 2 Report on Muskrat Falls Project Rate Mitigation: Newfoundland and Labrador Hydro Rate Mitigation Approaches: Options for Cost Savings and Revenue Opportunities through Export Market Sales, Energy Efficiency, In-Province Electrification and Rate Design Approaches After In-Service of the Muskrat Falls Project*. Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Napoleon, A., D. Goldberg, K. Takahashi, T. Woolf. 2019. *An Assessment of Prince Edward Island Energy Corporations' 2018 - 2021 Energy Efficiency and Conservation Plan.* Synapse Energy Economics for Carr, Stevenson and MacKay as Counsel to the Island Regulatory and Appeals Commission.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Hopkins, A. S., K. Takahashi, L. David. 2018. *Challenges and Opportunities for Deep Decarbonization through Strategic Electrification under the Utility Regulatory Structures of the Northeast*. Proceedings of the 2018 ACEEE Summer Study on Energy Efficiency in Buildings, August 12, 2018.

Hall, J., J. Kallay, A. Napoleon, K. Takahashi, M. Whited. *Locational and Temporal Value of Energy Efficiency and other DERs to Transmission and Distribution Systems*. Proceedings of the 2018 ACEEE Summer Study on Energy Efficiency in Buildings, August 12, 2018.

White, D., K. Takahashi, A. Napoleon, T. Woolf. 2018. *Value of Energy Efficiency in New York: Assessment of the Range of Benefits of Energy Efficiency Programs*. Synapse Energy Economics for Natural Resources Defense Council.

Woolf, T., A. Hopkins, M. Whited, K. Takahashi, A. Napoleon. 2018. *Review of New Brunswick Power's 2018/2019 Rate Case Application.* In the Matter of the New Brunswick Power Corporation and Section 103(1) of the Electricity Act Matter No. 375. Synapse Energy Economics for the New Brunswick Energy and Utilities Board Staff.

Hopkins, A. S., K. Takahashi. 2017. *Alternatives to Building a New Mt. Vernon Substation in Washington, DC*. Synapse Energy Economics for the District of Columbia Department of Energy and Environment.

Hopkins, A.S., A. Horowitz, P. Knight, K. Takahashi, T. Comings, P. Kreycik, N. Veilleux, J. Koo. 2017. *Northeast Regional Assessment of Strategic Electrification.* Synapse Energy Economics and Meister Consulting Group for the Northeast Energy Efficiency Partnerships.

Takahashi, K., A. Allison, D. White. 2017. *Renewable Heating and Cooling Policy Framework: Options to Advance Industry Growth and Markets in New York*. Prepared for the New York State Energy Research and Development Authority.

Sierra Club. 2017. *Sierra Club Comments on Portland General Electric Company 2016 Integrated Resource Plan*. Submitted to the Public Utility Commission of Oregon, January 24, 2017.

Cook, R., J. Koo, N. Veilleux, K. Takahashi, E. Malone, T. Comings, A. Allison, F. Barclay, L. Beer. 2017. *Rhode Island Renewable Thermal Market Development Strategy*. Meister Consultants Group and Synapse Energy Economics for Rhode Island Office of Energy Resources.

Takahashi, K, T. Woolf, J. Kallay, E. Malone, A. Napoleon, M. Whited. 2016. *Starting Energy Efficiency Off on the Right Foot–Regulatory Policies to Support Successful Program Planning and Design.* Synapse Energy Economics for Prince Edward Island Regulatory & Appeals Commission.

Woolf, T., M. Whited, P. Knight, T. Vitolo, K. Takahashi. 2016. *Show Me the Numbers: A Framework for Balanced Distributed Solar Policies*. Synapse Energy Economics for Consumers Union.

Fisher, J., P. Luckow, A. Horowitz, T. Comings, A. Allison, E.A. Stanton, S. Jackson, K. Takahashi. 2016. *Michigan Compliance Assessment for the Clean Power Plan: MPSC/MDEQ EPA 111(d) Impact Analysis*. Prepared for Michigan Public Service Commission, Michigan Department of Environmental Quality, and Michigan Agency for Energy.

Woolf, T., A. Napoleon, P. Luckow, W. Ong, K. Takahashi. 2016. *Aiming Higher: Realizing the Full Potential of Cost-Effective Energy Efficiency in New York.* Synapse Energy Economics for Natural Resources Defense Council, E4TheFuture, CLEAResult, Lime Energy, Association for Energy Affordability, and Alliance for Clean Energy New York.

Napoleon, A., K. Takahashi, J. Kallay, T. Woolf. 2016. "Evaluation, Measurement, and Verification in Virginia." Synapse Energy Economics for Clean Energy Solutions Inc., Virginia Energy Efficiency Council, and Virginia Department of Mines, Minerals and Energy.

Stanton, E. A., P. Knight, A. Allison, T. Comings, A. Horowitz, W. Ong, N. R. Santen, K. Takahashi. 2016. *The RGGI Opportunity 2.0: RGGI as the Electric Sector Compliance Tool to Achieve 2030 State Climate Targets.* Synapse Energy Economics for Sierra Club, Pace Energy and Climate Center, and Chesapeake Climate Action Network.

Stanton, E. A., P. Knight, A. Allison, T. Comings, A. Horowitz, W. Ong, N. R. Santen, K. Takahashi. 2016. *The RGGI Opportunity: RGGI as the Electric Sector Compliance Tool to Achieve 2030 State Climate Targets.* Synapse Energy Economics for Sierra Club, Pace Energy and Climate Center, and Chesapeake Climate Action Network.

Kallay, J., K. Takahashi, A. Napoleon, T. Woolf. 2015. *Fair, Abundant, and Low-Cost: A Handbook for Using Energy Efficiency in Clean Power Plan Compliance.* Synapse Energy Economics for the Energy Foundation.

Woolf, T., K. Takahashi, E. Malone, A. Napoleon, J. Kallay. 2015. *Ontario Gas Demand-Side Management 2016-2020 Plan Review.* Synapse Energy Economics for the Ontario Energy Board.

Biewald, B., J. Daniel, J. Fisher, P. Luckow, A. Napoleon, N. R. Santen, K. Takahashi. 2015. *Air Emissions Displacement by Energy Efficiency and Renewable Energy.* Synapse Energy Economics.

Takahashi, K. 2015. "Boost Appliance Efficiency Standards." Ed. John Shenot. In *Implementing EPA's Clean Power Plan: A Menu of Options.* National Association of Clean Air Agencies.

Takahashi, K., A. Napoleon. 2015. "Pursue Behavioral Efficiency Programs." Ed. John Shenot. In *Implementing EPA's Clean Power Plan: A Menu of Options.* National Associate of Clean Air Agencies.

Takahashi, K., J. Fisher, T. Vitolo, N. R. Santen. 2015. *Review of TVA's Draft 2015 Integrated Resource Plan*. Synapse Energy Economics for Sierra Club.

Comings, T., S. Jackson, K. Takahashi. 2015. *Comments on Indianapolis Power & Light Company's 2014 Integrated Resource Plan*. Synapse Energy Economics for the Sierra Club.

Stanton, E. A., P. Knight, J. Daniel, B. Fagan, D. Hurley, J. Kallay, E. Karaca, G. Keith, E. Malone, W. Ong, P. Peterson, L. Silvestrini, K. Takahashi, R. Wilson. 2015. *Massachusetts Low Gas Demand Analysis: Final Report.* Synapse Energy Economics for the Massachusetts Department of Energy Resources.

Fields, S., E. A. Stanton, P. Knight, B. Biewald, J. Daniel, S. Jackson, E. Karaca, J. Rosenkranz, K. Takahashi. 2014. *Calculating Alabama's 111(d) Target*. Synapse Energy Economics for the Southern Environmental Law Center.

Fields, S., E. A. Stanton, P. Knight, B. Biewald, J. Daniel, S. Jackson, E. Karaca, J. Rosenkranz, K. Takahashi. 2014. *Calculating Georgia's 111(d) Target*. Synapse Energy Economics for the Southern Environmental Law Center.

Fields, S., E. A. Stanton, P. Knight, B. Biewald, J. Daniel, S. Jackson, E. Karaca, J. Rosenkranz, K. Takahashi. 2014. *Alternate Scenarios for 111(d) Implementation in North Carolina*. Synapse Energy Economics for the Southern Environmental Law Center.

Stanton, E. A., P. Knight, J. Daniel, B. Fagan, D. Hurley, J. Kallay, G. Keith, E. Malone, P. Peterson, L. Silverstrini, K. Takahashi. 2014. *Feasibility Study for Low Gas Demand Analysis.* Synapse Energy Economics for the Massachusetts Department of Energy Resources.

Takahashi, K., T. Comings, A. Napoleon. 2014. *Maximizing Public Benefit through Energy Efficiency Investments.* Synapse Energy Economics for Sierra Club.

Vitolo, T., J. Fisher, K. Takahashi. 2014. *TVA's Use of Dispatchability Metrics in Its Scorecard.* Synapse Energy Economics for Sierra Club.

Comings, T., S. Fields, K. Takahashi, G. Keith. 2014. *Employment Effects of Clean Energy Investments in Montana.* Synapse Energy Economics for Montana Environmental Information Center and Sierra Club.

Keith, G., S. Jackson, J. Daniel, K. Takahashi. 2014. *Idaho's Electricity Sources: Current Sources and Future Potential.* Synapse Energy Economics for the Idaho Conservation League.

Malone, E. T. Woolf, K. Takahashi, S. Fields. 2013. "Appendix D: Energy Efficiency Cost-Effectiveness Tests." *Readying Michigan to Make Good Energy Decisions: Energy Efficiency*. Synapse Energy Economics for the Council of Michigan Foundations.

Takahashi, K. et al. 2013. *Economic and Environmental Analysis of Residential Heating and Cooling Systems: A Study of Heat Pump Performance in U.S. Cities*. Proceeding of the 7th International Conference on Energy Efficiency in Domestic Appliances and Lighting (EEDAL'13), September 12, 2013.

Comings, T., K. Takahashi, G. Keith. 2013. *Employment Effects of Investing in Select Electricity Resources in Washington State.* Synapse Energy Economics for Sierra Club.

Woolf, T., E. Malone, J. Kallay, K. Takahashi. 2013. *Energy Efficiency Cost-Effectiveness Screening in the Northeast and Mid-Atlantic States.* Synapse Energy Economics for Northeast Energy Efficiency Partnerships, Inc. (NEEP).

Stanton, E. A., T. Comings, K. Takahashi, P. Knight, T. Vitolo, E. Hausman. 2013. *Economic Impacts of the NRDC Carbon Standard.* Synapse Energy Economics for the Natural Resources Defense Council (NRDC).

Woolf, T., W. Steinhurst, E. Malone, K. Takahashi. 2012. *Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs.* Synapse Energy Economics for Regulatory Assistance Project and Vermont Housing Conservation Board.

Woolf, T., M. Whited, T. Vitolo, K. Takahashi, D. White. 2012. *Indian Point Energy Center Replacement Analysis: A Plan for Replacing the Nuclear Plant with Clean, Sustainable, Energy Resources.* Synapse Energy Economics for National Resources Defense Council and Riverkeeper.

Keith, G., T. Woolf, K. Takahashi. 2012. *A Clean Electricity Vision for Long Island: Supplying 100% of Long Island's Electricity Needs with Renewable Power.* Synapse Energy Economics for Renewable Energy Long Island.

Fisher, J., K. Takahashi. 2012. *TVA Coal in Crisis: Using Energy Efficiency to Replace TVA's Highly Non-Economic Coal Units*. Synapse Energy Economics for Sierra Club.

Woolf, T., E. Malone, K. Takahashi, W. Steinhurst. 2012. *Best Practices in Energy Efficiency Program Screening: How to Ensure that the Value of Energy Efficiency is Properly Accounted For*. Synapse Energy Economics for National Home Performance Council.

Takahashi, K., W. Steinhurst. 2012. A Preliminary Analysis of Energy Impacts from Partial Deep Energy Retrofit Projects in National Grid's Jurisdiction. Synapse Energy Economics for National Grid, USA.

Synapse Energy Economics. 2012. *Economic and Environmental Analysis of Residential Heating and Cooling Systems: A Study of Heat Pump Performance in US Cities.* Prepared for a HVAC manufacture company.

Hornby, R., D. White, T. Vitolo, T. Comings, K. Takahashi. 2012. *Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky*. Synapse Energy Economics for Mountain Association for Community Economic Development and The Kentucky Sustainable Energy Alliance.

Keith, G., B. Biewald, E. Hausman, K. Takahashi, T. Vitolo, T. Comings, P. Knight. 2011. *Toward a Sustainable Future for the US Power Sector: Beyond Business as Usual 2011.* Synapse Energy Economics for Civil Society Institute.

Synapse Energy Economics. 2011. *Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011.* Prepared for Vermont Department of Public Service.

Bourgeois, T., D. Hall, W. Steinhurst, K. Takahashi. 2011. *Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: A Summary Analysis of DG Benefits and Case Studies***.** Pace Energy and Climate Center and Synapse Energy Economics for New York State Energy Research and Development Authority (NYSERDA).

Peterson, P., V. Sabodash, K. Takahashi. 2010. *Demand Side Resource Potential: A Review of Global Energy Partners' Report for Midwest ISO.* Synapse Energy Economics for Project for Sustainable FERC Energy Policy.

Keith, G., B. Biewald, E. Hausman, K. Takahashi, T. Vitolo, T. Comings, P. Knight. 2010. *Beyond Business as Usual: Investigating a Future Without Coal and Nuclear Power in the US.* Synapse Energy Economics for Civil Society Institute.

Napoleon, A., W. Steinhurst, M. Chang, K. Takahashi, R. Fagan. 2010. *Assessing the Multiple Benefits of Clean Energy: A Resource for States*. US Environmental Protection Agency with research and editorial support from Stratus Consulting, Synapse Energy Economics, Summit Blue, Energy and Environmental Economics, Inc., Demand Research LLC, Abt Associates, Inc., and ICF International.

James, C., K. Takahashi, W. Steinhurst. 2009. *North Dakota Energy Efficiency Potential Study Report.* Synapse Energy Economics for Plains Justice.

James, C., K. Takahashi, W. Steinhurst. 2009. *South Dakota Energy Efficiency Potential Study Report.* Synapse Energy Economics for Plains Justice.

James, C., J. Fisher, K. Takahashi, B. Warfield. 2009. *No Need to Wait: Using Energy Efficiency and Offsets to Meet Early Electric Sector Greenhouse Gas Targets*. Synapse Energy Economics for Environmental Defense Fund.

Takahashi, K., D. Nichols. 2009. *The Costs of Increasing Electricity Savings through Utility Efficiency Programs: Evidence from US Experience*. Proceeding of the 5th International Conference on Energy Efficiency in Domestic Appliances and Lighting (EEDAL'09), June 24, 2009.

Hurley, D., K. Takahashi, B. Biewald, J. Kallay, R. Maslowski. 2008. *Cost and Benefits of Electric Utility Energy Efficiency in Massachusetts*. Synapse Energy Economics for Northeast Energy Efficiency Council.

Takahashi, K., D. Nichols. 2008. *The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date*. Proceedings of the 2008 ACEEE Summer Study on Energy Efficiency in Buildings, August 20, 2008.

Hornby, R., C. Salamone, S. Perry, D. White, K. Takahashi. 2008. *Advanced Metering Infrastructure-Implications for Residential Customers in New Jersey*. Synapse Energy Economics for New Jersey Division of the Ratepayer Advocate.

Hornby, R., C. James, K. Takahashi, D. White. 2008. *Increasing Demand Response in Maine.* Synapse Energy Economics for the Maine Public Utilities Commission.

Hausman, E., R. Fagan, D. White, K. Takahashi, A. Napoleon. 2007. *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumer.* Synapse Energy Economics for the American Public Power Association.

Zalcman, F., K. Takahashi, G. Keith, W. Steinhurst. 2006. *A Comprehensive Process Evaluation of Early Experience under New York's Pilot Program for Integration of Distributed Generation in Utility System Planning.* Synapse Energy Economics and Pace Law School Energy Project for New York State Energy Research and Development Authority (NYSERDA).

Chernick, P., J. Wallach, W. Steinhurst, T. Woolf, A. Sommer, and K. Takahashi. 2006. *Integrated Portfolio Management in a Restructured Supply Market*. Resource Insight, Inc. and Synapse Energy Economics for Ohio Consumers' Counsel.

Steinhurst, W., A. Napoleon, K. Takahashi. 2006. *Energy in the Northern Forest Region: A Situation Analysis*. Synapse Energy Economics for Northern Forest Center and The North Country Council.

Synapse Energy Economics. *Ensuring Delaware's Energy Future: A Response to Executive Order Number 82*. Technical assistance for Delaware Cabinet Committee on Energy.

Hausman, E., K. Takahashi, D. Schlissel, B. Biewald. 2006. *The Proposed Broadwater LNG Import Terminal - An Analysis and Assessment of Alternatives*. Prepared for Connecticut Fund for the Environment and Save the Sound.

Synapse Energy Economics. 2006. *The Glebe Mountain Wind Energy Project: Assessment of Project Benefits for Vermont and the New England Region*. Prepared for Glebe Mountain Wind Energy, LLC.

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

Fagan, R., A. Napoleon, A. Rochelle, A. Sommer, W. Steinhurst, D. White, K. Takahashi. 2006. *Mohave Alternatives and Complements Study: Assessment of Carbon Sequestration Feasibility and Markets.* Sargent & Lundy and Synapse Energy Economics, Inc. for Southern California Edison.

Johnston, L., K. Takahashi, F. Weston, and C. Murray. 2005. *Rate Structures for Customers with Onsite Generation: Practice and Innovation*. Synapse Energy Economics and Regulatory Assistance Projects for National Renewable Energy Laboratory.

Woolf, T., K. Takahashi, G. Keith, A. Rochelle, P. Lyons. 2005. *Feasibility Study of Alternative Energy and Advanced Energy Efficiency Technologies for Low-Income Housing in Massachusetts*. Synapse Energy Economics for Low-Income Energy Affordability Network (LEAN) and Action for Boston Community Development, and Action Inc.

Steinhurst, W., R. McIntyre, B. Biewald, C. Chen, K. Takahashi. 2005. *Economic Impacts and Potential Air Emission Reductions from Renewable Generation & Efficiency Programs in New England.* Prepared for Regulatory Assistance Project.

Keith. G., B. Biewald, K. Takahashi. 2004. *The Searsburg/Readsboro Wind Project: An Analysis of Project Economics and an Analysis of Need*. Synapse Energy Economics for enXco Inc.

Takahashi, K. 2003. "The Clean Development Mechanism and Energy Efficiency Upgrades in Developing Countries: The Case of the Residential Sector in Selected Asian Countries." Proceedings of the 3rd International Conference on Energy Efficiency in Domestic Appliances and Lighting, October 1-3, 2003.

PRESENTATIONS

Hopkins, A. S., S. Kwok, A. Napoleon, K. Schultz, K. Takahashi. "Massachusetts Clean Heat Standard: Policy and Regulatory Analysis" presented with Conservation Law Foundation, February 2023.

Takahashi, K. 2022. "Toward Net Zero Emissions from Oregon Buildings – Emissions and Cost Analysis of Efficient Electrification," presentation at LBNL Webinar: End-Use Load Profiles for the U.S. Building Stock: Data Access and Use Cases, December 2022.

Takahashi, K. 2022. "Missed Opportunities - Impacts of Recent Policies on Energy Efficiency Programs in Midwestern States" Presentation at the ACEEE 2022 Summer Study on Energy Efficiency in Buildings, August 24, 2022.

Shipley, J., Hopkins, A., Takahashi, K., & Farnsworth, D. "Renovating regulation to electrify buildings: A guide for the handy regulator," presented with Regulatory Assistance Project, January 2021.

Takahashi, K. 2019. "Non-Wires Alternatives to Building a New Substation in Washington, D.C. – Key Takeaways for Other Jurisdictions" Presentation at the ACEEE 2019 National Conference on Energy Efficiency as a Resource, October 16, 2019

Titus, E., K. Takahashi. 2019. "Strategic Electrification: What does the promised land of information look like?" Presentation at the AESP 2019 Conference, January 24, 2019.

Hopkins, A., K. Takahashi. 2019. "What's Available and What's Needed for Strategic Electrification Planning and Forecasting in the Northeast Slides" Presentation on behalf of the Northeast Energy Efficiency Partnerships, September 20, 2018.

Hall, J., J. Kallay, A. Napoleon, K. Takahashi, M. Whited. 2018. "Locational and Temporal Values of Energy Efficiency and other DERs to T&D Systems." Presentation at the 2018 ACEEE Summer Study on Energy Efficiency in Buildings, August 15, 2008.

Hopkins. A., K. Takahashi, D. Lis. 2018. Deep Decarbonization through Strategic Electrification in the Northeast. Presentation at the 2018 ACEEE Summer Study on Energy Efficiency in Buildings, August 13, 2008.

Takahashi, K. 2017. "Using Demand-Side Resources to End a Moratorium on New Customers for a Local Natural Gas Company in Massachusetts." Presentation at the ACEEE 2017 National Conference on Energy Efficiency as a Resource, October 31, 2017.

Takahashi, K., R. Cook, T. Comings, A. Allison, E. Malone. 2017. *Rhode Island Renewable Thermal Market Development Strategy – An Analysis of Energy, Environmental, Economic, Energy Bill, and Local Job Impacts of an Alternative Renewable Thermal Energy Future for Rhode Island*. Synapse Energy Economics and Meister Consultants Group. Paper presented by K. Takahashi at the 9th International Conference on Energy Efficiency in Domestic Appliances and Lighting (EEDAL), September 15, 2017.

Napoleon, A., K. Takahashi. 2016. "Assessing Strategic Energy Management Cost Effectiveness." Presentation at NEEP Northeast Strategic Management Collaborative Workshop, November 15, 2016.

Takahashi, K. 2016. "Progress and Prospect of U.S. Electricity Policies." Presentation at the Citizen's Alliance for Saving the Atmosphere and the Earth (CASA) seminar in Osaka, Japan on July 5, 2016.

Takahashi, K. and J. Kallay. 2015. “Energy Efficiency and the Clean Power Plan.” Webinar presentation on December 15, 2015.

Takahashi, K. 2015. “Searching for Best Practices for Modeling Energy Efficiency in Integrated Resource Planning.” Presentation at the 2015 ACEEE National Conference on Energy Efficiency as a Resource, September 21, 2015.

Takahashi, K. 2014. “Expected U.S. Climate and Environmental Policy: The Future of Coal Power and Clean Energy.” Presentation at the Citizen's Alliance for Saving the Atmosphere and the Earth (CASA) seminar in Osaka, Japan on July 10, 2014.

Takahashi, K. and J. Fisher. 2013. “Greening TVA: Leveraging Energy Efficiency to Replace TVA’s Highly Uneconomic Coal Units.” Presentation at the 2013 ACEEE National Conference on Energy Efficiency as a Resource, September 23, 2013.

Takahashi, K. 2013. “Economic and Environmental Analysis of Residential Heating and Cooling Systems: A Study of Heat Pump Performance in U.S. Cities.” Presentation at the 7th International Conference on Energy Efficiency in Domestic Appliances and Lighting (EEDAL’13), September 12, 2013.

Takahashi K. 2011. “Jiyuka-dakedenai-america-no-denryokuseisaku-no-saishin-doukou (Recent Trends in U.S. Electric Power Regulation and Policy).” Presentation at CASA and Hinodeya Eco-life Research Institute in Osaka, Japan Workshop to discuss (1) US electricity regulation, (2) the impact of the Fukushima nuclear event on the US nuclear power industry, and (3) energy efficiency policies and programs in the US, November 21, 2011.

Takahashi, K. 2010. “Review of Utility-Owned Distributed Generation Models for New York.” Presentation at the Northeast CHP Initiative Meeting, April 13, 2010.

Takahashi, K. and D. Nichols. 2009. “The Costs of Increasing Electricity Savings through Utility Efficiency Programs: Evidence from US Experience.” Presentation at the 5th International Conference on Energy Efficiency in Domestic Appliances and Lighting (EEDAL’09), June 24, 2009.

Takahashi, K. 2008. “The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date.” Presentation at the 2008 ACEEE Summer Study on Energy Efficiency in Buildings, August 21, 2008.

Takahashi, K. 2005. Discussant at the World Bank Expert Workshop on CDM methodologies and Technical Issues Associated with Power Generation and Power Saving Activities, December 3, 2005.

OTHER RELEVENT WORK

- Assisted NYSERDA with developing (a) a database of renewable heating and cooling (RH&C) technologies, (b) an Excel-based tool to analyze benefits and costs of RH&C, and (c) a state RH&C Policy Framework titled “Renewable Heating and Cooling Policy Framework: Options to Advance Industry Growth and Markets in New York.”
- Assisted U.S. EPA with its analysis for and preparation for technical support documents on energy efficiency associated with U.S. EPA’s Clean Power Plan under 111(d) regulation

- Assisted New Jersey Division of Rate Counsel with reviewing and commenting on various energy related proposals and documents in New Jersey including utility and the state energy efficiency programs and the state's energy plans. 2009 to 2020.
- Assisted Nova Scotia Utility and Review Board with a review of energy efficiency potential and integrated resource planning for Nova Scotia Power's jurisdiction. 2013
- Assisted the Hawaii Division of Consumer Advocacy in proceedings to develop and review IRPs for three electric companies and to review the state's energy efficiency programs. 2012 to 2014.
- Assisted the Arkansas Public Service Commission staff with (a) reviewing and assessing utility integrated resource planning and energy efficiency program proposals and (b) drafting regulatory orders on comprehensive energy efficiency program designs and reporting methods. 2012 to 2013.
- Assumed a general contractor role for renovating an existing multi-family house into an ultra-low energy use house equipped with state-of-art energy efficiency measures (such as R-7 windows, R-70 roof insulation, a 95 percent efficient energy recovery ventilation system, cold climate heat pumps) and a 5 kW solar photovoltaic system. December 2012.
- Assisted Nova Scotia Utility and Review Board with developing Community Based Feed-In Tariffs (COMFITs) for five different technologies: small wind projects, medium-sized wind projects, small hydro, small tidal, and biomass CHP projects. April 2011.
- Analyzed existing deep energy retrofit (DER) project data and analyzed potential energy savings from model partial DER projects (e.g., attic, above-grade wall, windows, basement wall) using REM/Rate building energy software and Synapse's own spreadsheet building energy model developed for this research project. The results from the analysis were used to project energy savings from and to set incentive levels for partial DER projects as part of National Grid's 2013-2015 efficiency program filing.
- Assisted several states, including Alaska, Colorado, Florida, Maryland, Massachusetts, and South Carolina with developing and analyzing their state climate change action plans; evaluated costs and benefits of demand and supply-side policy options, including quantifying expected greenhouse emission reductions. 2007 to 2010.
- Arranged meetings for Union Fenosa/Gas Natural, a Spanish electric and gas company, with Japanese and Korean organizations to study energy efficiency technologies, programs and policies in those countries; Visited Japanese organizations with the delegates of Union Fenosa, provided them technical and translation assistance on energy efficiency in Japan. July 26 to July 31, 2009.

CONFERENCES

- 2022 ACEEE Summer Study on Energy Efficiency in Buildings, August 24, 2022.
- 2019 ACEEE National Conference on Energy Efficiency as a Resource, October 15, 2019
- 2019 Electrification U.S. Symposium Series – Pathways to Decarbonization in the Northeast, August 27-29, 2019.
- 2019 AESP Annual Conference, January 24, 2019.

- 2018 ACEEE Summer Study on Energy Efficiency in Buildings, August 12, 2018.
- 2017 ACEEE National Conference on Energy Efficiency as a Resource, October 30, 2017.
- 9th International Conference on Energy Efficiency in Domestic Appliances and Lighting (EEDAL'17), September 13-15, 2017.
- NEEP Northeast Strategic Energy Management Collaborative Workshop, November 15, 2016.
- NEEP 2016 EM&V Forum Annual Public Meeting: the Future of Evaluation, March 30, 2016.
- 2015 ACEEE National Conference on Energy Efficiency as a Resource, September 21, 2015.
- EUCI Conference on Utility Integrated Resource Planning (IRP), May 13-15, 2015.
- 2013 ACEEE National Conference on Energy Efficiency as a Resource, September 22-24, 2013.
- 7th International Conference on Energy Efficiency in Domestic Appliances and Lighting (EEDAL'13), September 11-13, 2013.
- Energy Measure Verification Workshop (sponsored by Massachusetts Department of Energy Resources), September 2013.
- Smart Building: High Performance Homes - Workshop for building professionals, June 22, 2011.
- NESEA Building Energy 11 Conference, March 8-10, 2011.
- Build Boston 2010 on Residential Design and Construction, November 17, 2010.
- ACI New England Conference 2010, October 6, 2010.
- 2010 ACEEE Summer Study on Energy Efficiency in Buildings, August 18-20, 2010.
- NESEA Building Energy 10 Conference, March 8-10, 2010.
- 5th International Conference on Energy Efficiency in Domestic Appliances and Lighting (EEDAL'09), June 24, 2009.
- 2008 ACEEE Summer Study on Energy Efficiency in Buildings, August 21, 2008.
- Tufts University Clean Distributed Energy Workshop, June 8, 2006.
- The 2006 Northeast Energy Efficiency Summit, May 17.
- The 2006 Distributed Generation & Interconnection Conference held by DTE Energy, April 26-28, 2006.
- United Nations Climate Change Conference at its eleventh session / Twenty-third sessions of the Subsidiary Bodies and COP/MOP 1, December 2005.

Resume updated July 2025

Case No. 9707, Phase II
Baltimore Gas and Electric Co.
Response to OPC Data Request 1
Request Received: February 13, 2026
Response Date: March 02, 2026
Sponsor(s): Brian M. Scheerer

Item No.: OPCDR01-05

Please refer to the Future Issues section of the Gas Capacity Plan.

(a) Please explain whether the following were considered in developing the Design Day demand estimates used in the Gas Capacity Plan:
  (i) observed climate trends
  (ii) building electrification (including heat pumps) and fuel switching
  (iii) end-use efficiency improvements.

(b) If any of the factors referenced in part a) of this question were not considered, please state whether their exclusion was a deliberate methodological decision and explain the rationale.

RESPONSE:

To the extent these items are inherent in actual observed customer behavior, they are considered in Design Day demand forecasting as described in Company Exhibit BMS-2.

Case No. 9707, Phase II
Baltimore Gas and Electric Co.
Response to OPC Data Request 1
Request Received: February 13, 2026
Response Date: March 02, 2026
Sponsor(s): Brian M. Scheerer

Item No.: OPCDR01-06

Please state whether BGE develops an annual or seasonal forecast of natural gas demand for its Maryland gas system (e.g., annual throughput, winter demand, or average-day demand).

(a) If yes, please identify the forecast(s), including the forecast horizon and customer classes covered.
(b) If no, please explain how BGE evaluates trends in overall gas demand for planning purposes.

RESPONSE:

From a pipeline capacity planning perspective, the only forecast BGE performs is the Design Day calculation. As stated beginning on page 5 of the Direct Testimony of Company Witness Scheerer, this forecast is the required basis for Provider of Last Resort (POLR) pipeline capacity planning. The Design Day calculation is also used to determine whether BGE may engage in winter-term off-system sales or capacity releases under its Merchant Services Program, as described beginning on page 19 of the Direct Testimony of Company Witness Scheerer.

BGE does not perform any other annual or seasonal forecasts of natural gas demand for its Maryland Gas System, as gas supply volumes are not purchased on an annual or seasonal schedule. As further stated in Summary of Issues and Main Conclusions of the Direct Testimony of Company Witness Scheerer, supply planning is intentionally short-term in nature. Prior to each month, BGE uses historical demand data to identify potential high- and low-sendout days for the upcoming month. These projections inform monthly baseload supply purchases, storage planning, and any potential monthly off-system sales or capacity releases. Once the month begins, BGE relies on near-term weather forecasts to develop short-term sendout projections, which guide daily storage withdrawals, supply purchases, and off-system sales or capacity releases.

Columbia Gas of Maryland, Inc.

Docket No. 9707, Phase II
Data Requests

Office of People's Counsel
Set 1

All of the data requests in this set pertain to Issue 1 which states "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." (Order No. 91791 at 7).

Question No. OPC 1-003:

Please refer to the discussion of historical temperature frequencies and winter demand in Special Master 1-001 Attachment B (SGSP, Sections III.D and III.E, pp. 20–21). Please identify the historical period of weather and demand or throughput data used to develop the Design Day demand forecast, including the earliest and latest years considered, and explain why that period was selected.

Response:

Please note that Special Master 1-001 Attachment B references the 2024 Design Day Forecast. The 2025 Design Day Forecast was provided as Special Master 1-001 Attachment A. This response is answered with regard to the 2024 Design Day Forecast. The method for developing the Design Day Forecast did not change between 2024 and 2025.

Each winter, the Company estimates the current Design Day demand by regressing actual throughput on a variety of weather and day-type variables for the current winter and prior winter December – February period. Using only the prior two winters ensures that the estimated Design Day demand is representative of the current customer base.

Future Design Day demands are estimated by taking the prior 20 years of Design Day demands and regressing on a variety of variables meant to capture long-term trends such as changing customer base, changing efficiency in appliances, and economic trends. For the 2024 Design Day Forecast, this started with winter 2024/25.

See Case No 9707 Phase II OPC 1-016 Attachment D pages 6-12 for more details of the development of the Design Day demand forecast.

Columbia Gas of Maryland, Inc.

Docket No. 9707, Phase II
Data Requests

Office of People's Counsel
Set 1

All of the data requests in this set pertain to Issue 1 which states "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." (Order No. 91791 at 7).

Question No. OPC 1-004:

Please refer to the description of historical frequencies of peak day temperatures in Special Master 1-001 Attachment B (SGSP, Section III.D, p. 20; Exhibit III.3, p. 24). Please explain how the Company identified the historical days used to estimate Design Day demand, including:

(a) Whether the analysis is based on the coldest daily average temperature in each winter season, the highest observed system throughput, or another criterion;

(b) Whether more than one peak day per winter was considered; and

(c) How anomalous operational days were identified and treated.

Response:

Please note that Special Master 1-001 Attachment B references the 2024 Design Day Forecast. The 2025 Design Day Forecast was provided as Special Master 1-001 Attachment A. This response is answered with regards to the 2024 Design Day Forecast. The method for developing the Design Day Forecast did not change between 2024 and 2025.

a-b. There are two separate steps to estimating Design Day demand that this question conflates. First is selecting design conditions on all historical weather data. The second is developing an estimate for Design Day demand by regressing actual throughput on actual weather conditions and then applying the design conditions to the resulting regression equations.

See response to OPC 1-002 for more information regarding the development of design weather conditions.

See response to OPC 1-003 for more information regarding the development of Design Day estimates.

c. When developing Design Day demand estimates for a given winter, outliers are manually identified as days which have a lower than expected or higher than expected demand based on weather and day-type conditions. These are visually identified by graphing demand as a dependent variable of the independent variable gas day average temperature. Outliers are removed from the regressions if their exclusion improves the accuracy of the demand model.

Columbia Gas of Maryland, Inc.

Docket No. 9707, Phase II
Data Requests

Office of People's Counsel
Set 1

All of the data requests in this set pertain to Issue 1 which states "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." (Order No. 91791 at 7).

Question No. OPC 1-014:

Please refer to the discussion of projected demand and strategic issues in Special Master 1-001 Attachment B (SGSP, Chapters II and III, pp. 9–25). Please explain whether and how the Company considered the following when estimating current or future Design Day demand:

(a) end-use efficiency improvements

(b) fuel switching and electrification

(c) long-term temperature or climate trends

(d) state or local energy or decarbonization policies

Response:

a. Design Day demand is estimated using actual historical throughput so these effects are being indirectly captured to the extent that any impacts of end-use efficiency improvements may have had on that historical throughput. The Company does not directly use end-use efficiency improvements as an input when estimating current or future Design Day demand.

b. Design Day demand is estimated using actual historical throughput so these effects are being indirectly captured to the extent that any impacts of fuel switching and electrification may have had on that historical throughput. The Company does not directly use fuel switching and electrification as an input when estimating current or future Design Day demand.

c. The Company considers long-term temperature or climate trends by regularly updating Design Day weather conditions and expected normal weather using all historical weather data. See response to OPC 1-002 for more information about the development of Design Day weather conditions. Normal weather is one of the inputs used to estimate future Design Day demand, so any changes to expected normal weather will adjust those estimates. See Special Master 1-001 Attachment A – CMD 2025 Design Day Forecast pages 9-10 for more information about how future Design Day demands are estimated.

d. Design Day demand is estimated using actual historical throughput so any changes, including to any government policies, resulting in measurable effects are being indirectly captured to the extent it is shown in historical throughput.

Columbia Gas of Maryland, Inc.

Docket No. 9707, Phase II
Data Requests

Office of People's Counsel
Set 1

All of the data requests in this set pertain to Issue 1 which states "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." (Order No. 91791 at 7).

Question No. OPC 1-016:

Please refer to the Company's discussion of Design Day forecasting and supply–demand balancing models in Special Master 1-001 Attachment B (SGSP, Sections III.F and VI.A, pp. 21 and 36). Please provide all workpapers, data files, models, spreadsheets, calculations, and supporting documentation sufficient to reproduce the Company's Design Day demand forecast.

Objection: Columbia objects to this request to the extent it seeks information regarding practices and procedures that have been reviewed and approved in Case No. 9510, a case in which OPC fully participates. Further, Columbia objects to this request to the extent it seeks information outside the scope of this matter, as specifically directed by the Public Service Commission in Order No. 91683 (dated June 13, 2025), at page 14. In addition, Columbia objects to this request, as the term "sufficient to reproduce" is ambiguous and lacks specificity. This request's directive to "provide all workpapers, data files, etc." is overly broad, unduly burdensome and lacks specificity in the material sought. Without waiving the foregoing objections, Columbia provides the following response:

Response:

Please note that Special Master 1-001 Attachment B references the 2024 Design Day Forecast. The 2025 Design Day Forecast was provided as Special Master 1-001 Attachment A. This response provides workpapers to the 2024 Design Day Forecast. The method for developing the Design Day Forecast did not change between 2024 and 2025.

See OPC 1-016 CONFIDENTIAL Attachments A, B, and C as well as OPC 1-016 Attachments E and F for the workpapers used in developing the 2024 Design Day Forecast. See OPC 1-016 Attachment D pages 6-12 for discussion of the development of the Design Day Forecast.

2024 Design Day Forecast, 2024/25 – 2028/29 By Pipeline Scheduling Point (PSP)

Columbia Gas of Maryland

NiSource

Forecast Developed by Energy Supply & Optimization

COLUMBIA GAS OF MARYLAND

2024 DESIGN DAY FORECAST, 2024/25 – 2028/29

TABLE OF CONTENTS

COLUMBIA GAS OF MARYLAND

2024 DESIGN DAY FORECAST, 2024/25 – 2028/29

LIST OF SCHEDULES

Exhibit D: 90% Probability Date of Design Current Day Temperature Occurrence

Exhibit E: Winter Historical Information

COLUMBIA GAS OF MARYLAND

2024 DESIGN DAY FORECAST, 2024/25 - 2028/29

I. Introduction

The 2024 Design Day Forecast (DDF) for Columbia Gas of Maryland (CMD or Company) as developed by the NiSource Energy Supply and Optimization Group (ES&O), represents the official estimate of CMD's Design Day Demand for each of the winters 2024/25 through 2028/29. The DDF is a key-planning tool for CMD in the design of its design day supply/capacity portfolio to fulfill CMD's service obligations to firm customers. It is also critical to day-to-day operations since it serves as the foundation for CMD's daily demand forecasts. As a result, it is imperative that CMD quantify the firm and total demand expected at CMD's Design Day Conditions to ensure continuous, reliable, and economic service to its customers over the term of the forecast.

The projected Design Day Demand quantities contained within are based on CMD's Design Day Conditions, which consist of the Design Current Day Temperature, Design Prior Day Temperature, and Design Current Day Wind Speed, that are assumed to occur on a weekday. These conditions, as discussed in the Appendix and shown on **Exhibit A**, are incorporated in IBM SPSS statistics software to generate predictive equations for CMD's DDF. The resultant forecast provides Design Day Demand estimates by:

1) Revenue Class: Residential, Commercial, Industrial, and "Other",
2) Priority of Service: Firm and Non-Firm,
3) Type of Service: Sales, Choice, and Transportation, and
4) Pipeline Scheduling Point (PSP), as designated by CMD's supplying pipeline.

In addition to the forecasts of Design Day Demand, the DDF also provides each month's estimated daily maximum and minimum demands that may be factored into CMD's supply planning and daily operational processes.

For technical details pertaining to the development of the forecast, including statistical methods used and development of design conditions, please refer to the Appendix, at the end of this document.

II. Executive Summary

The DDF provides a projection of firm and non-firm demand expected to occur at CMD's Design Day Conditions for each of the next five years ending with the 2028-2029 winter. The process behind the development of CMD's 2024 DDF is consistent with that used for CMD's 2023 DDF.

Table 1 provides a breakdown of forecast quantities by service priority (firm and non-firm). The demand of General Distribution Services customers not supported by the Company's Standby Service or Elective Balancing Service (EBS) is considered to be non-firm. All remaining demand is considered to be firm and would include CMD's firm obligation to transportation customers who have contracted for Standby Service or EBS. The 2011/12 heating season was the last to reflect Choice quantities, hence there are no Choice quantities reflected in this document.

Table 1
Columbia Gas of Maryland
2024 Design Day Forecast
Quantities in MDth

Winter	Firm					Non-Firm	Total Demand	Standby Service	EBS	Total Firm Obligation
	Sales	Choice	STS	Other	Total					
	(1)	(2)	(3)	(4)	(5)=(1 thru 4)	(6)	(7) = (5 + 6)	(8)	(9)	(10)=(5+8+9)
2023/24	51.8	0.0	0.0	0.1	52.0	14.3	66.3	1.5	0.7	54.2
2024/25	52.1	0.0	0.0	0.1	52.2	14.8	67.0	1.4	0.7	54.3
2025/26	52.5	0.0	0.0	0.1	52.6	15.4	68.0	1.4	0.7	54.7
2026/27	52.8	0.0	0.0	0.1	52.9	15.4	68.4	1.4	0.7	55.0
2027/28	53.1	0.0	0.0	0.1	53.2	15.4	68.7	1.4	0.7	55.3
2028/29	53.4	0.0	0.0	0.1	53.5	15.4	68.9	1.4	0.7	55.6
CAG 2024/25-2028/29					0.6%	1.0%	0.7%			0.6%

Schedule 1 presents the 2024 DDF in more detail, identifying the forecast by customer class and segregated by Pipeline Scheduling Point (PSP) as well as by priority of service.

The growth rates shown in Table 1 are for CMD in total. **Schedule 1** provides the same information by PSP and shows differences in growth across CMD's service territory. As mentioned in last year's DDF the Company eliminated the Choice program after September 2012 billing. Schedules 1 and 2 show Choice demand set to 0.0 MDth.

On **Schedule 2**, CMD's firm service obligations to commercial and industrial customers, including Standby and EBS Obligations, are identified by PSP.

Schedule 3 provides tabular and graphical trends related to firm demand based on historic Design Actual Demands. The Design Actual Demand contained in Column 1 represents ES&O's calculation of what the Design Day Demand would equate to for a given historic winter season (2004/05 through 2023/24) had Design Day Conditions been experienced. The Design Actual Demand serves as the basis for the forecasts of CMD's future Design Day Demand as presented in Column 2, as more fully explained in Section III E – Design Day Forecast. The forecast shows an increase in demand in response to projected gas prices, degree days and annual trend. Column 3 reflects an increase in Design Day Demand attributable to the additional firm obligations of the Standby contract level and EBS contract level. Column 4 (Columns 2 plus 3) is the forecasted Total Firm Obligation.

Schedule 4 parallels **Schedule 3** for Columbia's Total Design Day demand.

III. 2024 DDF Development

Columbia's Design Day Forecast uses two linear regression-based models to develop a forecast of Columbia's expected Design Day Demand for each PSP. The first linear regression-based model is used to determine the Design Actual Demand for each historical winter season. The second regression model is based on an analysis of the Design Actual Demand and determines the Design Day Forecast.

The process is described in sections A through H.

A. Obtaining Actual Total Daily Demand

The first step in the preparation of the DDF is to obtain the actual total daily demand that was observed in the months of December through February for the prior heating seasons. ES&O derives the actual total daily demand by accumulating daily supply data from all sources. Based on twelve months ending December 2023, 97.5% of CMD's total deliveries are measured on a daily basis. The deliveries that are monthly read are allocated to daily volumes using a base load / heat load allocation process. The total daily volume for every Point of Delivery (POD) is then summarized to produce the actual total daily demand for each PSP.

B. Obtaining Non-Firm Customer Daily Demand

The second step is the calculation of the daily demand for CMD's industrial and commercial customers receiving services from the company on a non-firm basis. As shown on **Schedule 5**, approximately 72.5% of total non-firm customer demand is subject to daily measurement. The percentages on **Schedule 5** are based on the actual January 2024 throughput for all such customers. For non-firm customers without daily read capability, CMD estimates their daily consumption using a base load / heat load allocation process. The non-firm quantities are summarized to produce total non-firm deliveries by PSP.

C. Calculation of Daily Firm Demand

Daily Firm Demand is calculated at the PSP level by subtracting the daily non-firm customer (industrial and commercial) demand, as described above, from the actual total daily demand. The resultant daily demand is considered to be firm customer demand, for supply planning purposes, and is utilized in the regression process described below.

As discussed in the Executive Summary section, CMD has additional firm obligations of 2.1 MDth under its Standby Service contracts and EBS contracts with transportation customers for 2024-25. Both Standby Service and EBS projections are held constant over the forecast period. **Schedule 2** provides a breakdown of Standby Service and EBS quantities by revenue class and PSP.

D. Design Actual Demand

A linear regression-based model is used to determine the Design Actual Demand for each historical winter season for Firm Demand, Industrial Non-Firm Demand and Commercial Non-Firm Demand. During the process the actual daily demand for the months of December through February for the past two heating seasons are regressed against four potential explanatory variables for all days and Cold Days (days having an average temperature of 30°F or colder). The potential explanatory variables are:

1) Current Day Temperature: the average daily temperature for the current day,
2) Prior Day Temperature: the average daily temperature for the prior day,
3) Wind Speed: the average daily wind speed for the current day, and
4) Day Type: weekdays, weekends, holidays, Friday, Saturday, and Sunday. The holidays are the period December 24th through January 1st, Martin Luther King Jr. Day, and President's Day. Using SPSS, it was determined that in some instances, certain industrial and commercial customers' demand patterns are affected by the day of the week, i.e., some companies have reduced consumption or shut down starting Friday through Sunday.

For each of these explanatory variables Columbia has determined the associated Design Day Conditions, for each PSP, as discussed in the Appendix. The Design Day Type is considered to be a weekday.

Selection of the Design Actual Demand model will consist of explanatory variables having 95% significance and a selection based on the best statistical results of the regressions. Three statistical tests are developed, R-Square, Durbin-Watson, and Root Mean Square Error (RMSE). An accepted model will have a high R-Square, a Durbin-Watson near 2.000 and a low RMSE. There are some special cases in which a Non-Firm customer's data is so sporadic that a good linear regression is not possible. These customers were identified with SPSS and rather than using the traditional linear regression a special analysis was performed that yielded the best estimate of demand based on a 95% confidence interval.

Schedule 6 summarizes the regression results and provides the coefficient of determination, R^2 for each PSP. The statistic R^2 is "the estimated proportion of the variance of Y (the demand) that can be attributed to its linear regression on X (the collection of explanatory variables)". (Snedecor and Cochran, Statistical Methods, Seventh Edition, page 181.) For those special Non-Firm customers in which an average estimate based on the 95% confidence interval was calculated, there are no statistical results; “95%” has been included in the column heading.

Note that R^2 for the Firm Demand component typically exceeds R^2 for the Industrial demand components. The higher R^2 for Firm Demand indicates that the explanatory variables included in the model account for a high proportion of the day to day variation in demand. The lower R^2 for the industrial models indicates that additional variables not included in the models affect demand. For example, day-to-day production / operations, pricing of alternative fuels may affect industrial demand.

In some PSPs the models have missing coefficients. A missing coefficient indicates that the associated variable does not affect demand with 95 percent confidence. In order to affect demand with 95 percent confidence, an explanatory variable must have an estimated regression coefficient, which is large compared to its standard error. In statistical terms, the probability of obtaining such a large estimated coefficient is less than 5 percent if the true coefficient is zero.

The day type variable includes both holiday and weekend demand impact relative to weekdays. If weekend is found to be a valid explanatory variable, then holiday will have at least the same value as a weekend or may be greater. For Non-Firm (Industrial or Commercial), when applicable, the Friday, Saturday and/or Sunday variables would impact demand. On days when applicable, these day type variables reduce the intercept by the amount shown. Since the forecast is based on weekday, these variables do not impact the Design Day Demand.

Using PSP 19E (Lancaster) as an example, the Daily Firm Demand model includes all the explanatory variables. As shown in **Table 2** the 2023/24 Design Actual Demand for firm customers is 25,149 DTh (excluding Standby and EBS demand) and the equation is:

Daily Firm Demand in DTh = Intercept + (Temperature Coefficient * Current Day Temperature),
+ (Prior Day Temperature Coefficient * Prior Day Temperature),
+ (Wind Speed Coefficient * Wind Speed),
+ Day Type Coefficient.

Since this PSP has customers that have Standby Service and EBS agreements, these obligations need to be included to arrive at the Total Firm Obligation. During the 2023/24 heating season, PSP 19E (Lancaster) had additional firm obligations of 1,025 DTh. Table 2 shows the use of the coefficients to determine the PSP 19E (Lancaster) 2023/24

Design Actual Firm Demand (the weekday firm daily demand that would be expected under Design Conditions) plus the Standby Service and EBS obligations. PSP 19E (Lancaster) had a Total Firm Obligation of 26,174 Dth with a Design Current Day Temperature of 2 degrees, Design Prior Day Temperature of 11 degrees and Design Current Day Wind Speed of 12 MPH.

Table 2
Columbia Gas of Maryland
2024 Design Day Forecast

Use of the Regression Coefficients to Determine 2023/24 Design Actual Demand
Example: System Firm Demand for PSP 19E (Lancaster, TCO Market Area 25)

Explanatory Variable	Regression Coefficient		Design		Product Dth
	Value	Units	Value	Units	
(1)	(2)	(3)	(4)	(5)	(6) = (2) * (4)
Intercept	25,701.35	DTh	1	--	25,701
Temperature	(327.84)	DTh/Deg	2	Deg	(656)
Prior Day Temp.	(70.62)	DTh/Deg	11	Deg	(777)
Wind Speed	73.46	DTh/ MPH	12	MPH	881
Day Type:					
Holiday	(636.84)	DTh	0	--	0
Weekend	(493.69)	DTh	0	--	0
2023/24 Design Actual					**25,149**
Additional Firm Obligations 2023/24					
Standby Service	656.00	DTh	1		656
EBS	368.80	DTh	1		369
2023/24 PSP 19-25 Design Actual Firm Obligation					**26,174**

<u>Schedule 6</u> shows for each PSP the 2023/24 Design Actual Demands and regression components, the forecasted 2024/25 Design Day Demand and the 2024/25 Standby Service and EBS obligations by PSP.

E. Design Day Forecast

Historical Design Actual Demands for each PSP beginning with the 2004/05 Winter are utilized as the basis for the regressions to determine the Design Day Forecast. The analyses at the PSP level are needed for planning purposes and allows for identifying variances in customer demand over the historical period studied. In the process, the impact on the annual Design Actual Demands of four variables is determined. Those variables are:

1. Customer count in the month of January,
2. Actual degree days in the months of December and January,

3. Actual winter period gas cost, and
4. Average Non-Farm Employment in the months of December through February.

These variables were considered in the analysis; a separate analysis was also made using the log of the variables. Both analyses consider an annual trend term to capture appliance efficiency effect on demand and customer demand usage behavior over time.

For log variables, the result generates a forecasted Log of UPC when the regression equation is applied to the forecast of these explanatory variables. The Log of UPC is converted to a UPC and applied to the forecasted January number of customers to arrive at a Design Day Demand. The forecast of January number of customers is derived from the Company's AFP 2025 Gas Estimate.

For the purpose of forecasting both firm and non-firm Design Day Demand, the gas cost is the forecasted January NYMEX Gas Monthly Price at Henry Hub (NGI Bidweek Prices). The prior year's gas price may also be tested as an explanatory variable in combination with other explanatory variables.

This year's forecast continued the use of employment to capture the effect of local economic factors on demand for natural gas. For the purpose of modelling firm and non-firm Design Day Demand, the non-farm employment is the average of monthly December, January, and February employment aggregated to the PSP level. Historical and forecasted employment values come from the 2024 IHS Global Insight County Forecast.

Schedule 7 shows the Firm Design Actual Demand, Non-Firm Design Actual Demand and corresponding forecast for the five year period along with the explanatory variables, resultant statistics, and the number of historical winter periods of the selected model. A model is considered for acceptance when meeting an acceptable threshold of statistical results which include an adjusted R^2 above 0.6, an F-test of model significance resulting in 85% confidence, and explanatory variable coefficients taking the "expected" sign. The expected sign for customer count, degree-day, and non-farm employment is positive and the expected sign for an additional dollar in price is negative. If an acceptable model is not found the forecast reflects the average of the three most recent Design Actual Demands. This year's forecast accepted all four explanatory variables in various combinations, depending on the PSP, which achieved the best statistical results.

The adjustments to the forecast are described in Section F.

F. Adjustments to Forecast

As addressed in Section E above, additional analyses, and adjustments, were required to account for:

- ***Smoothing Process For Design Actual***

The forecast of CMD's firm and non-firm customer demand for the first winter (2024/25) incorporates a smoothing process, which reflects the average of the 2023/24 historical Design Actual Demand and the 2025/26 projected Design Day Demand.

- ***Non-Firm Sales***

  Non-Firm Sales demand is historically reflected in the firm design actuals. However, since it is non-firm, an adjustment was made to decrease firm demand and increase non-firm demand, thereby showing this demand correctly in the forecast.

- ***Adjustments for Projected Large Customer Relations***

  The forecast of CMD's non-firm customer demand has given consideration to the current projection of expected new customer load developed by NiSource's Large Customer Relations group.

Schedule 7 shows each PSP's firm and non-firm Design Actual volume and forecasted firm and non-firm Design Day Demand.

G. Design Day Demand by Revenue Class

The Firm and Non-Firm Design Actual Demand are used in the allocation process to determine Design Day Demand by Revenue Class. This is a multiple step process as explained below.

Three steps are performed to allocate firm customer demand. In **Step 1**, the annual and monthly forecasts reflected in CMD's Gas Estimate are used to calculate Company Use, and Unaccounted For Gas. For the Design Day Forecast, Company Use quantities are calculated to be one-twentieth of the January requirement from the AFP 2025 Gas Estimate. The Design Day Demand of Unaccounted For Gas is calculated to be 1/365th of the annual Unaccounted For Gas load from the AFP 2025 Gas Estimate. Like residential demand, Company Use and Unaccounted For Gas are entirely firm; i.e., they contain no non-firm component. Since Company Use, and Unaccounted For Gas do not have a historical pattern, CMD projects this demand to remain constant.

In **Step 2**, Industrial Firm Sales is developed by regression analysis of the estimated daily industrial firm sales demand of the most recent winter (derived from monthly billing data for December 2023 through February 2024) against the gas-day average temperature.

In **Step 3**, the remainder of Firm Demand (Firm Demand less Industrial Firm Demand less Company Use and Unaccounted For Gas) is allocated to Residential and Firm Commercial based on the forecasted demands from the Company's AFP 2025 Gas Estimate.

H. Results

The 2023/24 Design Actual Demands and five-year Design Day Forecast by revenue class and priority of service are summarized on **Schedule 1**. The forecast includes non-firm demand since it is vital for planning and operations to know potential total (firm and non-firm) demand under Design Day Conditions.

Schedule 8 provides a breakdown of customer demand for the first forecast year of the DDF by Rate Schedule. The allocation of the forecasted commercial and industrial Design Day Demand to the various rate schedules is based on the actual total demand for the month of January 2024, as accounted for by rate schedule. Both the Standby Service obligation and the EBS are reflected on this schedule.

IV. Historical Demands and Supplies

Schedule 9 shows the historic actual peak day demand and associated supply sources for the three consecutive winter days of greatest demand for each of the past four winter seasons. The demands shown represent total throughput, meaning the demand of all customers served by Columbia. The breakdown by revenue class is an estimate since actual daily-metered volumes are not available for all customers and is based on an analysis of billing data. The total demand represents the actual demand of all customers predicated upon the total, measured supply quantities from all sources delivered to CMD for both sales and transportation customers. Also shown are the actual average temperatures, date, and day of week.

V. Monthly Maximum and Minimum Design Conditions and Demands

A. Monthly Maximum Conditions and Corresponding Demand

To serve CMD's planning needs, Monthly Maximum Conditions and associated Forecast Demand are included in the DDF. Monthly Maximum Conditions and Forecast Demand are shown on **Schedule 10**. For a description of how the monthly maximum design conditions and demand are determined, please refer to Section III of the Appendix at the end of this document.

B. Monthly Minimum Demand

The Monthly Minimum Demands, shown on **Schedule 11** are based on the analysis of daily demand that has occurred over the most recent five years for each month. The selection of five years of history is driven by the need to obtain as many observations of actual demand as possible for analysis, while recognizing that the use of more history may provide a result that is not reflective of current customer demand. The total Monthly Minimum Demands are calculated to be the demand having a 10% probability of occurrence.

SCHEDULES

Schedule 1

Columbia Gas of Maryland
2024 Design Day Forecast, 2024/25 - 2028/29

Firm and Total Requirements by Class, Service Type, Priority of Service and Pipeline Scheduling Point
Demand Units are MDth/Day

	Residential			Commercial								Industrial								All Classes			Additional Firm Obligation		Total Firm
			Grand	Firm				Non-Firm			Grand	Firm			Non-Firm			Grand							
Winter	Sales	Choice [1/]	Total	Sales	Choice [1/]	STS	Total	Transpt.	Sales	Total	Total	Sales	Choice	Total	Transpt.	Sales	Total	Total	Other	Firm	Non-Firm	Total	Standby	EBS	Obligation
Total																									
2023/24	30.0	0.0	30.0	21.4	0.0	0.0	21.4	8.4	0.1	8.5	29.9	0.3	0.0	0.3	5.9	0.0	5.9	6.2	0.1	52.0	14.3	66.3	1.5	0.7	54.2
2024/25	32.8	0.0	32.8	19.0	0.0	0.0	19.0	8.8	0.1	8.9	27.9	0.3	0.0	0.3	5.9	0.0	5.9	6.2	0.1	52.2	14.8	67.0	1.4	0.7	54.3
2025/26	33.1	0.0	33.1	19.0	0.0	0.0	19.0	9.4	0.1	9.5	28.5	0.3	0.0	0.3	5.9	0.0	5.9	6.3	0.1	52.6	15.4	68.0	1.4	0.7	54.7
2026/27	33.4	0.0	33.4	19.1	0.0	0.0	19.1	9.4	0.1	9.5	28.5	0.3	0.0	0.3	5.9	0.0	5.9	6.3	0.1	52.9	15.4	68.4	1.4	0.7	55.0
2027/28	33.6	0.0	33.6	19.1	0.0	0.0	19.1	9.4	0.1	9.5	28.6	0.3	0.0	0.3	6.0	0.0	6.0	6.3	0.1	53.2	15.4	68.7	1.4	0.7	55.3
2028/29	33.8	0.0	33.8	19.2	0.0	0.0	19.2	9.3	0.1	9.4	28.6	0.3	0.0	0.3	6.0	0.0	6.0	6.3	0.1	53.5	15.4	68.9	1.4	0.7	55.6
CAG:			0.8%								0.7%							0.4%	0.0%	0.6%	1.0%	0.7%			0.6%
PSP 19E																									
2023/24	14.5	0.0	14.5	10.4	0.0	0.0	10.4	3.4	0.0	3.5	13.8	0.2	0.0	0.2	3.6	0.0	3.6	3.8	0.1	25.2	7.0	32.2	0.7	0.4	26.2
2024/25	15.8	0.0	15.8	9.2	0.0	0.0	9.2	3.9	0.0	3.9	13.1	0.2	0.0	0.2	3.6	0.0	3.6	3.8	0.1	25.2	7.5	32.8	0.6	0.4	26.2
2025/26	15.9	0.0	15.9	9.1	0.0	0.0	9.1	4.5	0.0	4.5	13.7	0.2	0.0	0.2	3.6	0.0	3.6	3.8	0.1	25.4	8.2	33.5	0.6	0.4	26.3
2026/27	16.2	0.0	16.2	9.2	0.0	0.0	9.2	4.7	0.0	4.8	14.0	0.2	0.0	0.2	3.6	0.0	3.6	3.9	0.1	25.7	8.4	34.1	0.6	0.4	26.6
2027/28	16.4	0.0	16.4	9.3	0.0	0.0	9.3	4.9	0.0	5.0	14.3	0.2	0.0	0.2	3.6	0.0	3.6	3.9	0.1	26.0	8.6	34.6	0.6	0.4	26.9
2028/29	16.6	0.0	16.6	9.4	0.0	0.0	9.4	5.1	0.0	5.1	14.5	0.2	0.0	0.2	3.7	0.0	3.7	3.9	0.1	26.2	8.8	35.0	0.6	0.4	27.2
CAG:			1.2%								2.7%							0.3%	0.0%	1.0%	3.9%	1.7%			0.9%
PSP 19-26																									
2023/24	3.6	0.0	3.6	2.5	0.0	0.0	2.5	1.5	0.0	1.6	4.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.1	1.6	7.7	0.0	0.1	6.3
2024/25	3.9	0.0	3.9	2.3	0.0	0.0	2.3	1.5	0.0	1.5	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2	1.5	7.7	0.0	0.1	6.3
2025/26	4.0	0.0	4.0	2.3	0.0	0.0	2.3	1.4	0.0	1.4	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.3	1.4	7.6	0.0	0.1	6.4
2026/27	4.0	0.0	4.0	2.3	0.0	0.0	2.3	1.3	0.0	1.3	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2	1.3	7.6	0.0	0.1	6.4
2027/28	3.9	0.0	3.9	2.3	0.0	0.0	2.3	1.3	0.0	1.3	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2	1.3	7.5	0.0	0.1	6.3
2028/29	3.9	0.0	3.9	2.2	0.0	0.0	2.2	1.3	0.0	1.3	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2	1.3	7.5	0.0	0.1	6.3
CAG:			0.2%								-1.5%							0.0%	0.0%	0.0%	-3.5%	-0.7%			0.0%
PSP 19-27																									
2023/24	10.4	0.0	10.4	7.4	0.0	0.0	7.4	3.1	0.0	3.1	10.5	0.1	0.0	0.1	1.9	0.0	1.9	2.0	0.0	18.0	5.0	23.1	0.8	0.2	19.0
2024/25	11.3	0.0	11.3	6.6	0.0	0.0	6.6	3.1	0.0	3.1	9.7	0.1	0.0	0.1	1.9	0.0	1.9	2.0	0.0	18.1	5.1	23.1	0.8	0.2	19.1
2025/26	11.4	0.0	11.4	6.6	0.0	0.0	6.6	3.1	0.0	3.1	9.7	0.1	0.0	0.1	1.9	0.0	1.9	2.1	0.0	18.2	5.1	23.2	0.8	0.2	19.2
2026/27	11.5	0.0	11.5	6.5	0.0	0.0	6.5	2.9	0.0	2.9	9.5	0.1	0.0	0.1	1.9	0.0	1.9	2.1	0.0	18.2	4.9	23.0	0.8	0.2	19.1
2027/28	11.5	0.0	11.5	6.5	0.0	0.0	6.5	2.7	0.0	2.8	9.3	0.1	0.0	0.1	2.0	0.0	2.0	2.1	0.0	18.1	4.7	22.9	0.8	0.2	19.1
2028/29	11.5	0.0	11.5	6.5	0.0	0.0	6.5	2.6	0.0	2.6	9.1	0.1	0.0	0.1	2.0	0.0	2.0	2.1	0.0	18.1	4.6	22.7	0.8	0.2	19.1
CAG:			0.3%								-1.6%							0.6%	0.0%	0.1%	-2.5%	-0.5%			0.1%
PSP 19-32																									
2023/24	1.5	0.0	1.5	1.1	0.0	0.0	1.1	0.3	0.0	0.3	1.4	0.0	0.0	0.0	0.4	0.0	0.4	0.4	0.0	2.6	0.7	3.3	0.0	0.0	2.7
2024/25	1.7	0.0	1.7	1.0	0.0	0.0	1.0	0.4	0.0	0.4	1.4	0.0	0.0	0.0	0.4	0.0	0.4	0.4	0.0	2.7	0.8	3.5	0.0	0.0	2.8
2025/26	1.8	0.0	1.8	1.0	0.0	0.0	1.0	0.5	0.0	0.5	1.5	0.0	0.0	0.0	0.4	0.0	0.4	0.4	0.0	2.8	0.8	3.6	0.0	0.0	2.8
2026/27	1.8	0.0	1.8	1.0	0.0	0.0	1.0	0.4	0.0	0.4	1.5	0.0	0.0	0.0	0.4	0.0	0.4	0.4	0.0	2.9	0.8	3.7	0.0	0.0	2.9
2027/28	1.8	0.0	1.8	1.0	0.0	0.0	1.0	0.4	0.0	0.4	1.5	0.0	0.0	0.0	0.4	0.0	0.4	0.4	0.0	2.9	0.8	3.7	0.0	0.0	3.0
2028/29	1.9	0.0	1.9	1.1	0.0	0.0	1.1	0.4	0.0	0.4	1.5	0.0	0.0	0.0	0.4	0.0	0.4	0.4	0.0	3.0	0.8	3.7	0.0	0.0	3.0
CAG:			5.3%								1.7%							0.5%	0.0%	2.3%	0.9%	2.0%			2.2%

CAG = Compound Annual Growth 2024/25 - 2028/29

[1/] CMD's Choice program ended effective October 2012.

Schedule 2

Columbia Gas of Maryland
2024 Design Day Forecast, 2024/25 - 2028/29

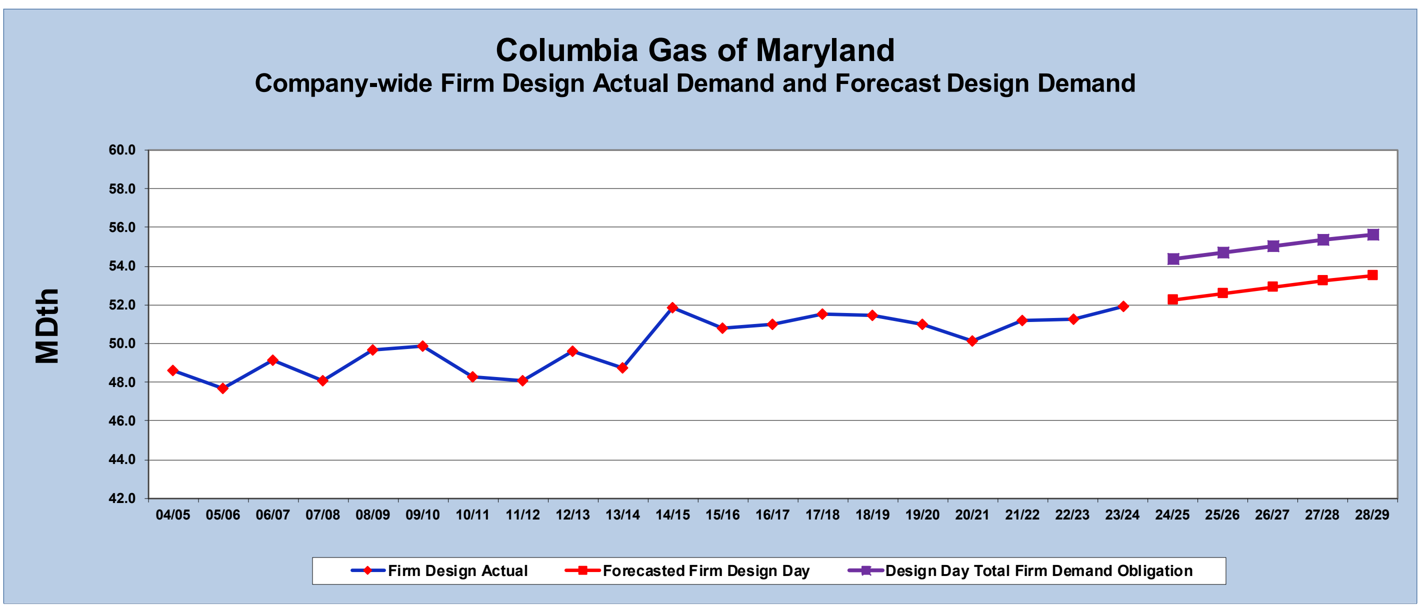
Commercial and Industrial Design Day Firm Obligation
Demand Units are Dth/Day

	Commercial						Industrial				
Winter	Sales	Choice	STS	Standby	EBS	Firm Obligation	Sales	Choice	Standby	EBS	Firm Obligation
Total											
2023/24	21.4	0.0	0.0	1.5	0.1	23.0	0.3	0.0	0.0	0.6	0.9
2024/25	19.0	0.0	0.0	1.4	0.1	20.4	0.3	0.0	0.0	0.6	0.9
2025/26	19.0	0.0	0.0	1.4	0.1	20.5	0.3	0.0	0.0	0.6	0.9
2026/27	19.1	0.0	0.0	1.4	0.1	20.5	0.3	0.0	0.0	0.6	0.9
2027/28	19.1	0.0	0.0	1.4	0.1	20.6	0.3	0.0	0.0	0.6	0.9
2028/29	19.2	0.0	0.0	1.4	0.1	20.7	0.3	0.0	0.0	0.6	0.9
PSP 19E											
2023/24	10.4	0.0	0.0	0.7	0.1	11.1	0.2	0.0	0.0	0.3	0.5
2024/25	9.2	0.0	0.0	0.6	0.1	9.9	0.2	0.0	0.0	0.3	0.5
2025/26	9.1	0.0	0.0	0.6	0.1	9.8	0.2	0.0	0.0	0.3	0.5
2026/27	9.2	0.0	0.0	0.6	0.1	9.9	0.2	0.0	0.0	0.3	0.5
2027/28	9.3	0.0	0.0	0.6	0.1	10.0	0.2	0.0	0.0	0.3	0.5
2028/29	9.4	0.0	0.0	0.6	0.1	10.1	0.2	0.0	0.0	0.3	0.5
PSP 19-26											
2023/24	2.5	0.0	0.0	0.0	0.0	2.6	0.0	0.0	0.0	0.1	0.1
2024/25	2.3	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	0.1	0.1
2025/26	2.3	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	0.1	0.1
2026/27	2.3	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	0.1	0.1
2027/28	2.3	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	0.1	0.1
2028/29	2.2	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	0.1	0.1
PSP 19-27											
2023/24	7.4	0.0	0.0	0.8	0.0	8.2	0.1	0.0	0.0	0.2	0.3
2024/25	6.6	0.0	0.0	0.8	0.0	7.3	0.1	0.0	0.0	0.2	0.3
2025/26	6.6	0.0	0.0	0.8	0.0	7.3	0.1	0.0	0.0	0.2	0.3
2026/27	6.5	0.0	0.0	0.8	0.0	7.3	0.1	0.0	0.0	0.2	0.3
2027/28	6.5	0.0	0.0	0.8	0.0	7.3	0.1	0.0	0.0	0.2	0.3
2028/29	6.5	0.0	0.0	0.8	0.0	7.3	0.1	0.0	0.0	0.2	0.3
PSP 19-32											
2023/24	1.1	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	0.0	0.0
2024/25	1.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0
2025/26	1.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0
2026/27	1.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0
2027/28	1.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0
2028/29	1.1	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	0.0	0.0

Schedule 3

Columbia Gas of Maryland
2024 Design Day Forecast, 2024/25 - 2028/29
Firm Design Actual, Forecasted Firm Design Day Demand, and Forecasted Design Day Firm Demand Obligation
Quantities in MDth

Winter	1/ Firm Design Actual (1)	2/ Forecasted Firm Design Day (2)	3/ Adjustment for Standby and EBS (3)	Design Day Total Firm Demand Obligation (4) + (2) + (3)
04/05	48.6			
05/06	47.7			
06/07	49.2			
07/08	48.1			
08/09	49.7			
09/10	49.8			
10/11	48.3			
11/12	48.1			
12/13	49.6			
13/14	48.7			
14/15	51.9			
15/16	50.8			
16/17	51.0			
17/18	51.5			
18/19	51.5			
19/20	51.0			
20/21	50.1			
21/22	51.2			
22/23	51.2			
23/24	52.0			
24/25		52.2	2.1	54.3
25/26		52.6	2.1	54.7
26/27		52.9	2.1	55.0
27/28		53.2	2.1	55.3
28/29		53.5	2.1	55.6

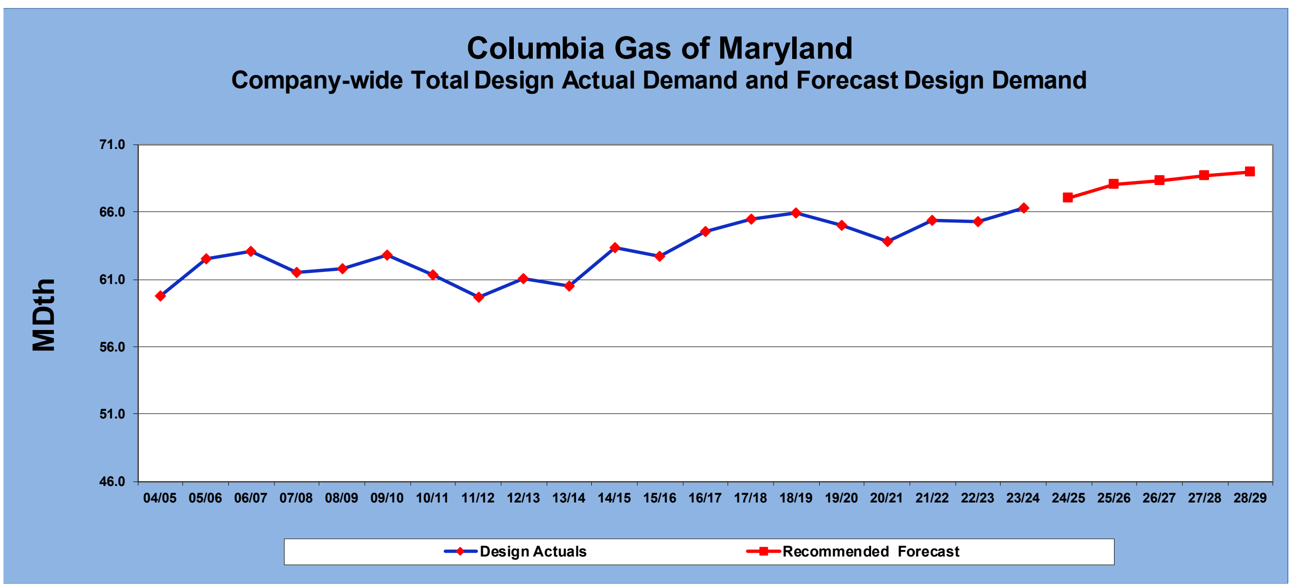


1/ Applicable heating season's regression equation applied to "Design Conditions" produces the annual "Design Actual" Demand.
2/ Recommended growth based on regression of the historical Design Actual against Number of Customers, Gas Cost, and Trend.
3/ Reflects adjustment for Standby Service Contract level and for Elective Balancing Service (EBS).

Schedule 4

Columbia Gas of Maryland
2024 Design Day Forecast, 2024/25 - 2028/29
Total Design Actual, Forecasted Total Design Day Demand, and Forecasted Design Day Total Demand Obligation
Quantities in MDth

	1/ Design Actuals	2/ Recommended Forecast
Winter	(1)	(2)
04/05	59.8	
05/06	62.5	
06/07	63.1	
07/08	61.6	
08/09	61.8	
09/10	62.8	
10/11	61.4	
11/12	59.7	
12/13	61.1	
13/14	60.5	
14/15	63.3	
15/16	62.7	
16/17	64.6	
17/18	65.5	
18/19	65.9	
19/20	65.0	
20/21	63.8	
21/22	65.4	
22/23	65.3	
23/24	66.3	
24/25		67.0
25/26		68.0
26/27		68.4
27/28		68.7
28/29		68.9



1/ Applicable heating season's regression equation applied to "Design Conditions" produces the annual "Design Actual" Demand.
2/ Recommended growth based on regression of the historical Design Actual against Number of Customers, Gas Cost, and Trend.

Schedule 5

Columbia Gas of Maryland
2024 Design Day Forecast, 2024/25 - 2028/29

Measuring Report For Non-Firm Customers
Based on January 2024 Demand
Quantities in DTh

	#PCID [(1)]	#PSID [(2)]	January Demand	%
COMMERCIAL:				
Daily [(3)]	17.00	17.00	50042.30	54.38%
Monthly	295.00	317.00	41985.30	45.62%
COM Sum	312.00	334.00	92027.60	100.00%
INDUSTRIAL:				
Daily [(3)]	10.00	10.00	79316.80	91.74%
Monthly	4.00	4.00	7144.00	8.26%
IND Sum	14.00	14.00	86460.80	100.00%
TOTALS:				
Daily [(3)]	27.00	27.00	129359.10	72.47%
Monthly	299.00	321.00	49129.30	27.53%
Grand Total	326.00	348.00	178488.40	100.00%

[(1)] PCID is an identification for a customer.

[(2)] PSID is an identification of a meter associated with a customer.

[(3)] Daily measurement includes chart read and electronically measured meters.

Schedule 6
Page 1 of 4

Columbia Gas of Maryland - PSP 19E

2024 Design Day Forecast, 2024/25 - 2028/29

Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In Dth

		Design Conditions	System Sales	Industrial Transpt. Non-Spec	Industrial Transpt. Special *	Commercial Transpt.
	2023/24 Design Actual		25,150	2,028	1,565	3,450
					95%	
			Regression Coefficients			
	Intercept		25,701.35	2,069.32	1,565.39	3,539.80
Variable 1 :	Current Temperature	**2**	(327.84)	(20.66)	0.00	(44.76)
Variable 2 :	Prior Day Temperature	**11**	(70.62)	0.00	0.00	0.00
Variable 3 :	Wind Speed	**12**	73.46	0.00	0.00	0.00
Variable 4 :	Day Type					
	Holiday		(636.84)	(271.62)	(1,342.57)	(63.41)
	Weekend		(493.69)	(183.50)	(1,080.58)	0.00
	Friday		0.00	(173.41)	0.00	0.00
	Saturday		0.00	(87.23)	0.00	(46.60)
	Sunday		0.00	0.00	0.00	0.00
	2024/25 Growth Factor		1.0037	1.0047	1.0047	1.1316
	2024/25 Design Demand		25,242	2,038	1,572	3,904
	Standby Service		593.00	---	---	---
	EBS		363.60	---	---	---
	Total R-Square		0.9730	0.8770	N/A	0.9810
	Durbin-Watson		1.3200	0.7650	N/A	1.1540
	Standard Error		546.2460	83.8967	N/A	51.4889
	Regression Type		1 Winter	1 Winter	1 Winter	1 Winter
	Number of Observations		89	91	90	91

* Special Industrial Transportation customers are small industrial customers w hose demand is different from larger customers.

Columbia Gas of Maryland - PSP 19-26

2024 Design Day Forecast, 2024/25 - 2028/29

Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In Dth

		Design Conditions	System Sales	Industrial Transpt. *	Commercial Transpt.
	2023/24 Design Actual		6,137	0	1,569
			Regression Coefficients		
	Intercept		5,629.42	---	1,469.50
Variable 1 :	Current Temperature	**-4**	(61.98)	---	(21.30)
Variable 2 :	Prior Day Temperature	**9**	(12.76)	---	0.00
Variable 3 :	Wind Speed	**8**	46.77	---	1.79
Variable 4 :	Day Type				
	Holiday		0.00	---	0.00
	Weekend		0.00	---	0.00
	Friday		0.00	---	0.00
	Saturday		0.00	---	0.00
	Sunday		0.00	---	0.00
	2024/25 Growth Factor		1.0093	---	0.9431
	2024/25 Design Demand		6,194	---	1,480
	Standby Service		39.00	---	---
	EBS		83.15	---	---
	R-Square		0.8970	---	0.9800
	Durbin-Watson		1.9260	---	0.7950
	Standard Error		190.3830	---	34.6930
	Regression Type		2 Winters	---	2 Winters
	Number of Observations		64	---	181

Columbia Gas of Maryland - PSP 19-27

2024 Design Day Forecast, 2024/25 - 2028/29

Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In Dth

		Design Conditions	System Sales	Industrial Transpt. Non-Spec	Industrial Transpt. Special *	Commercial Transpt.
	2023/24 Design Actual		18,025	1,910	0	3,110
					95%	
			Regression Coefficients			
	Intercept		16,959.02	1,797.76	0.00	3,044.41
Variable 1 :	Current Temperature	**-4**	(237.93)	(10.78)	0.00	(28.06)
Variable 2 :	Prior Day Temperature	**9**	(39.28)	0.00	0.00	(5.20)
Variable 3 :	Wind Speed	**8**	58.52	8.60	0.00	0.00
Variable 4 :	Day Type					
	Holiday		0.00	0.00	0.00	(77.66)
	Weekend		0.00	0.00	0.00	(52.43)
	Friday		0.00	0.00	0.00	0.00
	Saturday		0.00	0.00	0.00	0.00
	Sunday		0.00	0.00	0.00	0.00
	2024/25 Growth Factor		1.0027	1.0047	N/A	1.0114
	2024/25 Design Demand		18,074	1,919	0	3,145
	Standby Service		755.00	---	---	---
	EBS		239.55	---	---	---
	R-Square		0.9370	0.7650	N/A	0.9510
	Durbin-Watson		1.6160	1.0410	N/A	1.4250
	Standard Error		548.4910	51.9370	N/A	61.7890
	Regression Type		2 Winters	2 Winters	N/A	2 Winters
	Number of Observations		64	62	N/A	143

* Special Industrial Transportation customer w as Fibred Maryland, Inc. Its demand is expected to be 0 for w inter 24/25

Columbia Gas of Maryland - PSP 19-32

2024 Design Day Forecast, 2024/25 - 2028/29

Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In Dth

		Design Conditions	System Sales	Industrial Transpt.		Commercial Transpt.
				Non-Spec	Special *	
	2023/24 Design Actual		2,638	352	0	337
				95%		
			Regression Coefficients			
	Intercept		2,429.28	352.11	---	314.58
Variable 1 :	Current Temperature	**-4**	(33.33)	0.00	---	(3.93)
Variable 2 :	Prior Day Temperature	**9**	(4.55)	0.00	---	(0.26)
Variable 3 :	Wind Speed	**8**	14.55	0.00	---	1.17
Variable 4 :	Day Type					
	Holiday		0.00	(94.29)	---	0.00
	Weekend		0.00	(60.60)	---	0.00
	Friday		0.00	0.00	---	0.00
	Saturday		0.00	0.00	---	0.00
	Sunday		0.00	0.00	---	0.00
	2024/25 Growth Factor		1.0283	1.0057	---	1.1844
	2024/25 Design Demand		2,713	354	---	399
	Standby Service		6.00	---	---	---
	EBS		38.60	---	---	---
	R-Square		0.9700	N/A	---	0.9690
	Durbin-Watson		1.1260	N/A	---	1.2490
	Standard Error		55.1960	N/A	---	8.3079
	Regression Type		2 Winters	1 Winter	---	2 Winters
	Number of Observations		31	91	---	178

* Special Industrial Transportation customer w as Wood Product. Its demand is similar to other customers for w inter 23/24.

Schedule 7

Columbia Gas of Maryland

2024 Design Day Forecast, 2024/25 - 2028/29

Design Actual [1] Demand and Forecasted Design Day Demand

Quantities in Dth

	Firm Design Actual					Non-Firm Design Actual					Total
Historical Design Actuals	**PSP 19E**	**PSP 19-26**	**PSP 19-27**	**PSP 19-32**	**Sum**	**PSP 19E**	**PSP 19-26**	**PSP 19-27**	**PSP 19-32**	**Sum**	**Demand**
	(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**
04/05	19,432	6,890	19,999	2,313	48,633	6,635	1,725	2,414	400	11,175	59,808
05/06	19,003	6,158	20,280	2,225	47,666	7,898	2,183	4,243	534	14,858	62,524
06/07	20,159	6,632	19,968	2,397	49,156	7,808	2,015	3,682	469	13,974	63,130
07/08	20,057	6,565	19,106	2,349	48,077	7,222	2,068	3,713	484	13,487	61,563
08/09	21,253	6,466	18,921	3,057	49,696	5,822	2,004	4,115	209	12,150	61,846
09/10 with STS in Firm	21,558	6,615	18,948	2,722	49,843	6,795	2,121	3,849	227	12,991	62,834
10/11 with STS in Firm	20,155	6,780	18,739	2,634	48,308	6,959	2,126	3,698	264	13,048	61,356
11/12 with STS in Firm	20,609	6,573	18,418	2,511	48,112	5,682	2,128	3,488	274	11,572	59,684
12/13 with STS in Firm	21,118	6,416	19,325	2,719	49,578	6,215	1,875	3,071	324	11,485	61,063
13/14 with STS in Firm	21,520	6,116	18,751	2,346	48,733	5,977	1,988	3,469	321	11,756	60,489
14/15 with STS in Firm	23,409	6,647	18,990	2,813	51,859	5,830	1,951	3,341	346	11,468	63,327
15/16 with STS in Firm	23,231	6,408	18,617	2,569	50,825	5,460	1,499	4,330	581	11,870	62,695
16/17	23,363	6,437	18,675	2,541	51,016	6,069	1,609	5,393	486	13,557	64,573
17/18	23,263	6,647	19,081	2,556	51,547	6,458	1,546	5,306	610	13,920	65,467
18/19	23,598	6,795	18,699	2,360	51,452	6,817	1,507	5,503	636	14,463	65,915
19/20	23,259	6,947	18,562	2,227	50,995	6,518	1,407	5,336	726	13,987	64,982
20/21	23,311	6,723	17,606	2,465	50,105	6,512	1,171	5,294	750	13,727	63,832
21/22	24,085	6,771	17,835	2,533	51,224	7,081	1,228	5,178	667	14,154	65,378
22/23	24,338	6,305	17,985	2,612	51,240	6,870	1,656	4,884	686	14,096	65,336
23/24	25,150	6,137	18,025	2,638	51,950	7,043	1,569	5,020	689	14,321	66,271
Design Forecast Statistical Result											
Year Basis	20	6	11	5		10	20	6	16		
Multiple R^2	0.894	0.686	0.801	0.853		0.778	0.648	0.802	0.898		
Adjusted R^2	0.888	0.607	0.779	0.804		0.750	0.607	0.753	0.883		
Significance F	0.000	0.042	0.000	0.025		0.001	0.000	0.016	0.000		
Allocation of Firm Design Demand to PSP											
24/25	25,131	6,323	18,236	2,713	52,403	7,323	1,385	5,252	840	14,800	67,203
25/26	25,420	6,292	18,202	2,795	52,709	7,479	1,351	5,031	809	14,669	67,378
26/27	25,709	6,263	18,194	2,866	53,032	7,634	1,323	4,843	785	14,587	67,619
27/28	25,998	6,237	18,187	2,913	53,335	7,790	1,296	4,682	776	14,544	67,879
28/29	26,288	6,211	18,164	2,971	53,634	7,946	1,265	4,540	776	14,527	68,162
24/25 Smooth [2]											
24/25	25,285	6,214	18,113	2,717	52,329	7,261	1,460	5,025	749	14,495	66,824
25/26	25,420	6,292	18,202	2,795	52,709	7,479	1,351	5,031	809	14,669	67,378
26/27	25,709	6,263	18,194	2,866	53,032	7,634	1,323	4,843	785	14,587	67,619
27/28	25,998	6,237	18,187	2,913	53,335	7,790	1,296	4,682	776	14,544	67,879
28/29	26,288	6,211	18,164	2,971	53,634	7,946	1,265	4,540	776	14,527	68,162
Adjustments to Forecast											
Non-Firm Sales [3]											
24/25	(43)	(20)	(39)	(4)	(106)	43	20	39	4	106	
25/26	(43)	(20)	(39)	(4)	(106)	43	20	39	4	106	
26/27	(43)	(20)	(39)	(4)	(106)	43	20	39	4	106	
27/28	(43)	(20)	(39)	(4)	(106)	43	20	39	4	106	
28/29	(43)	(20)	(39)	(4)	(106)	43	20	39	4	106	
Economic Adjustments [4]											
24/25	0	0	0	0	0	210	0	0	0	210	
25/26	0	0	0	0	0	646	0	0	0	646	
26/27	0	0	0	0	0	737	0	0	0	737	
27/28	0	0	0	0	0	781	0	0	0	781	
28/29	0	0	0	0	0	781	0	0	0	781	
Forecast prior to Standby and EBS											
24/25	25,242	6,194	18,074	2,713	52,223	7,514	1,480	5,064	753	14,811	67,035
25/26	25,377	6,272	18,163	2,791	52,603	8,167	1,371	5,070	813	15,421	68,024
26/27	25,666	6,243	18,155	2,862	52,926	8,414	1,343	4,882	789	15,429	68,356
27/28	25,955	6,217	18,148	2,909	53,229	8,614	1,316	4,721	780	15,431	68,660
28/29	26,245	6,191	18,125	2,967	53,528	8,770	1,285	4,579	780	15,415	68,943
Standby Contract Level											
24/25	593	39	755	6	1,393	0	0	0	0	0	
25/26	593	39	755	6	1,393	0	0	0	0	0	
26/27	593	39	755	6	1,393	0	0	0	0	0	
27/28	593	39	755	6	1,393	0	0	0	0	0	
28/29	593	39	755	6	1,393	0	0	0	0	0	
EBS Contract Level											
24/25	364	83	240	39	725	0	0	0	0	0	
25/26	364	83	240	39	725	0	0	0	0	0	
26/27	364	83	240	39	725	0	0	0	0	0	
27/28	364	83	240	39	725	0	0	0	0	0	
28/29	364	83	240	39	725	0	0	0	0	0	
Adjusted Forecast											
24/25	26,199	6,316	19,069	2,757	54,341	7,514	1,480	5,064	753	14,811	69,152
25/26	26,334	6,394	19,157	2,836	54,721	8,167	1,371	5,070	813	15,421	70,141
26/27	26,623	6,366	19,150	2,906	55,044	8,414	1,343	4,882	789	15,429	70,474
27/28	26,912	6,339	19,143	2,953	55,347	8,614	1,316	4,721	780	15,431	70,778
28/29	27,201	6,314	19,120	3,012	55,646	8,770	1,285	4,579	780	15,415	71,061

[1] The Design Actual is an estimate of w hat the peak day demand w ould equate to if design conditions had occurred during the applicable w inter.

[2] To compensate for economic conditions w inter 2024/25 design demands may have been adjusted to reflect an average betw een the 2023/24 Design Actual and 2025/26 forecast design.

[3] Non-firm sales demand historically is reflected in the firm design actuals. To correctly reflect this demand an adjustment has been made decreasing firm and increasing non-firm design day demand.

[4] Economic Adjustment reflects the results of current and projected demand of large customers provided

Schedule 8

Columbia Gas Of Maryland

2024 Design Day Forecast, 2024/25 - 2028/29

2024/25 Design Day Requirements by Rate Schedule
Volume in MDth/Day

	Total Demand			Firm Demand			Non-Firm Demand			Additional Firm	Total Firm
	Tariff	Trans	Total Throughput	Tariff	Trans	Total Throughput	Tariff	Trans	Total Throughput	Obligation (1)	Obligation
Residential											
RS	**32.8**	**0.0**	**32.8**	**32.8**	**0.0**	**32.8**	**0.0**	**0.0**	**0.0**	**0.0**	**32.8**
Commercial											
GS-IS-TS1	12.9	0.0	12.9	12.9	0.0	12.9	0.0	0.0	0.0	0.0	12.9
GS-IS-TS2	6.0	0.0	6.0	6.0	0.0	6.0	0.0	0.0	0.0	0.0	6.0
ISL GS-IS-TS2	0.1	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.0
SS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4
EBS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
STS- GS-IS-TS1	0.0	1.6	1.6	0.0	0.0	0.0	0.0	1.6	1.6	0.0	0.0
TS- 990	0.0	2.5	2.5	0.0	0.0	0.0	0.0	2.5	2.5	0.0	0.0
TS- 995	0.0	4.8	4.8	0.0	0.0	0.0	0.0	4.7	4.7	0.0	0.0
Total Commercial	**19.0**	**8.9**	**27.9**	**18.9**	**0.0**	**18.9**	**0.1**	**8.8**	**8.9**	**1.5**	**20.4**
Industrial											
GS-IS-TS1	0.1	0.0	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.1
GS-IS-TS2	0.2	0.0	0.2	0.2	0.0	0.2	0.0	0.0	0.0	0.0	0.2
ISL GS-IS-TS2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EBS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6
STS- GS-IS-TS1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TS- 990	0.0	5.0	5.0	0.0	0.0	0.0	0.0	5.0	5.0	0.0	0.0
TS- 995	0.0	0.9	0.9	0.0	0.0	0.0	0.0	0.9	0.9	0.0	0.0
Total Industrial	**0.3**	**5.9**	**6.2**	**0.3**	**0.0**	**0.3**	**0.0**	**5.9**	**5.9**	**0.6**	**0.9**
Other	**0.1**	**0.0**	**0.1**	**0.1**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**
2024/25 Design Day	**52.2**	**14.8**	**67.0**	**52.1**	**0.0**	**52.1**	**0.1**	**14.7**	**14.8**	**2.1**	**54.3**

(1) Standby and Elective Balancing Service Quantities

Schedule 9

Columbia Gas of Maryland
2024 Design Day Forecast, 2024/25 - 2028/29

Historical Maximum Coincident Three Day Peak Day
Units are in Dth/Day

Winter Season	2022/23 [1]			2023/24 [1]		
	Peak Day				**Peak Day**	
Day of Week	Fri	Sat	Sun	Mon	Tue	Wed
Date	Dec. 23	Dec. 24	Dec. 25	Jan. 15	Jan. 16	Jan. 17
Avg Temp	4° F	12° F	18° F	23° F	16° F	20° F
Requirements [2]						
Residential	26,482	26,384	22,023	20,000	23,599	23,066
Commercial	24,443	24,354	20,328	18,461	21,785	21,292
Industrial	4,536	4,052	3,986	3,926	4,389	4,412
Other	0	0	0	0	0	0
Total Retail and Transportation:	**55,461**	**54,790**	**46,337**	**42,387**	**49,773**	**48,770**
Wholesale:	0	0	0	0	0	0
Company Use:	26	26	26	31	31	31
Unaccounted For:	113	113	113	112	112	112
Total Requirements:	**55,599**	**54,928**	**46,475**	**42,530**	**49,916**	**48,913**
Supply [3]						
Columbia Gas Transmission Corp.	55,599	54,928	46,475	42,530	49,916	48,913
Hagerstown Propane	0	0	0	0	0	0
Other	0	0	0	0	0	0
Total Supply:	**55,599**	**54,928**	**46,475**	**42,530**	**49,916**	**48,913**

Winter Season	2020/21 [1]			2021/22 [1]		
		Peak Day			**Peak Day**	
Day of Week	Wed	Thurs	Fri	Thurs	Fri	Sat
Date	Jan. 27	Jan. 28	Jan. 29	Jan. 20	Jan. 21	Jan. 22
Avg Temp	30° F	24° F	23° F	21° F	13° F	23° F
Requirements [2]						
Residential	17,917	21,984	21,785	21,657	25,263	21,842
Commercial	15,262	18,727	18,557	18,449	21,520	18,606
Industrial	4,588	4,565	4,430	4,412	4,481	3,939
Other	0	0	0	0	0	0
Total Retail and Transportation:	**37,767**	**45,276**	**44,772**	**44,518**	**51,264**	**44,387**
Wholesale:	0	0	0	0	0	0
Company Use:	50	50	50	30	30	30
Unaccounted For:	112	112	112	112	112	112
Total Requirements:	**37,929**	**45,438**	**44,934**	**44,660**	**51,406**	**44,529**
Supply [3]						
Columbia Gas Transmission Corp.	37,929	45,438	44,934	44,660	51,406	44,529
Hagerstown Propane	0	0	0	0	0	0
Other	0	0	0	0	0	0
Total Supply:	**37,929**	**45,438**	**44,934**	**44,660**	**51,406**	**44,529**

[1] Daily throughput based on the time of analysis and does not reflect any subsequent prior period adjustments.
[2] Total actual throughput; breakdown by category/class is an estimate.

Schedule 10

Columbia Gas of Maryland
2024 Design Day Forecast, 2024/25 - 2028/29

Design and Monthly Maximum Conditions With Corresponding Demand
Contract Year 2024-2025
Demand Units are MDth

	Design	Months											
	Peak	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
	Design Assumes Occurrence On Weekday												
Maximum													
Design Conditions													
Temperatures ºF													
Current Day [(1)]	-1	20	8	1	6	18	31	43	53	61	56	47	36
Prior Day [(2)]	10	26	15	11	14	24	36	48	58			50	40
Wind Speed (Mph) [(2)]	10	7	7	9	9	9	9						
Design Demand													
Firm [(3)]	52.2	33.3	45.0	50.6	46.9	36.1	23.4	10.7	2.8	2.7	2.4	5.2	16.6
Non-Firm	14.8	11.3	13.6	14.5	13.9	11.6	9.6	5.8	5.6	3.9	5.2	6.6	8.2
Total	67.0	44.7	58.6	65.1	60.8	47.7	33.0	16.5	8.4	6.5	7.6	11.8	24.8
Day Type Adjustments													
Holiday													
Firm [(3)]	(0.6)	(1.2)	(0.6)	(0.6)	(0.6)	0.0	0.0	0.0	0.0	(0.4)	(0.3)	0.0	0.0
Non-Firm	(1.8)	(1.3)	(1.8)	(1.8)	(1.8)	(1.5)	(2.0)	0.0	(1.1)	(1.0)	(0.6)	(1.3)	(1.3)
Total	(2.5)	(2.5)	(2.5)	(2.5)	(2.5)	(1.5)	(2.0)	0.0	(1.1)	(1.4)	(0.9)	(1.3)	(1.3)
Weekend													
Firm [(3)]	(0.5)	(1.2)	(0.5)	(0.5)	(0.5)	0.0	0.0	0.0	0.0	(0.3)	(0.3)	0.0	0.0
Non-Firm	(1.4)	(1.3)	(1.4)	(1.4)	(1.4)	(1.5)	(1.3)	0.0	(1.1)	(0.6)	(0.6)	(1.3)	(1.3)
Total	(1.9)	(2.5)	(1.9)	(1.9)	(1.9)	(1.5)	(1.3)	0.0	(1.1)	(0.9)	(0.9)	(1.3)	(1.3)
Standby	1.4												
EBS	0.7												

(1) Design Peak Current Day Temperature is based on a 1-in-10 Gumbel Distribution risk level. The Design Monthly Maximum Temperatures is based on a 1-in-10 Normal Distribution risk level.

(2) Design Prior Day Temperature not applicable during July and August; Design Wind Speed not applicable May through October

(3) Excludes Standby and EBS quantities.

Max Day Regressions Based on the Following:

December through February use the design equation applied to the month's design conditions. All other months' days for regression analyses are based on the most recent three year occurrence of days within the month when average daily temperatures are at or below the historical month average daily temperature that occurred during 1925 through 2015. Each months' regression equation is applied to the month's design conditions. Below each month's historical average daily temperature is provided.

Nov	Regression based on 3 years of November at temperatures below 45°F
Dec	Based on the sum of design market regressions (December thru February)
Jan	Based on the sum of design market regressions (December thru February)
Feb	Based on the sum of design market regressions (December thru February)
Mar	Regression based on 3 years of March at temperatures below 43°F.
Apr	Regression based on 3 years of April at temperatures below 55°F.
May	Regression based on 3 years of May at temperatures below 64°F.
Jun	Regression based on 3 years of June at temperatures below 75°F.
Jul	Regression based on 3 years of July at temperatures below 76°F.
Aug	Regression based on 3 years of August at temperatures below 76°F.
Sep	Regression based on 3 years of September at temperatures below 68°F.
Oct	Regression based on 3 years of October at temperatures below 56°F.

Schedule 11

Columbia Gas of Maryland
2024 Design Day Forecast, 2024/25 - 2028/29

Monthly Minimum Demand
Contract Year 2024-2025
Demand Units are MDth

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun [2]	Jul	Aug	Sep [3]	Oct
All Days												
Demand												
Firm [1]	8.3	14.2	17.1	13.9	7.3	3.0	0.9	0.9	2.0	2.0	2.0	2.7
Non-Firm	5.5	6.3	6.9	6.4	5.4	4.4	3.7	3.7	3.5	3.7	3.7	4.3
Total [1]	13.8	20.5	24.0	20.3	12.7	7.4	4.6	4.6	5.5	5.7	5.7	7.0
Weekdays												
Demand												
Firm [1]	8.1	15.0	17.6	13.1	7.2	2.7	1.1	1.1	2.1	2.1	2.2	2.6
Non-Firm	5.7	6.6	7.0	6.4	5.5	4.5	3.9	3.9	3.8	4.1	4.0	4.5
Total [1]	13.8	21.6	24.6	19.5	12.7	7.2	5.0	5.0	5.9	6.2	6.2	7.1
Weekends												
Demand												
Firm [1]	8.9	12.4	15.9	15.9	8.0	3.9	0.6	0.6	1.9	1.9	1.9	2.8
Non-Firm	5.2	5.5	6.5	6.6	4.9	4.0	3.1	3.1	3.2	3.2	3.2	4.1
Total [1]	14.1	17.9	22.4	22.5	12.9	7.9	3.7	3.7	5.1	5.1	5.1	6.9

Notes
(1) The Minimum Demand is calculated to be the demand having a 10% probability based on the actual daily demand experienced over the past five years.

(2) June's minimum demand calculated to be higher than shown for May. When this occurs May's values are used for June's minimum demand.

(3) September's minimum demand calculated to be lower than shown for August. When this occurs August's values are used for September's minimum demand.

APPENDIX

APPENDIX

DEVELOPMENT OF DESIGN CONDITIONS AND STATISTICAL ANALYSIS METHODS USED

I. Design Day Conditions

CMD's Design Day Conditions include Design Current Day Temperature, Design Prior Day Temperature, Design Current Day Wind Speed, with assumed occurrence on a weekday.

The Design Day Conditions for CMD are premised upon all available historical weather data ending with the winter 2014/15. The weights associated with the weather stations to generate the PSP Design Day Conditions are premised on December 2014 through February 2015 firm throughput. **Exhibit A** shows the Design Current Day Temperature, Design Prior Day Temperature, Design Wind Speed, the associated historical period, and the weights of the National Weather Service locations used to arrive at the Design Day Conditions for each PSP. The weather stations used for this determination are those located at Hagerstown, Maryland and at Morgantown, West Virginia. These weather stations are used because of their proximity to CMD's customers.

CMD's Design Current Day Temperature is that temperature having a 1 in 10 probability or a 10 percent risk level. That is, the probability is 1 in 10, or 10 percent that any given winter will have one or more days with an average daily temperature equal to or colder than the Design Current Day Temperature. CMD uses the Gumbel, or double exponential, distribution to calculate the probabilities. This skewed distribution fits the coldest day temperature data better than a normal distribution.

CMD has developed temperature probability distributions for four PSPs in Maryland. The PSPs correspond to geographically defined locations in Columbia Gas Transmission LLC's (TCO) FERC approved Tariff. The development of a Design Current Day Temperature for a PSP is a two-step process. First, for each weather station within the PSP, all available history is used to develop an associated design temperature. Next, for each PSP a weighted average design temperature is calculated based on the firm demand associated with each weather station. CMD's system wide Design Current Day Temperature is minus 1 degree Fahrenheit. The same method is used to develop Design Prior Day Temperature and Design Current Day Wind Speed by PSP and for CMD in total.

CMD's Design Prior Day Temperature is the sum of the Design Current Day Temperature plus the mean difference of Prior Day Temperature minus Current Day Temperature for all "Cold Days". A Cold Day is defined as a day as cold as or colder than the Design Current Day Temperature, plus 5 degrees Fahrenheit. For example, the Hagerstown weather station has a Design Current Day Temperature of 2 degrees Fahrenheit, so Cold Days for Hagerstown, by definition, have temperatures 7 degrees Fahrenheit or colder. The resultant average difference (Cold Days and their respective Prior Days) from this analysis is then added to the Design Current Day Temperature. The Hagerstown Design Prior Day Temperature is 11 degrees Fahrenheit. **Exhibit B** shows the historical temperature differences and calculation of Design Prior Day Temperature for the Hagerstown weather station. Each station's Design Prior Day Temperature and their station weighting are shown on **Exhibit A**.

Consistent with the Prior Day Design Temperature methodology, the approach of using an average of "Cold Days" is used to establish CMD's Design Current Day Wind Speed. However, because Wind Speed data has only been available since 1991/92, a Cold Day is defined as Design Current Day Temperature plus 15 degrees Fahrenheit for Wind Speed design. Using Cold Days defined as 15 degrees plus Design Current Day Temperature provides more observations per station. Again, the design is developed at the weather station level, and then weighted for the PSP and total company design. **Exhibit C** shows the data considered for determining the Design Current Day Wind Speed (the calculated average wind speed on cold days) for the Hagerstown weather station. The Design Current Day Wind Speed for each weather station is shown on **Exhibit A**.

Exhibit D shows the latest date within a winter season beyond which there is only a 10% probability of occurrence of a temperature equal to or colder than design. To determine this "Latest Day of Design Current Temperature", only the latest actual day of Design Current Day Temperature or colder occurring per winter heating season is considered in the distribution (red bars). Since there are few days in this analysis, a t-distribution was used to calculate the February 3rd date.

II. Regression Analysis and Criteria Considered

The statistic R^2 is "the estimated proportion of the variance of Y (the demand) that can be attributed to its linear regression on X (the collection of explanatory variables)". (Snedecor and Cochran, Statistical Methods, Seventh Edition, page 181.)

Note that R^2 for the Firm Demand component typically exceeds R^2 for the Industrial Demand component. The higher R^2 for Firm Demand indicates that the explanatory variables included in the model account for a high proportion of the day to day variation in demand. The lower R^2 for the industrial models indicates that variables not included in the models affect demand. For example, day-to-day production / operations, pricing of alternative fuels or customers' ability to use previously banked gas supplies may affect industrial demand.

In some PSPs the models have missing coefficients. A missing coefficient indicates that the associated variable does not affect demand with 95 percent confidence. In order to affect demand with 95 percent confidence, an explanatory variable must have an estimated regression coefficient, which is large compared to its standard error. In statistical terms, the probability of obtaining such a large estimated coefficient is less than 5 percent if the true coefficient is zero.

The day type variable includes both holiday and weekend demand impacts relative to weekdays. If weekend is found to be a valid explanatory variable, then holiday will have at least the same value as a weekend or may be greater (absolute value). In 2018, refinement of the new SPSS regression modeling tool facilitated a way to review and refine customers whose demand patterns are sporadic or are different from a typical demand load pattern. It was found through detailed analysis that certain industrial and commercial customers had demand patterns that were peculiar to the day of the week. For example, some companies have reduced consumption or shut down starting Friday through Sunday. In these instances, special coefficients are needed to describe these customers' consumption patterns. Therefore new variables for Friday, Saturday, and Sunday were introduced to the regression analysis for these customers. These variables are treated in a forecast calculation the same as a weekend or holiday coefficient. That is, the intercept is reduced by the amount of the coefficient for that particular day type. Since the Design Day Forecast assumes a weekday as the default design variable, these additional coefficients are for informational purposes only and do not affect the Design Day Demand Forecast. With this knowledge, however, the impact of these special variables can be approximated when looking at operational design. Additionally, with these special customers separated from the PSP forecast model, a more optimal design can be developed, since their design is held out from traditional designs but added in for the final design. There are other customers whose data is sporadic; when no demand pattern can be ascertained, the new SPSS software has the capability to calculate an average day for these customers based on a 95% confidence interval of the data.

III. Development of Monthly Maximum Conditions and Corresponding Demand

The Monthly Maximum Conditions are obtained using all available weather station temperature history which is then weighted to determine the company level design (see Section III, "Design Day Conditions"). Selection of the Monthly Maximum Demand Current Day Temperature is predicated on the actual average daily temperatures for a given month fitted to a normal distribution (vs. Gumbel distribution for Design Peak Day). The Monthly Maximum Demand Current Day Temperature is that temperature having a 10% risk level. That is, there is a 10 percent probability of a daily average temperature equal to or colder than the Monthly Maximum Day Current Temperature. As with Design Day Demand, Monthly Design Conditions are based on weather station weighting (see Section III). The Monthly Maximum Prior Day Temperature was developed using the same methodology for developing the Design Peak Day Prior Day Temperature. Prior Day Temperature is reflected in the months of September through June. Regression analysis has found that prior day temperature is not significant during the months of July and August.

For the months of November through March, Monthly Design Current Day Wind Speed reflects the average Wind Speed.

Regression analyses of daily firm and total demand were performed for each month using the past three years of history. Selection of a given month's days to be analyzed depended on the actual average gas-day temperature. Only days that had an average temperature within the monthly specific range were selected. The resulting regression coefficients were then applied to the Monthly Maximum Conditions to obtain the Monthly Maximum Demand.

The contracted Standby volume and EBS quantity are both shown on the schedule. This is a firm obligation for CMD when called upon by its customers.

IV. Winter Historical Information

Exhibit E reflects the winter historical information for the winters used in the regression analysis. For instance, this past winter, peak day occurred on Tuesday, January 16th, 2024. The temperature was 16ºF and total winter degree days was 3,441. Over the 75-year history, this past winter was 17% warmer than normal.

Exhibit A

Columbia Gas of Maryland
2024 Design Day Forecast, 2024/25 - 2028/29

Company and PSP Winter Monthly Design Day Conditions [1]

PSP Market Area	Pipeline Area	Location	Station Weighting	Company (Gumbel 1-in-10) Historical Period	Current Day Temp	Prior Day Temp [2]	Wind Speed [2]
25	Lancaster	Hagerstown, MD	100.0000	1925-2015	2	11	12
26	Bedford	Morgantown, WV	100.0000	1949-2015	-4	9	8
27	Cumberland	Morgantown, WV	100.0000	1949-2015	-4	9	8
32	Elkins	Morgantown, WV	100.0000	1949-2015	-4	9	8
CMD TOTAL		Hagerstown, MD	45.2009	1925-2015	2	11	12
		Morgantown, WV	54.7991	1949-2015	-4	9	8
			100.0000	Total Co	-1	10	10

(1) Using all available temperature data through March 2015 and weather station weights based on actual firm customer demand from December 2014 through February 2015.

(2) In the 2015 Study, Prior Day Temperature was developed using a 5 degree range for Cold Days; Wind Speed was developed using 15 degree range for Cold Days.

Exhibit B

Columbia Gas of Maryland
2024 Design Day Forecast, 2024/25 - 2028/29

Airport: HGR Weather Station: HAGERSTOWN, MD
Development of Weather Station Design Prior Day Temperature
Based on the 90 Heating Seasons 1925/1926 Through 2014/2015
For Variable: MID_MID_AVG_TMP with a Risk of 1 in 10

Cold Days Date	Cold Days Temp. In °F	Prior Day Temp. In °F	Prior Day - Cold Day
02/09/1934	5	22	17
02/28/1934	4	12	8
01/28/1935	4	19	15
01/23/1936	7	25	18
01/24/1936	6	7	1
01/25/1936	6	6	0
01/19/1940	7	16	9
01/08/1942	5	15	10
02/15/1943	7	17	10
01/31/1948	6	15	9
01/15/1957	6	18	12
01/17/1957	7	18	11
02/17/1958	4	15	11
12/23/1960	3	8	5
01/26/1961	3	8	5
02/02/1961	3	17	14
01/24/1963	6	22	16
01/29/1963	7	8	1
01/15/1965	7	20	13
01/29/1966	3	10	7
01/02/1968	2	12	10
01/11/1968	6	22	16
01/12/1968	2	6	4
01/08/1970	5	21	16
01/09/1970	4	5	1
01/16/1972	6	15	9
01/17/1977	4	14	10
02/18/1979	3	8	5
01/04/1981	6	23	17
01/12/1981	7	12	5
01/13/1981	7	7	0
01/10/1982	2	19	17
01/11/1982	4	2	-2
01/17/1982	-6	19	25
12/24/1983	6	22	16
12/25/1983	-3	6	9
12/26/1983	7	-3	-10
01/21/1984	7	12	5
01/22/1984	6	7	1
01/20/1985	3	24	21
01/21/1985	0	3	3
12/22/1989	7	13	6
01/15/1994	5	26	21
01/16/1994	6	5	-1
01/19/1994	-5	9	14
01/20/1994	3	-5	-8
01/21/1994	2	3	1
01/07/2014	7	27	20
01/22/2014	7	23	16
Average:	**4**	**13**	**9**

Design Day Temperature °F:	**2**
Range Temperature °F:	**5**
Maximum Cold Day Temperature °F:= 2+5	**7**
Design Prior Day Temperature °F: = 2+9	**11**

(1) For the purpose of determining the design Prior Day Temperature the Cold Day Temperature equals Design Day Temperature plus five degrees (2° + 5° = 7°).

(2) Days on which the observed average temperature was equal to or colder than 7°.

(3) The Design Prior Day Temperature is derived from the calculated average difference in temperatures on

Exhibit C

Columbia Gas of Maryland
2024 Design Day Forecast, 2024/25 - 2028/29

Airport: HGR Weather Station: HAGERSTOWN, MD.
Determination of Weather Station Design Wind Speed
Based on the 25 Heating Seasons 1991/1992 Through 2014/15
For Variable: MID_MID_WIND_SPEED with a Risk of 1 in 10
Note: History on Wind Speed Begins October 1991

Cold Day[(1)] Date[(2)]	Cold Days Temp. In °F	Wind Speed in MPH
01/19/1992	14	9
02/19/1993	15	7
01/10/1994	16	5
01/15/1994	5	19
01/16/1994	6	10
01/17/1994	17	10
01/18/1994	9	19
01/19/1994	-5	8
01/20/1994	3	2
01/21/1994	2	5
02/10/1994	16	9
01/05/1995	15	10
02/05/1995	14	27
02/06/1995	11	20
02/12/1995	15	16
12/10/1995	17	17
01/07/1996	15	15
01/11/1996	14	1
01/20/1996	17	3
02/03/1996	14	14
02/04/1996	8	14
02/05/1996	9	9
12/21/1996	17	5
01/17/1997	12	21
01/18/1997	12	17
01/19/1997	13	5
01/02/1999	17	8
01/05/1999	17	9
01/21/2000	17	21
01/22/2000	17	8
12/23/2000	15	6
01/18/2003	10	5
01/22/2003	14	11
01/23/2003	11	19
01/27/2003	13	12
02/16/2003	12	10
01/10/2004	10	8
01/16/2004	14	17
01/23/2004	14	12
01/24/2004	16	6
01/25/2004	10	3
01/26/2004	15	7
01/30/2004	16	15
01/31/2004	13	14
02/01/2004	17	3
12/20/2004	13	18
01/17/2005	17	21
01/18/2005	14	13
01/22/2005	16	8
01/23/2005	14	21
01/24/2005	17	10
01/27/2005	17	8
01/28/2005	16	4
12/14/2005	16	4
02/05/2007	9	20
02/06/2007	12	11
02/07/2007	17	11
02/08/2007	17	15
02/15/2007	14	16
01/20/2008	16	17
02/11/2008	17	11
12/22/2008	17	18
01/15/2009	17	13
01/16/2009	9	13
01/17/2009	13	9
02/05/2009	17	14
01/22/2011	15	2
01/22/2013	15	19
01/23/2013	16	10
01/25/2013	17	5
01/03/2014	15	14
01/07/2014	7	16
01/22/2014	7	12
01/23/2014	11	11
01/24/2014	12	10
01/28/2014	8	7
01/29/2014	13	10
02/12/2014	16	6
02/28/2014	15	4
03/03/2014	17	10
01/07/2015	17	21
01/08/2015	13	13
01/10/2015	16	10
02/15/2015	9	25
02/16/2015	9	7
02/19/2015	11	21
02/20/2015	10	11
02/24/2015	16	9
03/06/2015	14	5

Average Cold Day Wind Speed [(3)]	**12**
Design Day Temperature °F:	**2**
Range Temperature °F:	**15**
Maximum Wind Speed Cold Day Temperature °F:	**17**

(1) For the purpose of determining the Design Current Day Wind Speed the Cold Day Temperature equals Design Day Temperature plus fifteen degrees (2° + 15° = 17°).
(2) Days on which the observed average temperature was equal to or colder than 17°.

Exhibit D

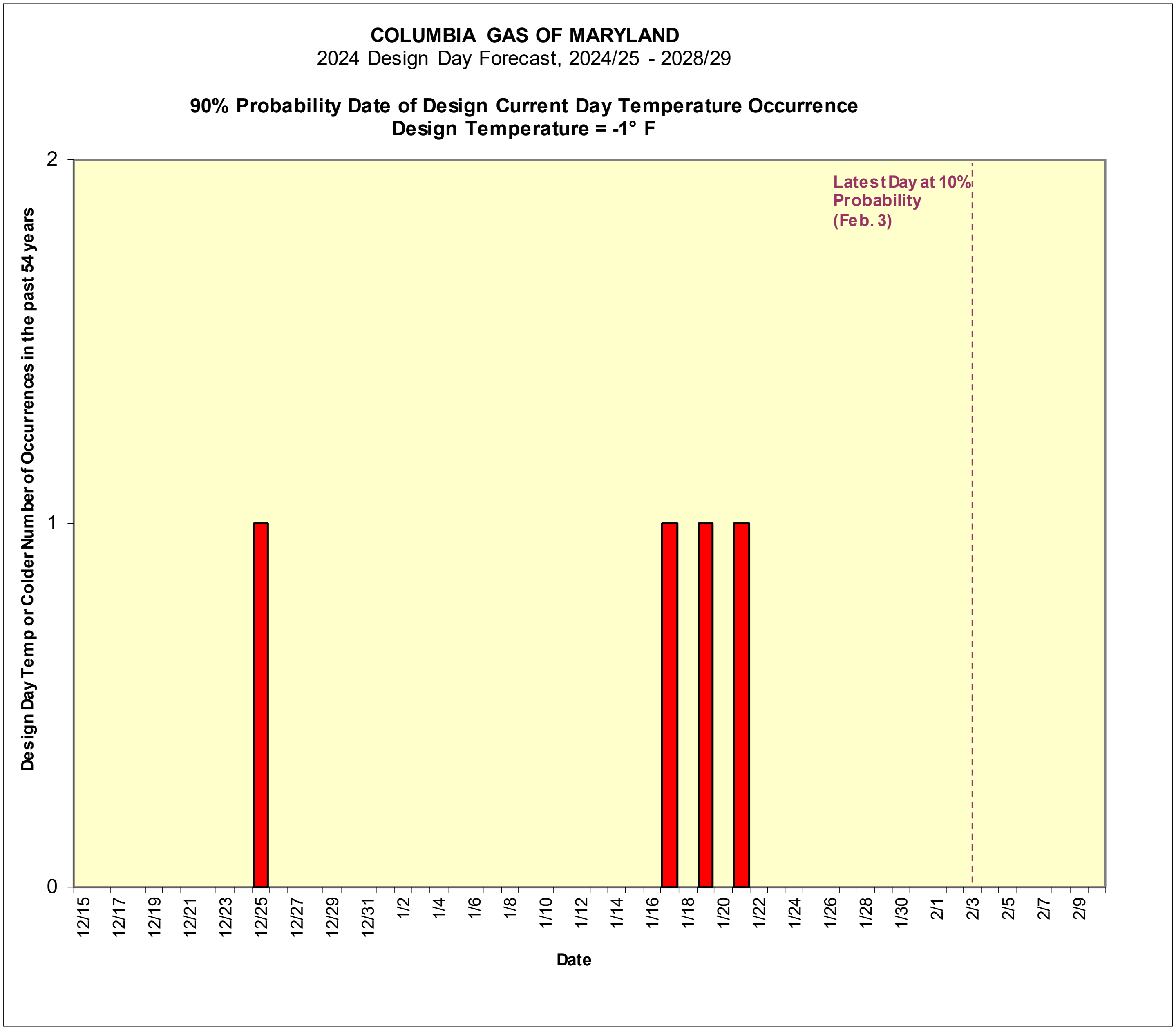

COLUMBIA GAS OF MARYLAND
2024 Design Day Forecast, 2024/25 - 2028/29
90% Probability Date of Design Current Day Temperature Occurrence
Design Temperature = -1° F
Latest Day at 10% Probability (Feb. 3)
Design Day Temp or Colder Number of Occurrences in the past 54 years
0
1
2
12/15
12/17
12/19
12/21
12/23
12/25
12/27
12/29
12/31
1/2
1/4
1/6
1/8
1/10
1/12
1/14
1/16
1/18
1/20
1/22
1/24
1/26
1/28
1/30
2/1
2/3
2/5
2/7
2/9
Date

Exhibit E

Columbia Gas of Maryland, Inc.
2024 Design Day Forecast, 2024/25 - 2028/29

Winter Historical Information

	Winter DDs @ 65°	% From 75 Year Average	Peak	Peak Day of Week	Dec. - Jan Days < 31° F
01/02	3,436	-17	3/4, 19° F	Monday	12
02/03	4,628	12	1/23, 12° F	Thursday	36
03/04	4,297	4	1/30, 12° F	Friday	38
04/05	4,082	-1	1/23, 11° F	Sunday	24
05/06	3,923	-5	12/13, 19° F	Tuesday	20
06/07	3,943	-5	2/5, 7° F	Monday	17
07/08	4,075	-1	1/20, 12° F	Sunday	20
08/09	4,200	2	1/16, 4° F	Friday	29
09/10	3,951	-4	1/2, 16° F	Saturday	26
10/11	4,429	7	12/14, 18° F	Tuesday	43
11/12	3,276	-21	1/3, 17° F	Tuesday	16
12/13	4,128	0	1/22, 12° F	Tuesday	11
13/14	4,669	13	1/7, 8° F	Tuesday	29
14/15	4,551	10	2/19, 5° F	Thursday	38
15/16	3,376	-18	1/18, 12° F	Monday	17
16/17	3,549	-14	12/15, 12° F	Thursday	14
17/18	4,169	1	1/5, 8° F	Friday	27
18/19	4,083	-1	1/30, 5° F	Wednesday	18
19/20	3,620	-12	12/18, 23° F	Wednesday	9
20/21	3,770	-9	1/28, 24° F	Thursday	13
21/22	3,781	-9	1/21, 13° F	Friday	27
22/23	3,473	-16	12/23, 4° F	Friday	10
23/24	3,441	-17	1/16, 16° F	Tuesday	10

Design Temp: -1° F (1 in 10 Risk)
DD Avg. 1949/50 - 2023/24: 4136
2023/24 Winter 17% Warmer than 75 year average
2023/24 Winter ranks 72nd coldest of 75 winters

Columbia Gas of Maryland, Inc.

Docket No. 9707, Phase II
Data Requests

Office of People's Counsel
Set 1

All of the data requests in this set pertain to Issue 1 which states "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." (Order No. 91791 at 7).

Question No. OPC 1-017:

Please refer to the discussion of projected demand, winter season degree-days, and the supply planning process in Special Master 1-001 Attachment B (SGSP, Executive Summary, pp. 5–6; Sections III.A–III.C, pp. 18–19 or pdf pp. 20–21).

(a) Please describe the methodology used to forecast annual gas consumption, including the historical period of gas consumption and weather data used, how historical consumption was weather-normalized, and all variables or drivers included in the forecast.

(b) Please also explain whether the annual gas demand forecast is developed using a statistical or econometric model (such as a regression model), and if so, please describe at a high level the model structure, including the dependent variable, key independent variables, and the manner in which weather and non-weather factors are represented.

Objection – Columbia objects to the request to "describe at a high level," as it is ambiguous, lacks specificity and fails to adequately describe the material or information sought. Without waiving the foregoing objection, Columbia provides the following response:

Response:

a) The methodology used to forecast customer counts and usage per customer (including a list of all independent variables) is described in OPC 1-020. The forecasted customer counts and forecasted usage per customer are then multiplied together to arrive at forecasted consumption.

The historical consumption is not weather normalized. Instead, actual usage per customer is the dependent variable for the regression model, and actual recorded heating degree days (HDDs) are the independent variable. Then, normal HDDs recorded on a basis of 20 years ending December 31, 2024 are used to forecast the forecast period, giving us a weather normalized forecast.

Finally, the starting month of all historical data is as follows (all models use historical data through December 2024): residential customer count (January 2015), residential usage per customer (January 2013), small commercial customer count (January 2015), small commercial usage per customer (January 2016), and small industrial volume (January 2020).

b) Annual gas demand is estimated by building econometric models for customer counts and usage per customer for residential and small commercial customer classes, and an econometric model for small industrial volumes. Large commercial and large industrial customer counts and usage per customer are forecasted by Columbia's Major Accounts group through one-on-one discussions with customers. Small industrial customer counts are forecasted to remain at historical levels.

Details regarding model structure and how weather factors are represented can be found in OPC 1-020.

Columbia Gas of Maryland, Inc.

Docket No. 9707, Phase II
Data Requests

Office of People's Counsel
Set 1

All of the data requests in this set pertain to Issue 1 which states "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." (Order No. 91791 at 7).

Question No. OPC 1-019:

Please refer to the discussion of strategic issues affecting future gas demand and projected demand assumptions in Special Master 1-001 Attachment B (SGSP, Chapter II, pp. 9–18; Chapter III, pp. 19–22). Please explain whether and how the Company considered the following when developing the annual gas use forecast:

(a) end-use efficiency improvements

(b) fuel switching and electrification (e.g., heat pumps)

(c) long-term temperature or climate trends

(d) state or local energy or decarbonization policies

(e) If any of these factors were not considered, please explain why.

Response:

a) This data is available in the Itron Statistically Adjusted End-Use spreadsheets described in the Direct Testimony of Michael Girata dated February 9, 2026, in Case No. 9707. While available as an independent variable, the end-use efficiency data was not used in the 2026-2030 SGSP due to strong forecast performance without their inclusion.

b) Not considered when developing the forecast.

c) A 20-year normalization period for Heating Degree Days (HDDs) is used to develop the normal HDDs for the forecast period. This allows Columbia Gas of Maryland to capture recent weather trends and incorporate the trends in the forecast.

d) Not considered when developing the forecast.

e) Items (b) and (d) were not explicitly considered when building the forecast as any historical measurable activity related to fuel switching/electrification or government policies would directly impact Columbia's recorded usage and therefore, would be carried into the forecast period at the same rate. As such, no adjustments are appropriate to remove impacts, if any, from the forecast period.

Columbia Gas of Maryland, Inc.

Docket No. 9707, Phase II
Data Requests

Office of People's Counsel
Set 1

All of the data requests in this set pertain to Issue 1 which states "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." (Order No. 91791 at 7).

Question No. OPC 1-020:

Please refer to the discussion of contract-year demand forecasts by customer class in Special Master 1-001 Attachment B (SGSP, Section III.C, p. 19 or pdf p. 21; Exhibit III.2, p. 23 or pdf p. 25). Please explain how projected firm customer counts and average annual usage per customer were estimated and incorporated into the annual gas demand forecast, and identify the data sources used for these projections.

Response:

Residential and small commercial customer counts are forecasted using regression modeling where the dependent variable is historical customer counts and the independent variables include household counts (residential) and real income per capita (small commercial). Additional variables to account for seasonality are included.

For residential and small commercial usage per customer, regression modeling is also used with historical usage per customer as the dependent variable, and independent variables including weather in the form of Heating Degree Days ("HDD") and monthly variables to account for seasonality.

For small industrial customers, customer count is held flat to historical levels, while usage is forecasted using a regression model. Total usage is the dependent variable, and independent variables include weather in the form of HDDs and monthly variables to account for seasonality.

For large commercial and large industrial customers, customer count and volumes are provided by Columbia Gas of Maryland's Major Accounts group. The forecasts are built using one-on-one discussions with customers to understand their operating plans for future months.

The forecasts described above are built at the customer-class level and are then allocated to firm and non-firm based on the historical relationship between the two categories.

All historical customer count and usage data is extracted from Columbia Gas of Maryland’s billing system. All economic data is provided by IHS Markit (a subsidiary of S&P Global). All weather data is provided by DTN, a third-party vendor that provides weather data from NOAA weather stations.

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

CASE NO. 9707 PHASE II

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
DIRECTED TO THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-3

Q. 1-1. Refer to the following statement on p. 6 of the Portfolio Plan: "As measured by the United States Weather Bureau at Reagan National Airport, there have been two Design Days within recent history: January 17, 1982, and January 19, 1994, and two near-design days in January 1994." P. 6.

(a) Please confirm that neither of these days are among the Top 25 days with the highest firm gas sendout used in the Design Day regression analysis (as described on pp. 5–8). If confirmed, please explain potential reasons why firm gas sendout on these two design days was not as high as on the Top 25 Sendout Days.

(b) Please provide the following information for January 17, 1982 and January 19, 1994, as well as any associated calculations with formulas intact in machine-readable electronic format (Excel or CSV):

(i) Total daily firm sendout

(ii) Hourly temperature

(iii) Daily average temperature

(iv) Average wind speed

WASHINGTON GAS'S OBJECTION

A. Washington Gas objects to (b) in its entirety, as it asks for materials to be provided in a certain format. To the extent Washington Gas answers this question, Washington Gas will provide information in the format in which it is kept in the regular course of business. Furthermore, Washington Gas objects to (b)(ii), (b)(iii), and (b)(iv), as they request information that is publicly available.

WASHINGTON GAS'S RESPONSE **February 27, 2026**

A. As per the agreement between OPC and Washington Gas, Washington Gas hereby provides the following response:

(a) The Company confirms that January 17, 1982 and January 19, 1994 are not in the current Top 25 Day list. The load on these two design days was not as high as on the Top 25 Sendout Days likely because these two design days occurred over 40 years ago, when firm loads on the Company's system were smaller than the days that comprise the Top 25 Sendout Days (of which the oldest is January 23, 2005). Over the past four decades, the Company's system has experienced growth in both the number of customers and total sendout, resulting in higher firm usage on more recent high-demand days. Thus, even though the weather was colder on the two design days, the overall firm usage was lower than on later days that did not experience weather that was as cold.

WASHINGTON GAS'S RESPONSE **March 3, 2026**

A. (a) [Response provided 2/27/2026]

(b) (i) Daily firm sendout on January 19, 1994 is provided in 9707.OPC-1-3bi.Attachment CONFIDENTIAL.wk3. The Company is not aware of records of daily sendout on January 17, 1982. See also the response to subpart (a).

(ii) thru (iv) Historical weather data can be obtained from the national weather service at the following website: https://www.weather.gov/wrh/Climate?wfo=lwx

SPONSOR: Lisa Gillison
Director, Energy Acquisition

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

CASE NO. 9707 PHASE II

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
DIRECTED TO THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-10

Q. Refer to the Company's discussion of historical demand, weather normalization, and temperature assumptions on pp. 10–13 of the Portfolio Plan.

(a) Please identify the historical period of gas consumption and weather data used to develop the annual gas use forecast.

(b) Please describe how historical consumption was weather-normalized.

(c) Please explain whether and how observed or projected climate-related temperature trends were considered.

WASHINGTON GAS' RESPONSE **February 27, 2026**

A. (a) The historical period used for each rate class varies by rate class. Please also see the Company's attachments to OPC DR 1-15.

(b) Historical consumption was not weather-normalized to produce the normal weather forecast. Instead, the usage per customer by class forecast equations were developed based on actual usage and actual HDD, and were used to forecast normal weather usage by substituting in normal weather HDD.

(c) Any climate-related temperature trends are captured in the calculation of the normal HDD through annually updating the regression of temperature data used to calculate normal HDD to incorporate the most recent weather observations.

SPONSOR: Lisa Gillison
Director, Energy Acquisition

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

CASE NO. 9707 PHASE II

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
DIRECTED TO THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-1

Q. Refer to WGL's response to OPC-1-1 and the following statement: "The Company's design day temperature is an engineering judgment, based on the assumed temperature at which all temperature-sensitive appliances are operating at full capacity." Please also refer to the Company's response to OPC-1-4 and the following statement: "Wind speed does not impact the Design Day demand estimate."

(a) Please explain what WGL means by "engineering judgement" in this context.

(b) Please explain in detail how WGL derived the Design Day temperature "at which all temperature-sensitive appliances are operating at full capacity."

(c) Please explain the purpose of including wind speed in the Design Day analysis, given WGL's statement that wind speed does not impact the Design Day demand estimate.

WASHINGTON GAS' RESPONSE **April 10, 2026**

A. (a) Engineering judgment is the application of professional knowledge, experience, and logical reasoning to make informed decisions when clear rules, data, or formulas are unavailable or incomplete. It is often described as the "art" within the science of engineering. While calculations provide a mathematical foundation, engineering judgment evaluates whether those results are reasonable and applicable in real-world conditions.

(b) As previously stated in the Company's response to OPC-1-1, WGL applied professional knowledge, experience, and logical reasoning to develop an estimate of the Design Day temperature, as no clear-cut rules, data, or formulas exist to precisely determine this value.

(c) The design day forecast methodology is based on the historical Top 25 sendout days, which correspond to some of the coldest weather conditions on record. These days inherently include the wind speeds that prevailed at the time, and those wind conditions are reflected in the observed sendout levels. Accordingly, the design day methodology accepts the wind speeds associated with these Top 25 sendout days as given and does not adjust wind speeds upward or downward from the conditions that occurred on those historical peak sendout days.

SPONSOR: Lisa Gillison
Director, Energy Acquisition

Maryland Building Decarbonization Study

Final Report

October 20, 2021

Tory Clark, Director
Dan Aas, Director
Charles Li, Managing Consultant
John de Villier, Consultant
Michaela Levine, Associate
Jared Landsman, Senior Consultant

Energy+Environmental Economics

Content

Summary of Updates

+ E3 has made the following updates to the analysis based on feedback from the Buildings Subgroup and MWG participants

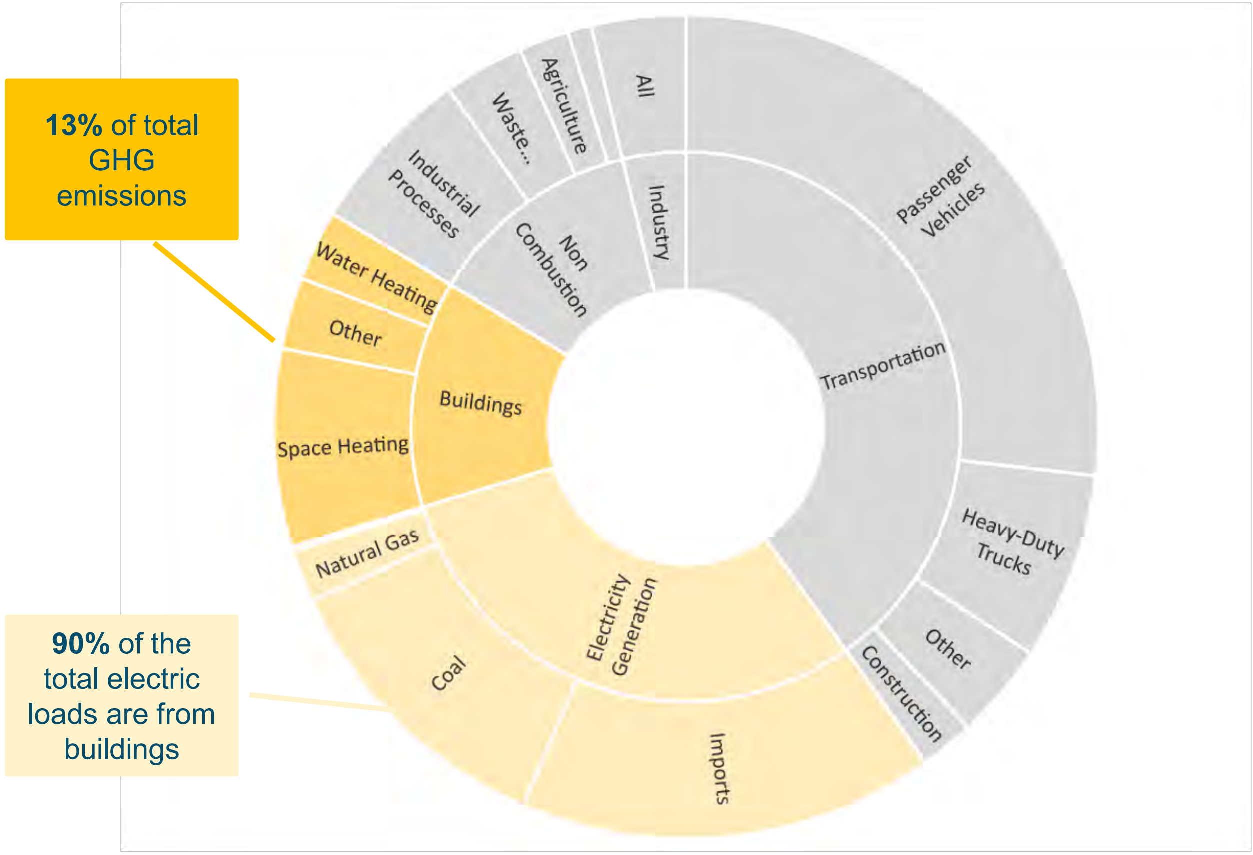
- Updated the **electric efficiency assumptions** in the High Decarb Methane scenario assuming **extension of EMPOWER**
- Halved the **gas revenue requirement growth rate after 2035**, to be consistent with GGRA assumption that **STRIDE** will complete by then
- Adjusted the **optimistic RNG scenario** to reflect **competition from liquid fuels**
- Estimated GHG emissions from **methane leakage** for each scenario
- Corrected **an error in the electric system cost** estimate
- Adjusted the **equipment cost** for the **High Electrification with Improved System Configuration** case to reflect larger tonnage for heat pumps
- Integrated **climate impact** into the analysis
- Conducted analysis for the **MWG Policy Scenario**
- Conducted **a sensitivity with no retrofit shell improvement measures** across all scenarios

Background and Scenario Design

Project objective: a Maryland-specific pathway to achieve deep decarbonization of building end-uses by mid-century

+ **Based on the most recent Maryland GHG Inventory for 2017, building direct-use emissions account for 13% of economywide GHG emissions in Maryland**
  - 80% of direct building emissions are from space heating and water heating
+ **90% of the statewide electric load are from buildings, which contribute to upstream emissions in electricity generation**
  - Currently, electricity generation accounts for 30% of total GHG emissions, but will decrease as clean and renewable energy becomes a larger share
+ **Key questions of this project:**
  - What are the potential pathways to achieve deep decarbonization of Maryland's building stock by mid-century?
  - What are the costs and benefits of each pathway from a total system cost perspective, as well as impacts on consumers?

MD 2017 Gross GHG Emissions by Sector and Subsector



This study investigates opportunities for building decarbonization through 3 scenarios

- **E3 and MDE held a 4-hour workshop with the Buildings Ad-hoc Group, where we received feedback and input from stakeholders on scenario design that informed the selection of the following scenarios**

Reference	High Electrification	Electrification with Fuel Backup	High Decarbonized Methane
+ Same as the Reference scenario in the GGRA analysis reflecting current policies + Buildings keep using existing devices with no electrification and little efficiency improvement + Building energy demand grows at 0.6%/yr, same as EIA's projected annual growth rate of Maryland households	+ Almost all buildings switch to ASHPs and GSHPs. Heating is supplied by electricity throughout the entire year + High efficiency through deep building retrofits	+ Existing buildings keep using fuels for heating and are supplied with a heat pump combined with existing furnace/boiler that serves as back up in the coldest hours of the year + All-electric for new construction	+ Buildings keep using fuels for heating while fossil fuels are gradually replaced by low-carbon renewable fuels. Some features: • RNG supplied by biomethane and synthetic natural gas • 7% hydrogen blend • High efficiency through deep building retrofits

3 steps to analyze the impacts of building decarbonization scenarios

3 selected scenarios

Scenario Specification
Development of decarbonization scenarios, heating equipment costs and renewable fuel supply curve

Assess Energy System Impacts and Cost Implications
Analysis of incremental equipment costs, electric system costs and fuel costs.

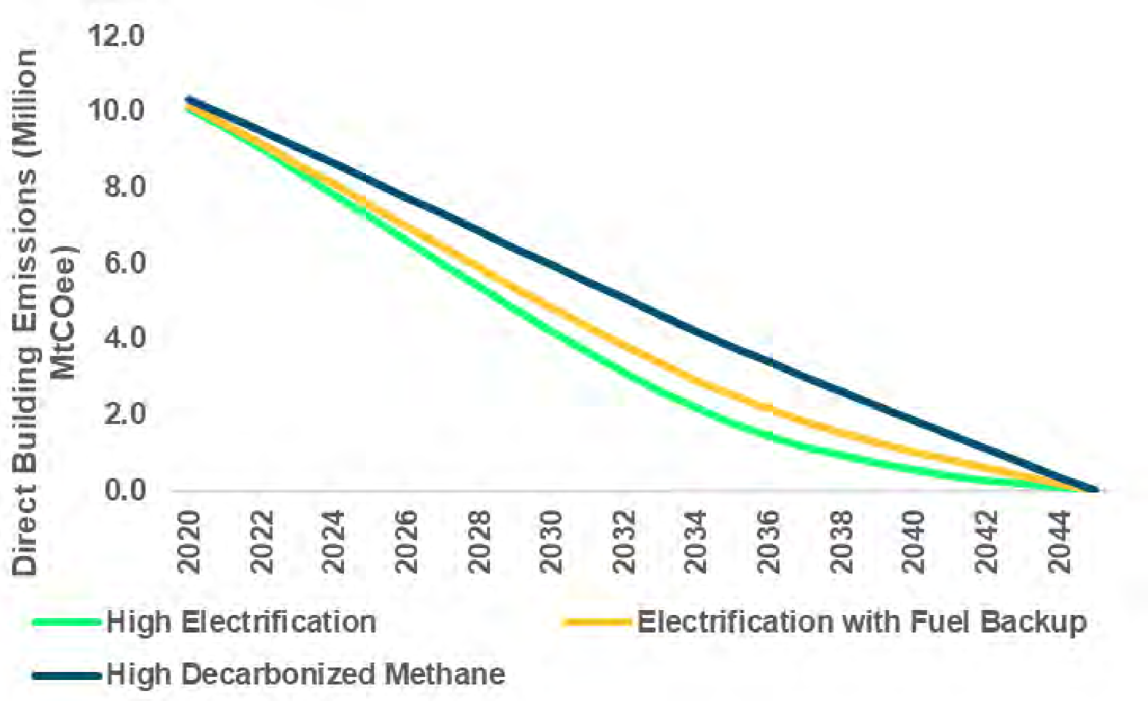
Electric and Gas Rate Impacts
Development of electric and gas revenue requirement models to estimate rate impacts

Overview of technical and economic implications

GHG Emissions and Energy Consumption

All scenarios achieve zero direct building emissions by 2045

Direct building GHG emissions trajectory (MMtCO2e per year)

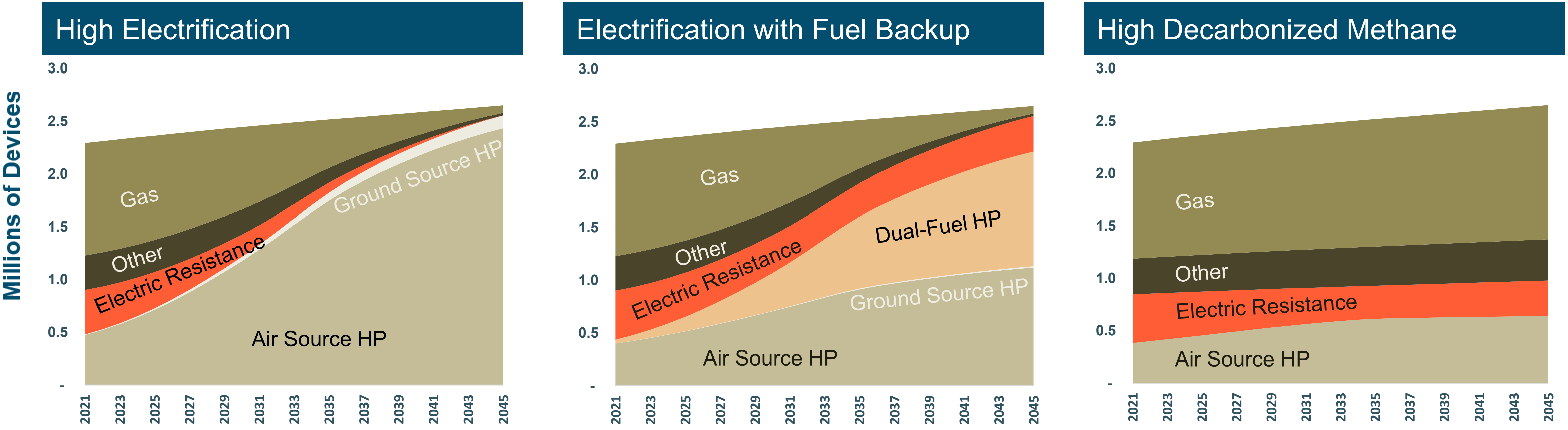


- Cumulative direct emissions and methane leakage from 2021 to 2045 add to 90 MMT CO2e in the High Electrification scenario, 103 MMT CO2e in the Electrification with Fuel Backup scenario, and 117 MMT CO2e in the High Decarbonized Methane scenario.
- CAVEAT: Cumulative emissions are subject to assumptions about timing of key policies and measures that drive the decarbonization trajectory; any comparisons among the scenarios should use caution.

+ **All scenarios achieve zero direct building emissions by 2045 through electrification, efficiency improvement and use of low-carbon fuels**
  - This is consistent with the MCCC-recommended economy-wide target of carbon neutrality by 2045
+ **Methane leakage from in-state gas pipelines may still contribute to indirect emissions**
  - Current emissions from methane leakage associated with building gas consumption are ~0.5 MMT CO2e
  - By 2045, methane leakage from each scenario is shown below, assuming that in-state pipeline leakage rate will decrease by 58% by 2045 relative to 2017 consistent with assumptions from the 2030 GGRA Plan
    - High Electrification - 0.02 MMT CO2e
    - Electrification with Fuel Backup - 0.09 MMT CO2e
    - High Decarbonized Methane - 0.19 MMT CO2e

Space heating end-uses are mostly electrified by 2045 in the two electrification scenarios

- **Heat pumps become the major space heating equipment in the High Electrification scenario**
- **Dual-fuel heat pumps are added to most retrofit buildings in the Electrification with Fuel Backup scenario, pairing with existing fuel-based systems**
- **Electric resistance currently accounts for about 20% of space heating devices**



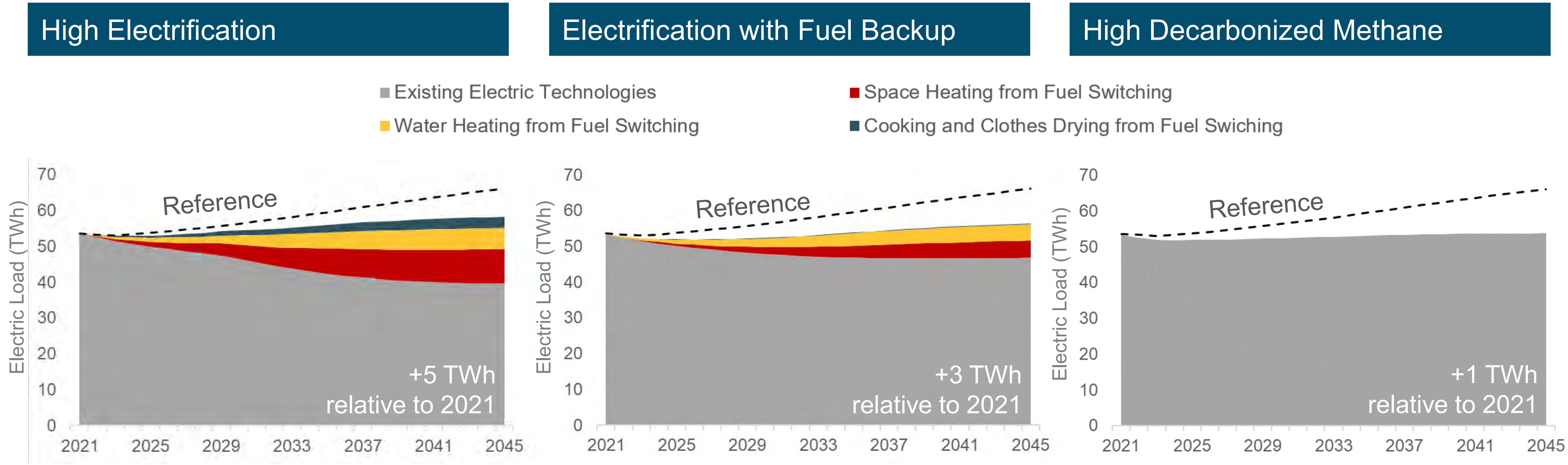
* "Other" space heating devices mainly include fuel oil and LPG-based furnaces and boilers

* Consistent with the 2030 GGRA Plan, the Electrification with Fuel Backup and High Decarbonized Methane scenarios assume continuation of EMPOWER program after 2023

* E3 is working with MDE to evaluate the impact of geothermal heating and cooling carve-out requirement in the RPS on GSHP adoption assumptions across the scenarios

Electricity demand in all scenarios are lower than Reference due to energy efficiency gains

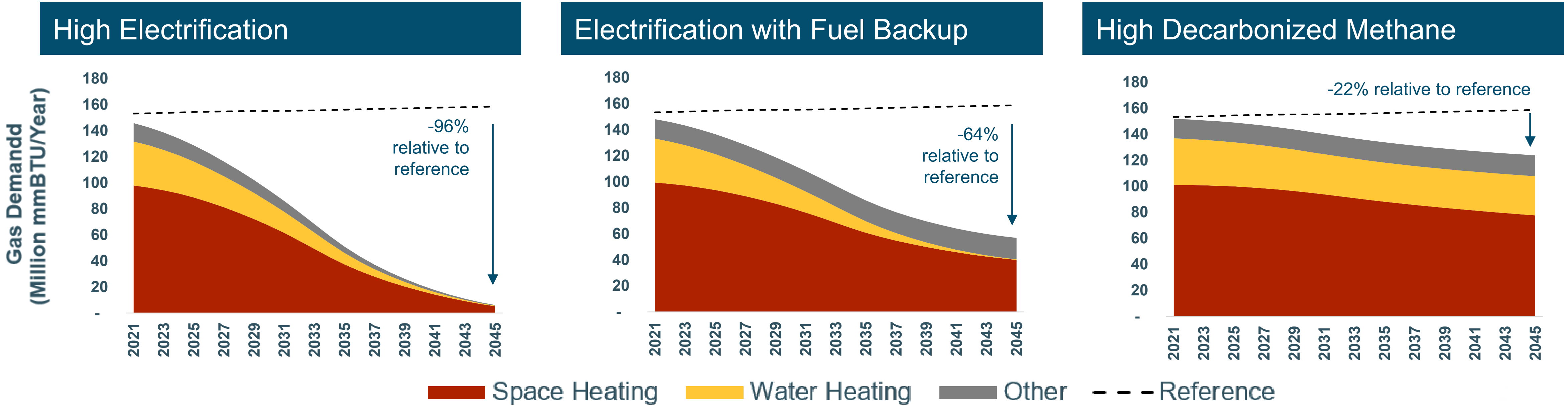
+ **Electricity demand increases in all scenarios due to growth in households**
  - **High Electrification** scenario has the highest load growth among the three scenarios due to new space heating, water heating and other loads as a result of fuel switching
+ **Compared to Reference, all scenarios have lower electricity demand due to energy efficiency gains**
  - **High Electrification** scenario also has the largest reduction in existing loads due to higher levels of efficiency from building shell improvement and efficient electric device adoption



Natural gas demand declines in all scenarios due to energy efficiency gains and fuel switching offsetting growth

+ Natural gas use in buildings is expected to decline in all scenarios due to energy efficiency gains offsetting growth in households, and this decline is accelerated in scenarios with significant building electrification

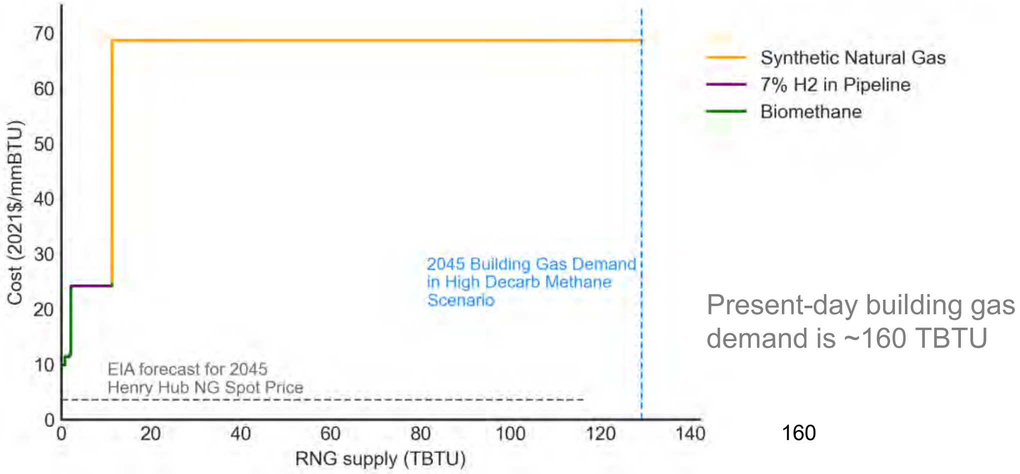
- **High Electrification** reduces gas demand by 96% by 2045 due to aggressive electrification of all building end-uses
- **Electrification with Fuel Backup scenario** has lower reduction in gas demand by 2045 at 62%, as most customers adopt dual-fuel heat pumps that use gas with gas as a backup heating source during coldest hours of the year
- **High Decarbonized Methane** scenario results in a 19% reduction in gas demand by 2045 due to efficient gas appliance adoption and building shell improvements



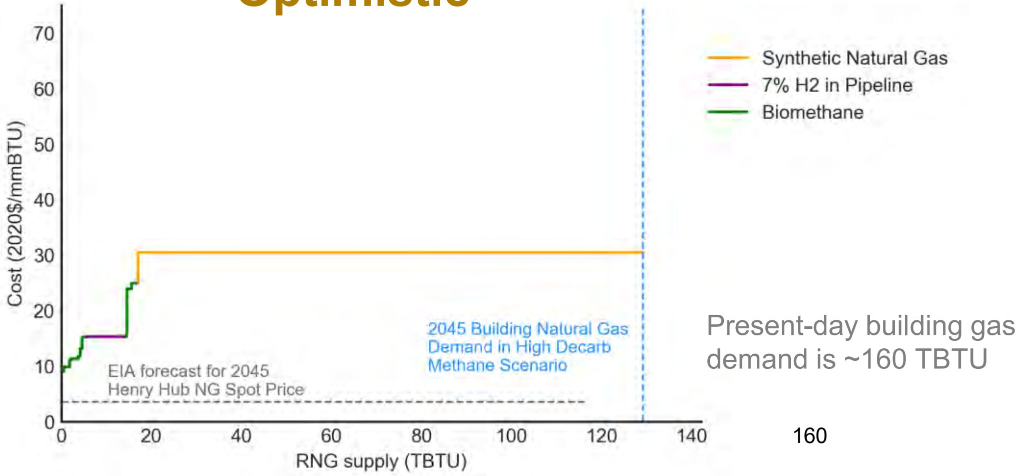
The E3 Biofuels Module models two bookends for RNG Supply

- **RNG Supply Curve assumptions are developed using E3 biofuels optimization module, which determines the most cost-effective way to convert biomass into biofuel across all sectors.**
- **Conservative and Optimistic scenarios modeled here represent two bookends for the supply of RNG towards 2045 to reflect uncertainties with technology commercialization and scalability**
  - **Conservative** scenario has heavy reliance on Synthetic Natural Gas (SNG); it assumes
    - MD only gets access in-state biomass feedstocks
    - Conservative projection of learning rate for electrolyzers, which is the main component of H2 production
  - **Optimistic** scenario has moderate reliance on SNG; it assumes
    - MD gets access to its population weighted-share of national feedstocks
    - Optimistic projection of learning rate for electrolyzers
  - Both scenarios assume that ALL cellulosic feedstocks would be more cost-effectively used to produce liquid fuels - such as renewable diesel or jet fuel (due to higher prices and carbon intensities for these fuels)

Conservative



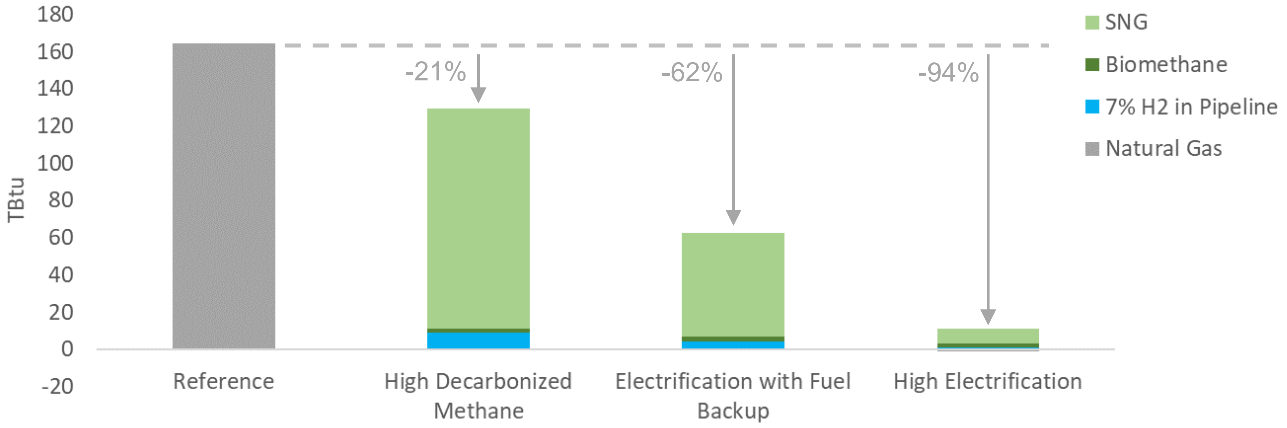
Optimistic



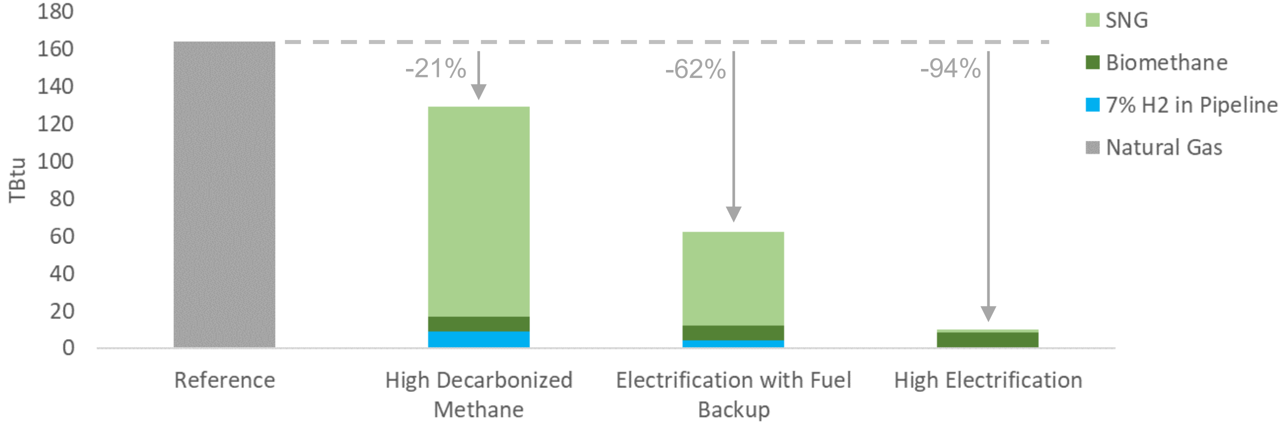
Sources & assumptions: Biomass supply assumptions are developed from the 2016 Billion Ton Report (DOE, 2016), with supplemental landfill gas assumptions from the Renewable Sources of Natural Gas report (American Gas Foundation, 2019). The conservative scenario assumes SNG is produced with CO_2 from Direct Air Capture (DAC), the optimistic scenario assumes SNG is produced using waste bio-CO2 from biofuels. The 7% hydrogen blend is as a percentage of energy content. More background on cost assumptions are included in the Appendix.

Gas composition transitions to RNG

Gas commodity blend in 2045 (Conservative)



Gas commodity blend in 2045 (Optimistic)

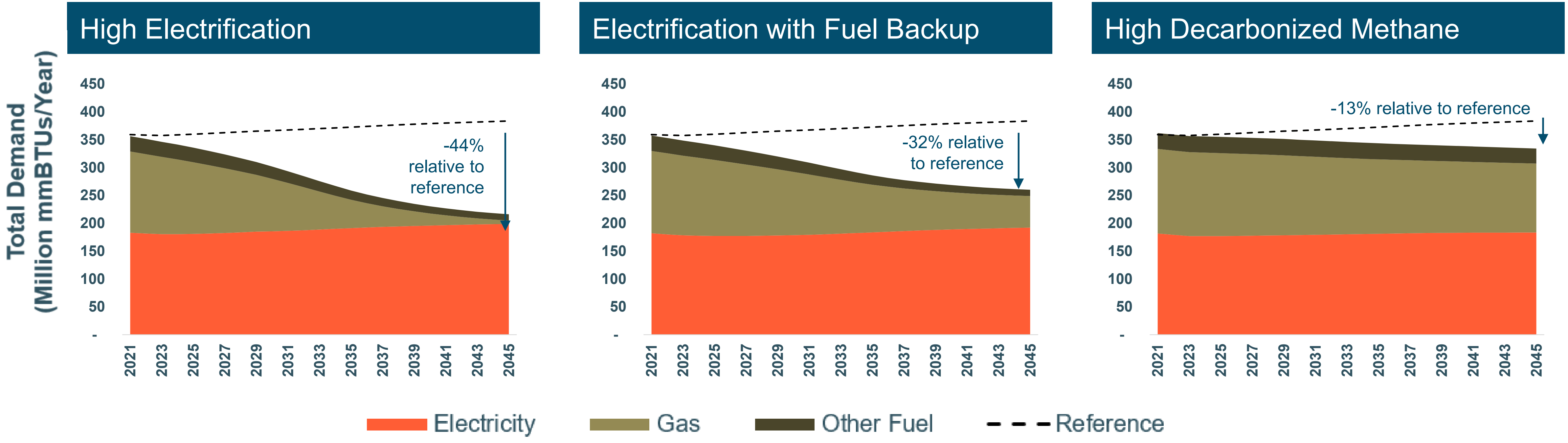


- **By 2045, all building scenarios have 100% blend of RNG in the remaining gas demand**
  - This helps all scenarios reach zero direct building emissions target by 2045
  - Hydrogen blend in pipeline is assumed in all scenarios where it makes economic sense, up to 7% in energy content (20% in volume) which is the maximum current natural gas pipelines can take without significant modification
- **In a conservative RNG scenario where biomass supply is limited, SNG is the main source of low-carbon gas in all scenarios**
- **In an optimistic RNG scenario, SNG is still needed across all scenarios due to the limit in biomass supply**

All scenarios reduce total energy demand

+ Overall energy demand decreases through 2045 in all scenarios

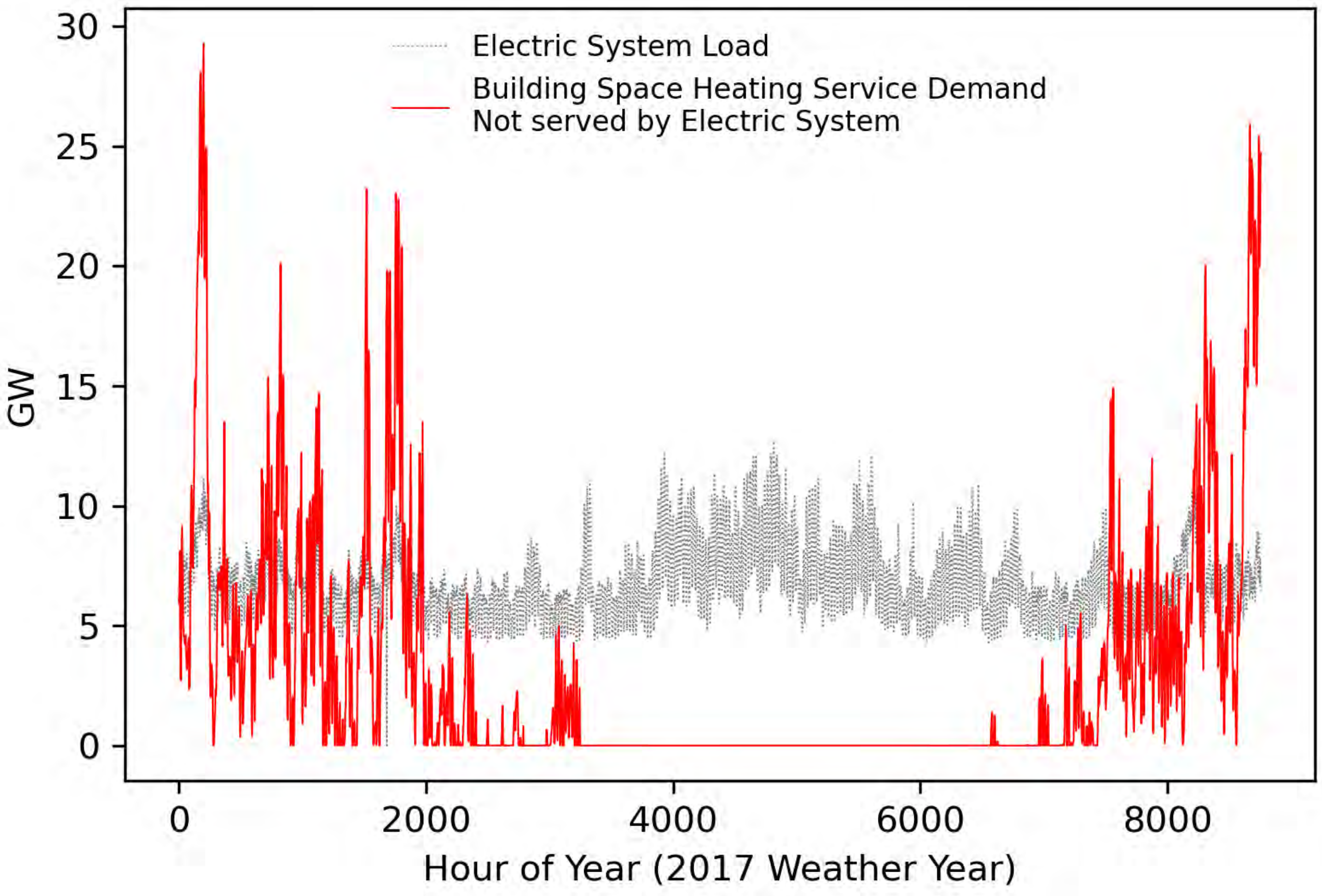
- Deep electrification almost eliminates gas demand by 2045 under the High Electrification Scenario
- Gas demand decreases ~62% in the fuel backup scenario due to adoption of dual-fuel heat pumps, while overall energy demand falls 32%
- Efficiency gains from building shell improvements and efficient appliance adoption reduce overall demand by 13% in the High Decarbonized Methane Scenario



* Year 2021 will not perfectly match reference because electrification/efficiency adoption begins in model year 2017

Electric system peak impacts

Maryland's current electric system peaks in summer



Electric system summer peak in 2017 was approximate 12.6 GW and the winter peak was approximately 11.1 GW.

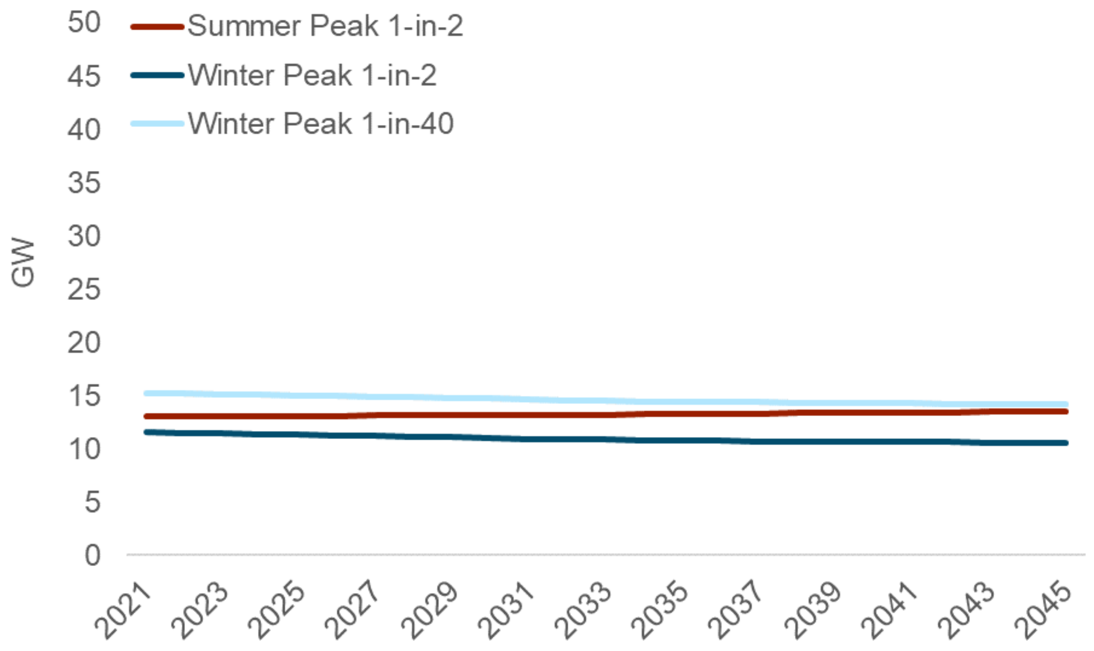
+ **Currently, Maryland's electricity system experiences peak load in summer months**
  - Load peaks at around 13 GW, mainly as a result of residential and commercial air conditioning
+ **Maryland's *building heat load,* however, currently mainly supplied by gas, shows a large peak in winter as a result of the state's cold winter climate**
  - Building heat loads represent *service demand* of both space and water heating, i.e. total heating load if all supplied by electric resistance
  - Moving the thermal load from gas to electric will result in a significant increase in electric peak in winter

Sources & assumptions: Building thermal load is based on PATHWAYS total space and water heating service. Shape of the thermal load is calculated using E3's RESHAPE model. Note that the chart shows imputed system load for November and December as a result of data gaps.

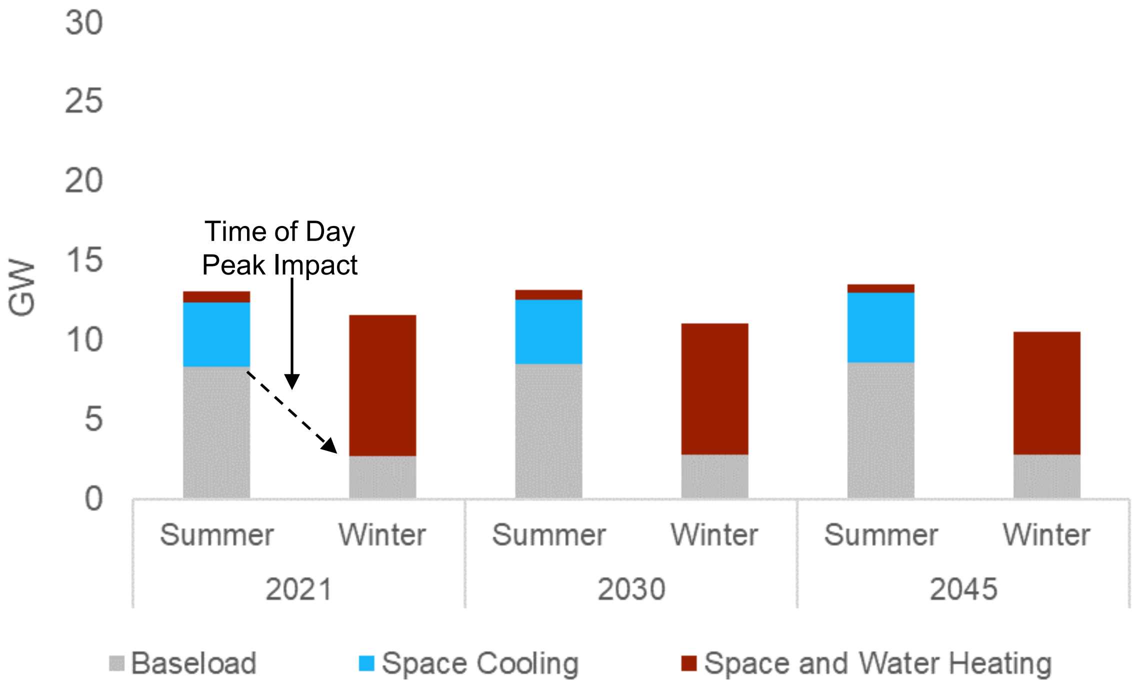
Maryland is expected to have little peak load growth in the High Decarbonized Methane scenario

+ **In the High Decarbonized Methane scenario, the small peak load growth is due to growth of households and economy.**

Peak Load Projection 2021-2050
High Decarbonized Methane



Contribution to 1-in-2 System Peak by Sector
High Decarbonized Methane

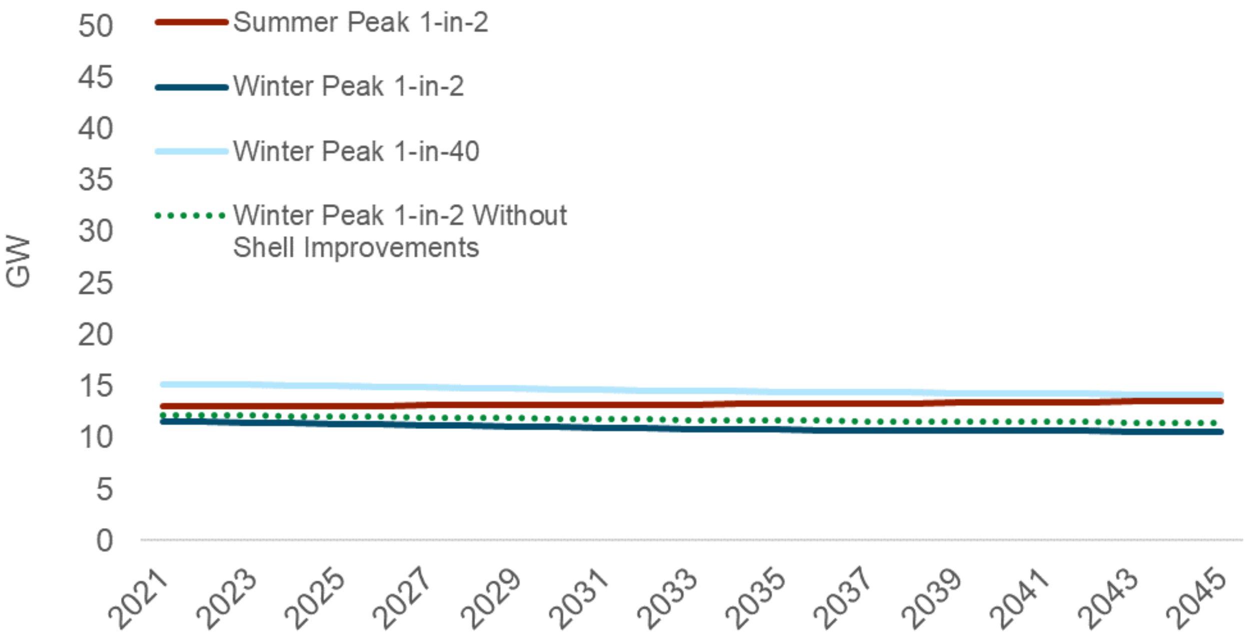


Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

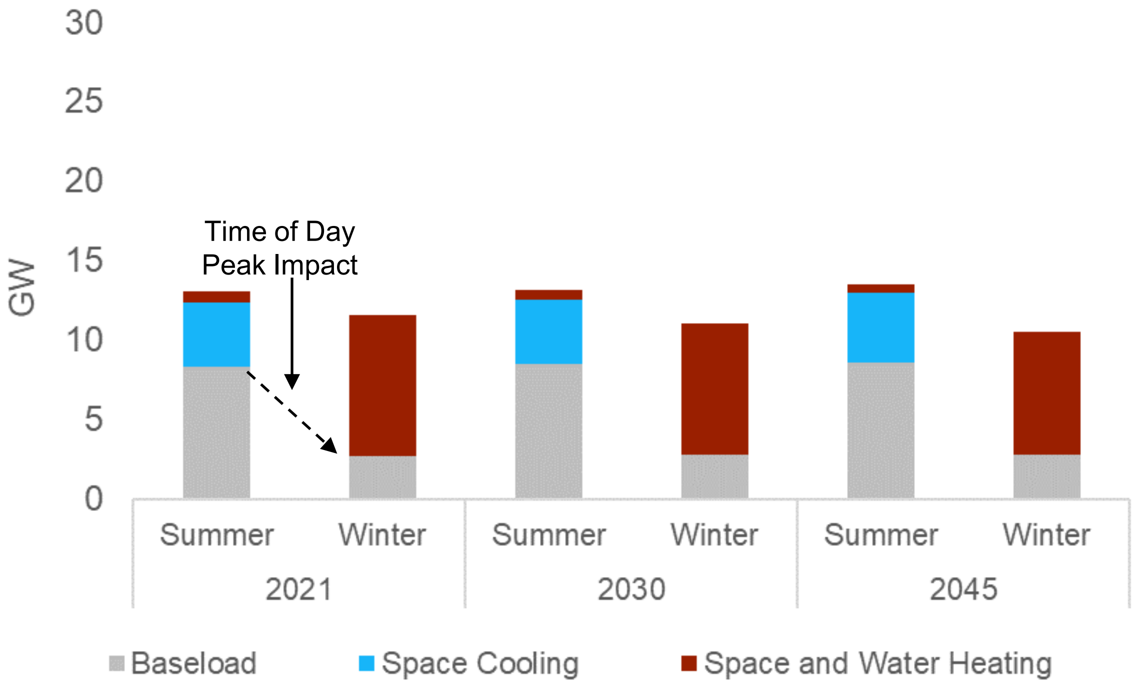
Maryland is expected to have little peak load growth in the High Decarbonized Methane scenario

+ **In the High Decarbonized Methane scenario, the small peak load growth is due to growth of households and economy.**

Peak Load Projection 2021-2050
High Decarbonized Methane



Contribution to 1-in-2 System Peak by Sector
High Decarbonized Methane

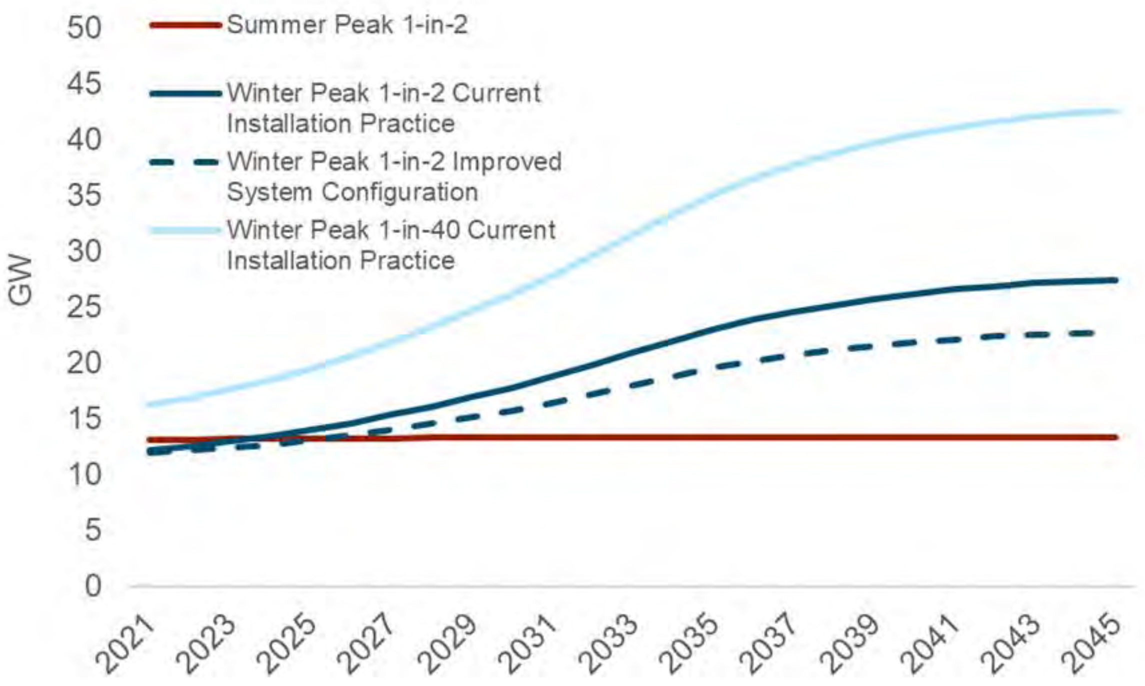


Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

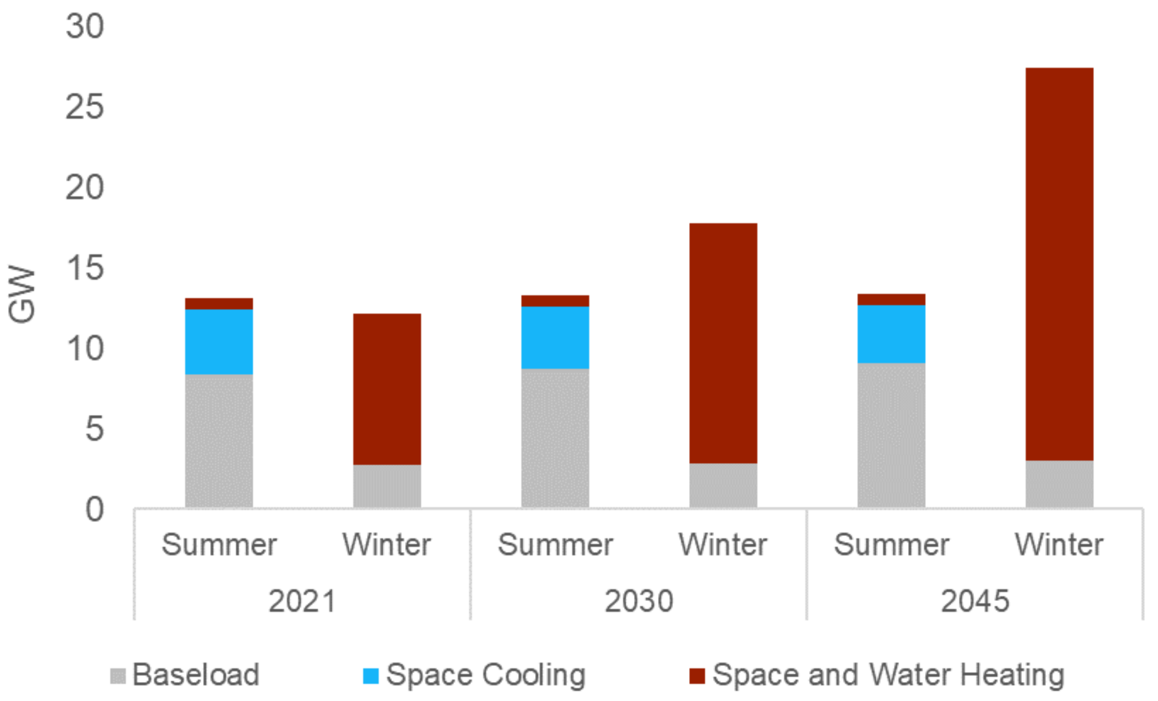
Winter peak load is expected to grow by 15 GW by 2045 in the High Electrification scenario

+ **In the High Electrification scenario, Maryland's electricity system is expected to become winter peaking in the near future, and will more than double the current system peak by 2045**
  - Switching to heat pumps from electric resistance heating, which is currently used in about 25% of Maryland households, has a much smaller impact on peak heating load than on annual total heating loads

Peak Load Projection 2021-2045
High Electrification



Contribution to 1-in-2 System Peak by Sector
High Electrification – Current Installation Practice

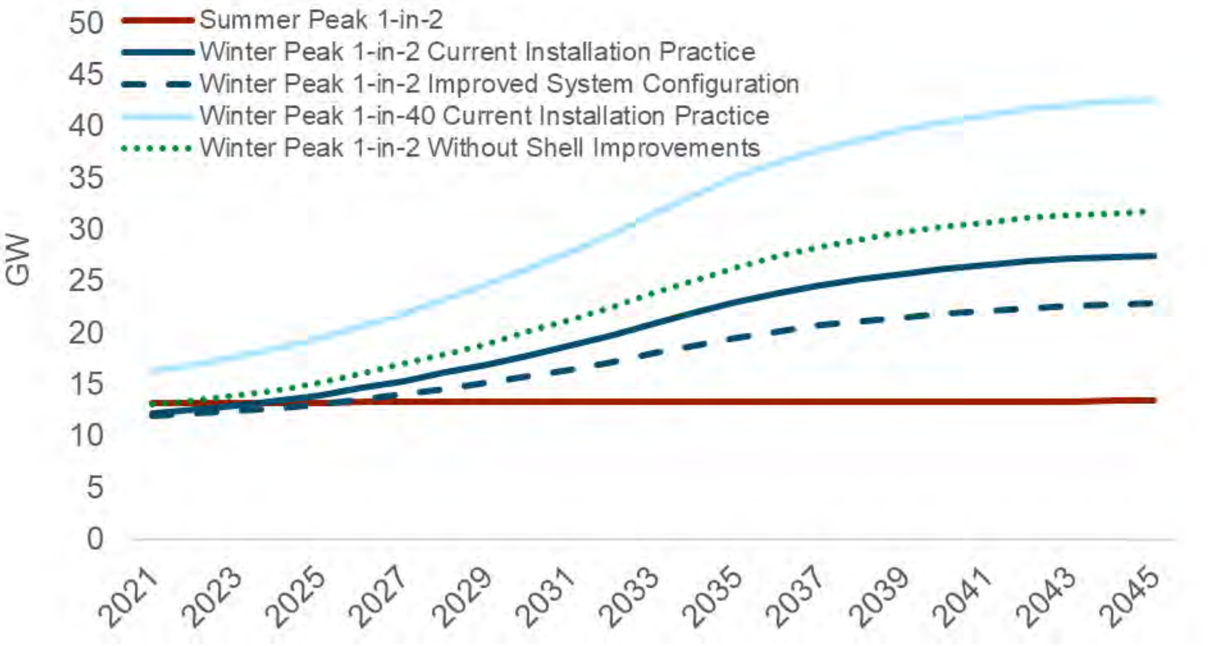


Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

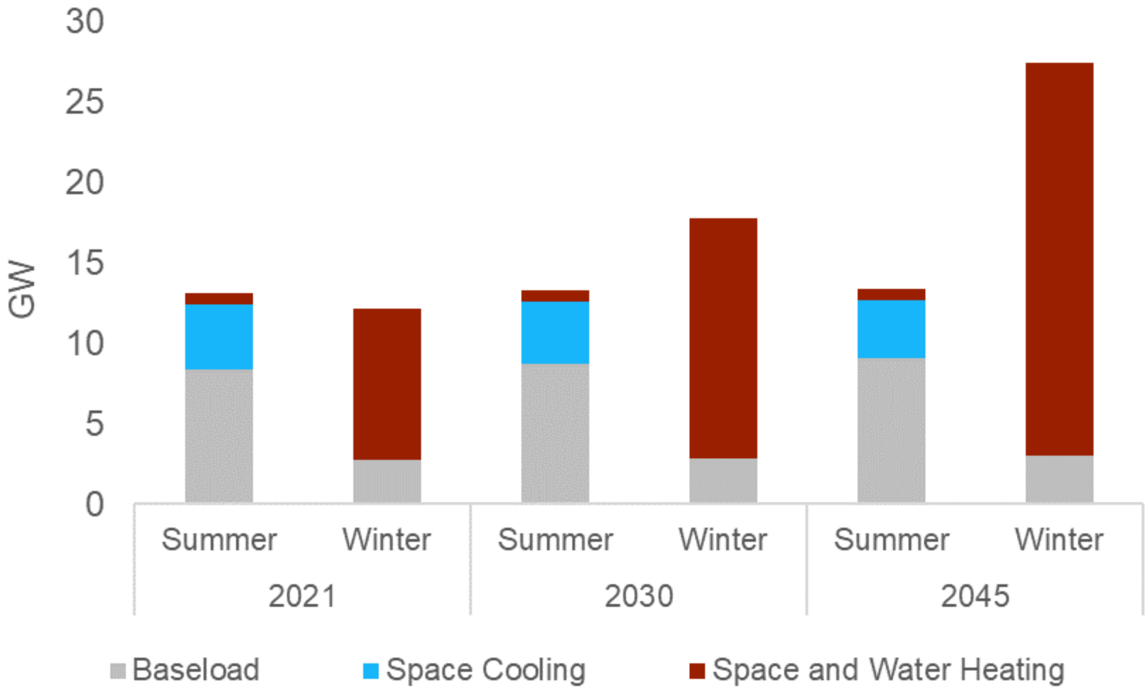
Winter peak load is expected to grow by 15 GW by 2045 in the High Electrification scenario

- **In the High Electrification scenario, Maryland's electricity system is expected to become winter peaking in the near future, and will more than double the current system peak by 2045**
  - Switching to heat pumps from electric resistance heating, which is currently used in about 25% of Maryland households, has a much smaller impact on peak heating load than on annual total heating loads

Peak Load Projection 2021-2045
High Electrification



Contribution to 1-in-2 System Peak by Sector
High Electrification – Current Installation Practice

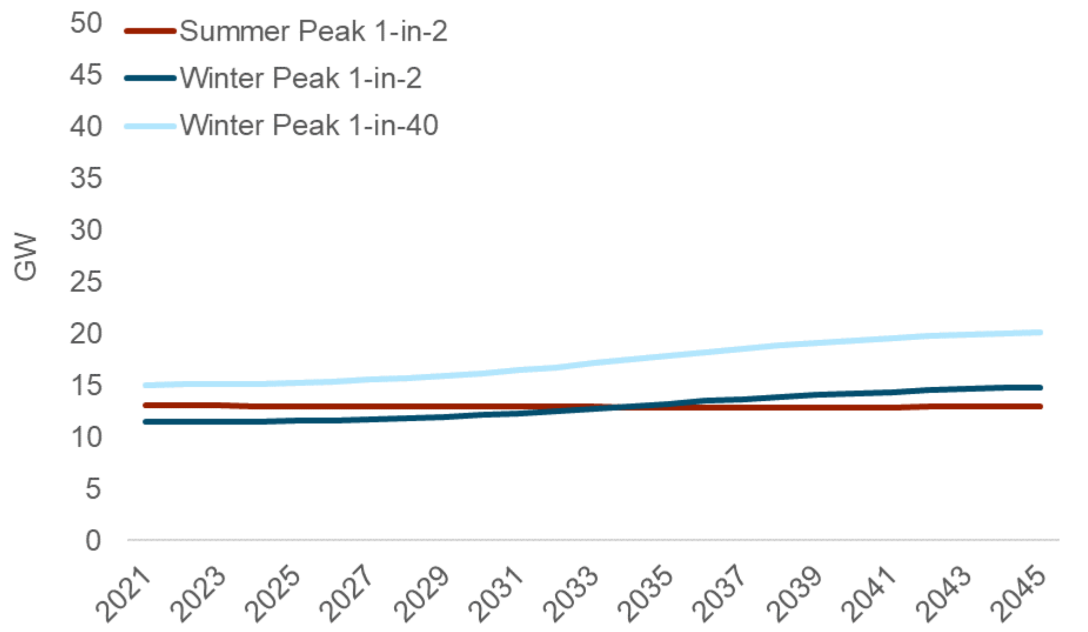


Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

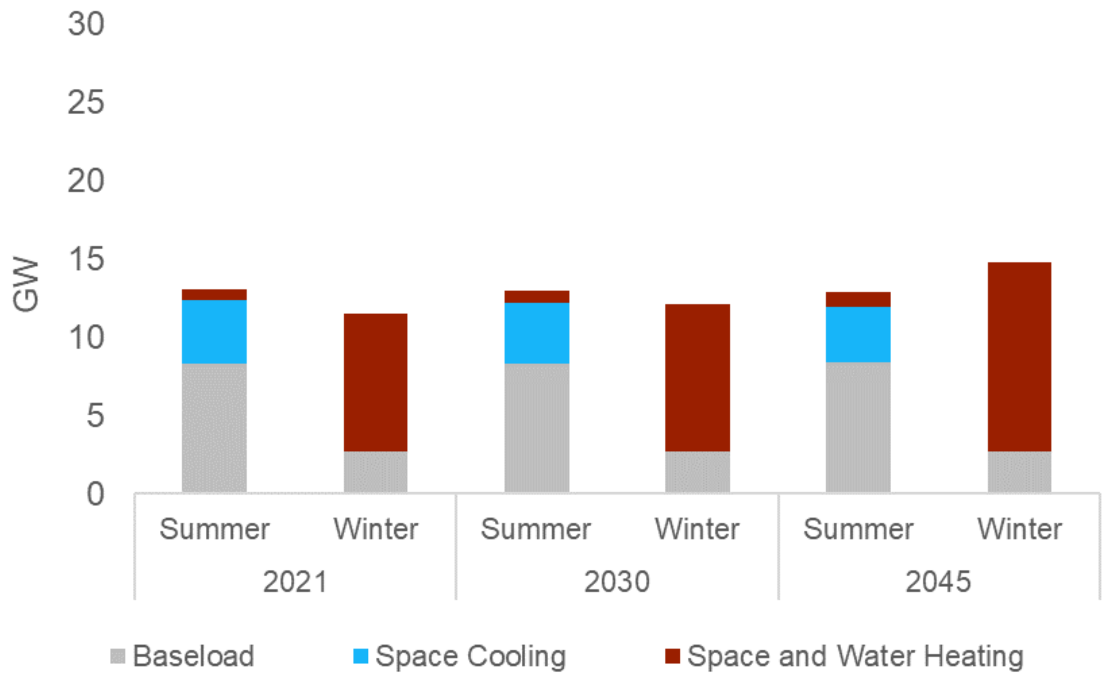
Electrification with Fuel Backup scenario has much smaller winter peak load growth

+ **Compared to the High Electrification scenario, Maryland's electricity system becomes winter peaking about a decade later**
+ **Peak load growth is also significantly smaller, ~2 GW by 2045 compared to the current system peak**

Peak Load Projection 2021-2045
Electrification with Fuel Backup



Contribution to 1-in-2 System Peak by Sector
Electrification with Fuel Backup



Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

System Cost Impact

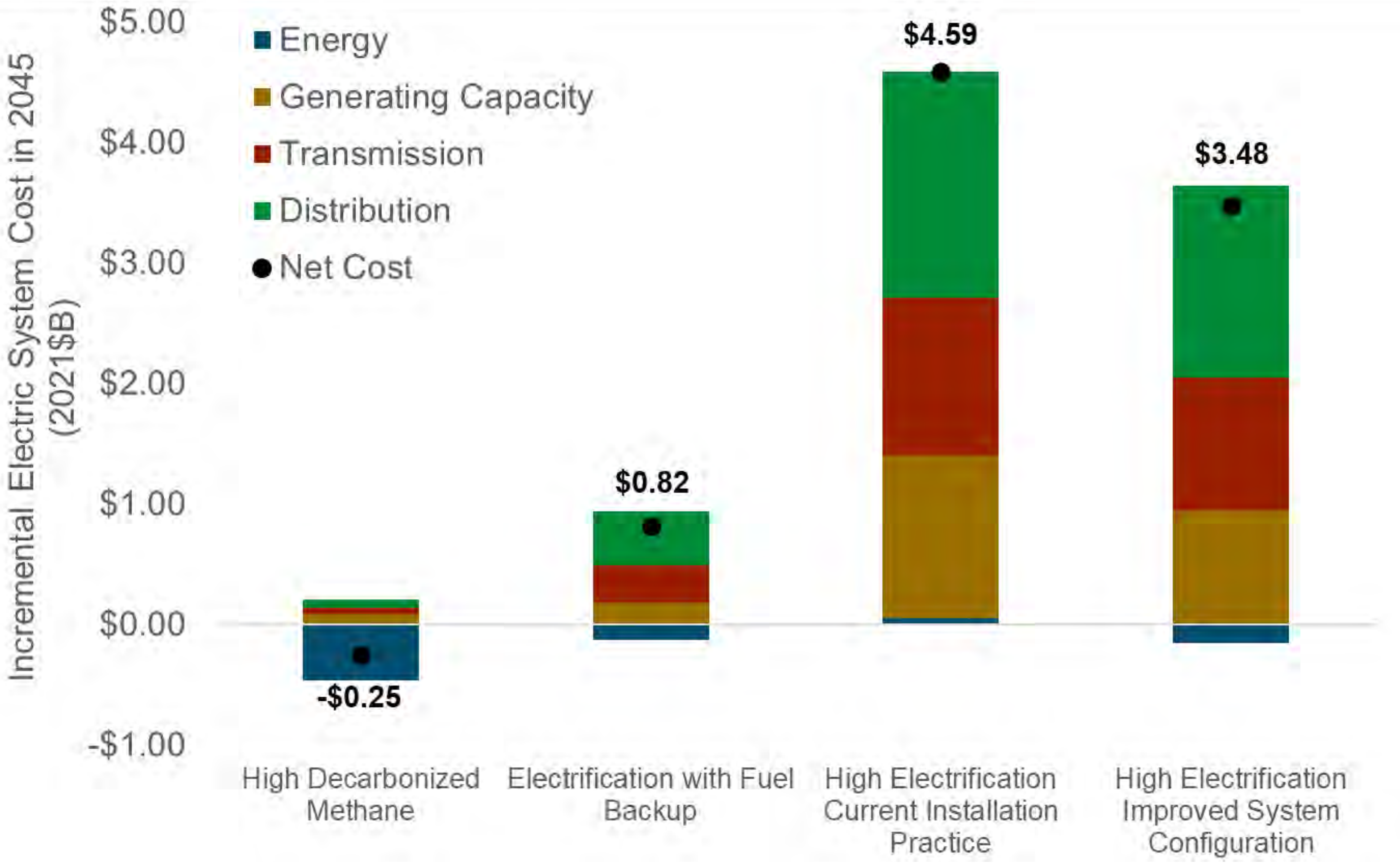
Approach for system cost impact analysis

- **The following four cost components are considered in the system cost impact analysis**
- **System costs of the three main scenarios are calculated as incremental to Reference**

Electric System	Gas System	Equipment	Other Fuels
❑ Investment in additional transmission and distribution infrastructure ❑ Investment in additional generating capacity to meet the peak electric demand ❑ Generation cost to meet the additional electricity demand	❑ Capital expenditure for reinvestment in the gas system ❑ Operating costs to maintain the gas system ❑ Gas commodity costs for RNG to replace natural gas	❑ Investment in efficient or electric appliances relative to a reference appliance ❑ Investment in building shell improvement	❑ Fuel commodity costs for bio-based liquid fuels to replace fossil fuels, mainly bio-diesel replacing fossil-based heating oil

Meeting electric loads in the High Electrification scenario requires around $4-5 billion of annual incremental system costs

Annual Incremental Electric System Costs relative to Reference in 2045 (2021$ Billions per year)

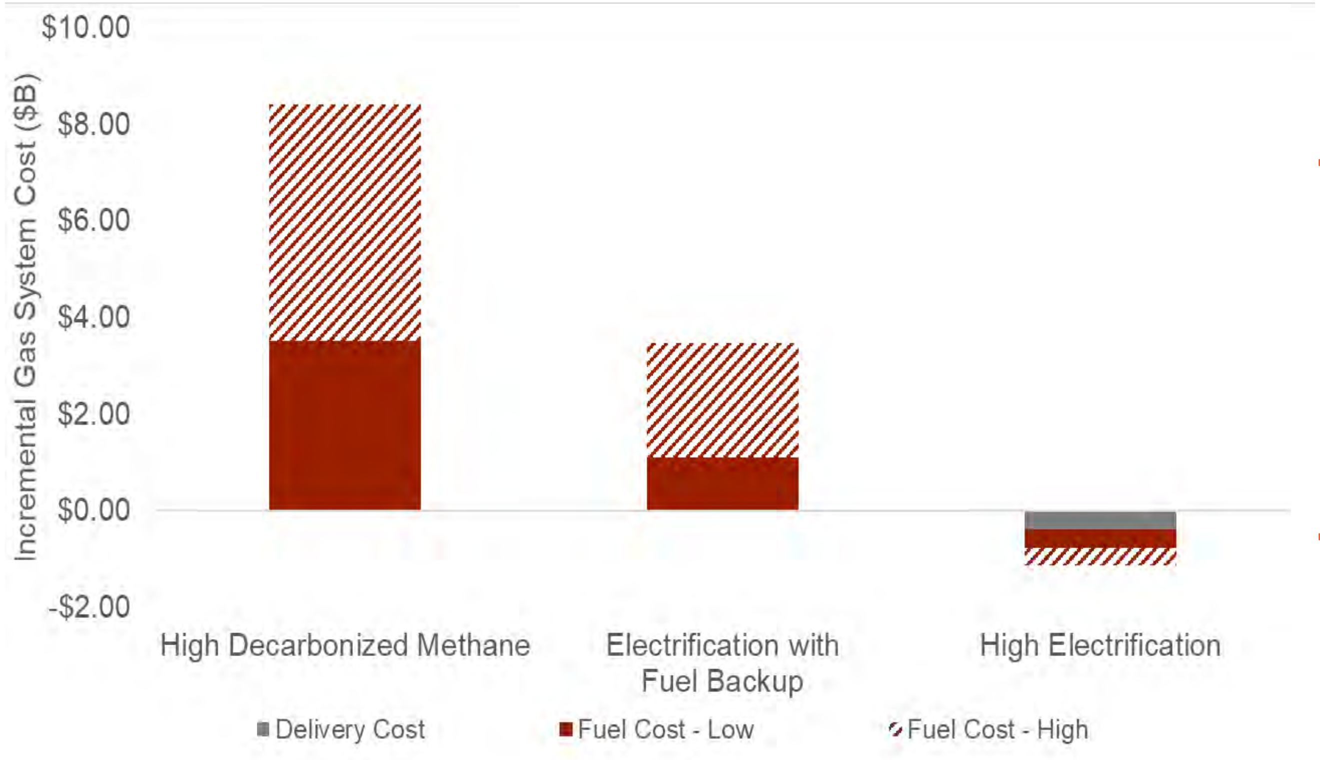


- **High levels of electrification significantly increase electricity system costs, mainly for meeting peak capacity needs.**
  - Improving system installation practices would result in less increase in electric system costs, only ~75% of that in the High Electrification scenario
- **Pairing ASHPs with fuel systems can save more than 80% of the incremental costs, mainly by avoiding T&D infrastructure and generating capacities**
  - System costs in the Electrification with Fuel Back Up scenario are $0.8 billion in 2045 compared to $4.6 billion for the High Electrification scenario

Sources & assumptions: Details of the electric sector cost assumptions are documented in the Appendix. T&D costs are high-level assumption reflecting new investment in lines. This captures the high-level investment requirement in the High Electrification Scenario given the magnitude of the peak impact from electrification. Further analysis is needed to explore near term opportunities for using headroom in existing T&D infrastructure and for expanding existing lines, which are likely going to be less expensive.

Gas system cost in all scenarios show wide ranges because of the large uncertainty associated with RNG commodity costs

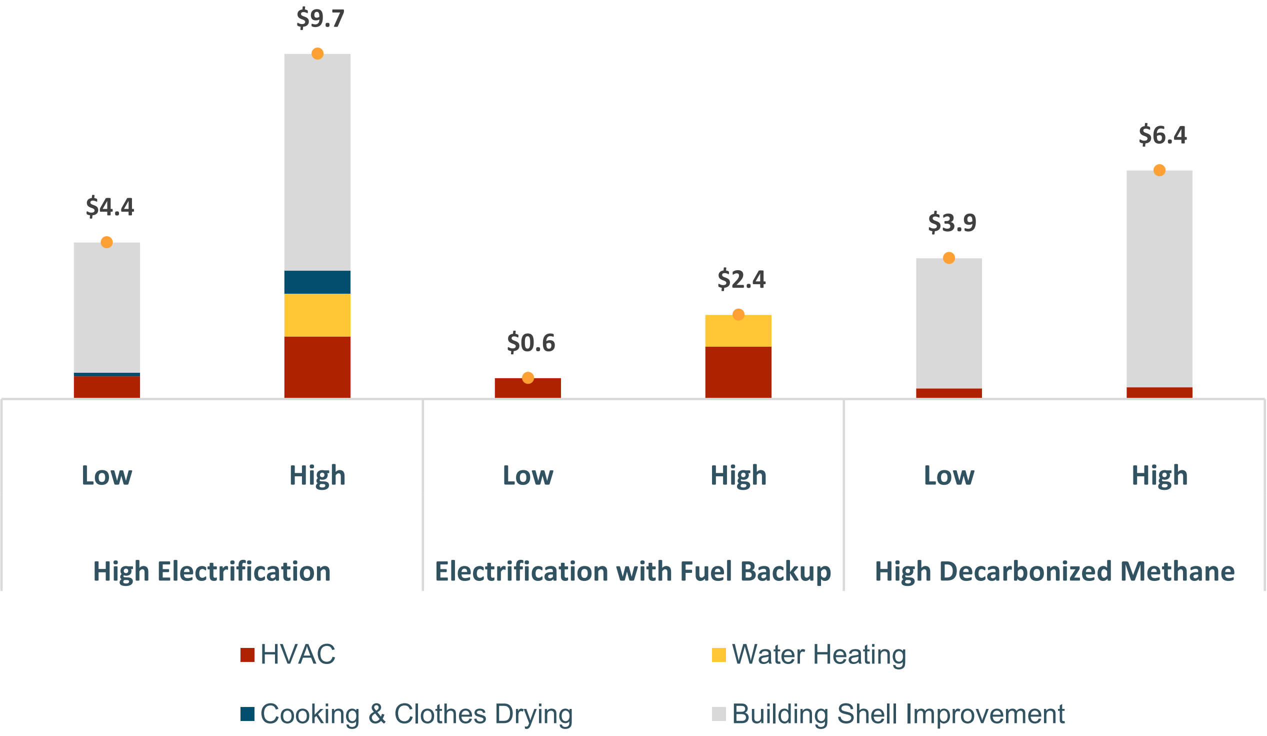
Annual Incremental Gas System Costs relative to Reference in 2045 ($2021 Billions per year)



- **High Decarbonized Methane** scenario has the biggest range of incremental system costs due to its high gas demand
  - Meeting all gas demand with RNG in the High Decarb Methane scenario can increase the annual gas system cost by up to $8B
- Reduced throughput in the **Electrification with Fuel Backup** scenario results in much lower system costs and less wide cost ranges
  - The blend of RNG results in higher gas commodity costs and overall gas system costs relative to Reference even though throughput is less
- **High Electrification** scenario has lower gas system costs relative to Reference due to both lower gas demand and lower infrastructure costs
  - We assume that reduced peak gas throughput in this scenario would require less capital reinvestment and O&M to maintain the gas system

The two book-end scenarios have relatively high incremental equipment costs due to building shell improvement

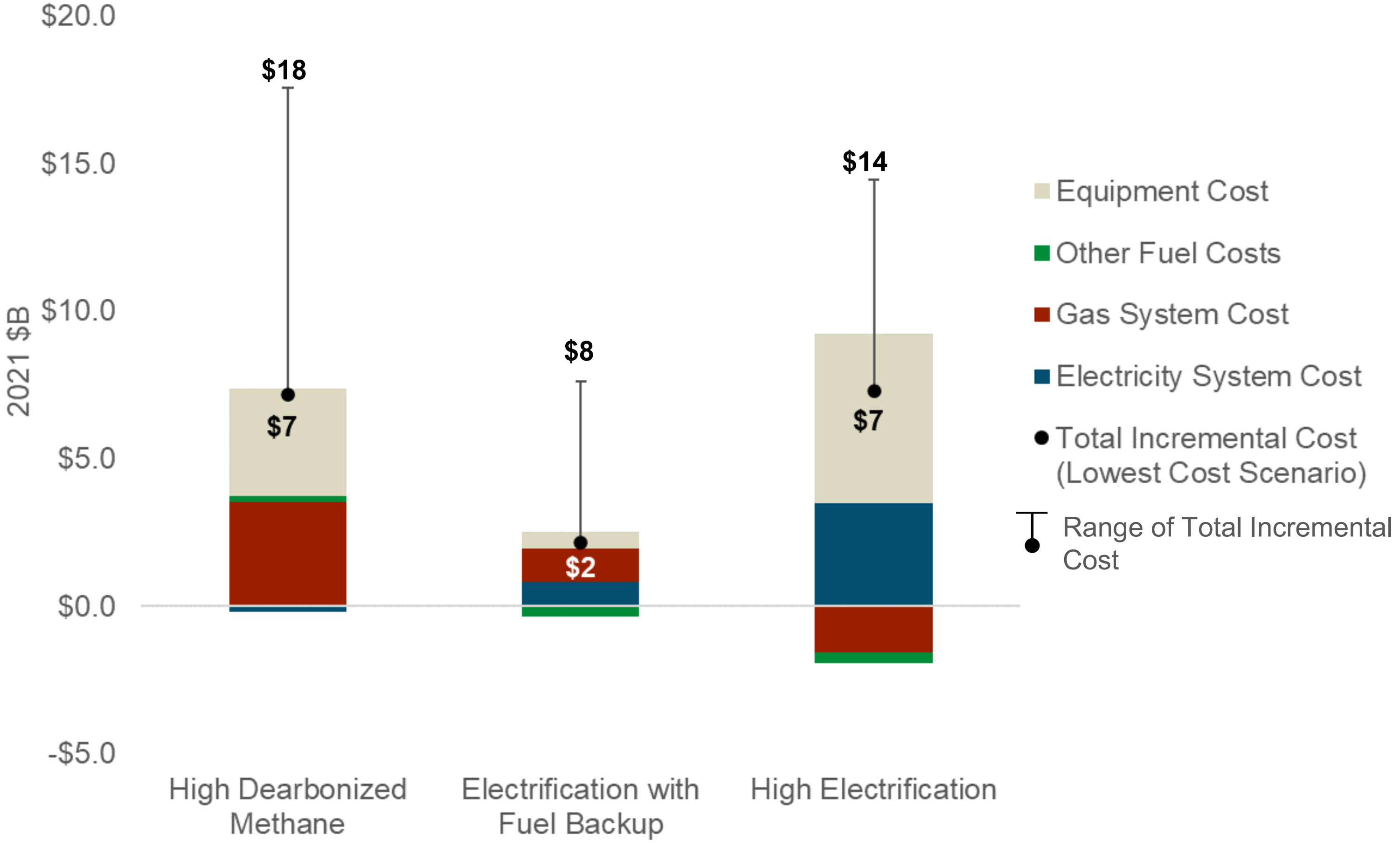
Levelized Total Incremental Equipment Costs in 2045 ($2021 Billions per year)



- **High and low equipment cost profiles creates uncertainty around future costs in the two book-end scenarios**
  - Building shell upgrades account for the majority of equipment costs
  - Current costs are based on deep shell retrofits that include energy efficiency and heat recovery, and are highly uncertain and location-specific
- **Electrification with Fuel Backup is the lowest-cost scenario because it does not include building shell improvement**

Electrification with Fuel Backup scenario is expected to be the relatively low-cost and low-risk among the three scenarios

Incremental Total Resource Costs for Buildings (2045) ($2021 Billions per year)



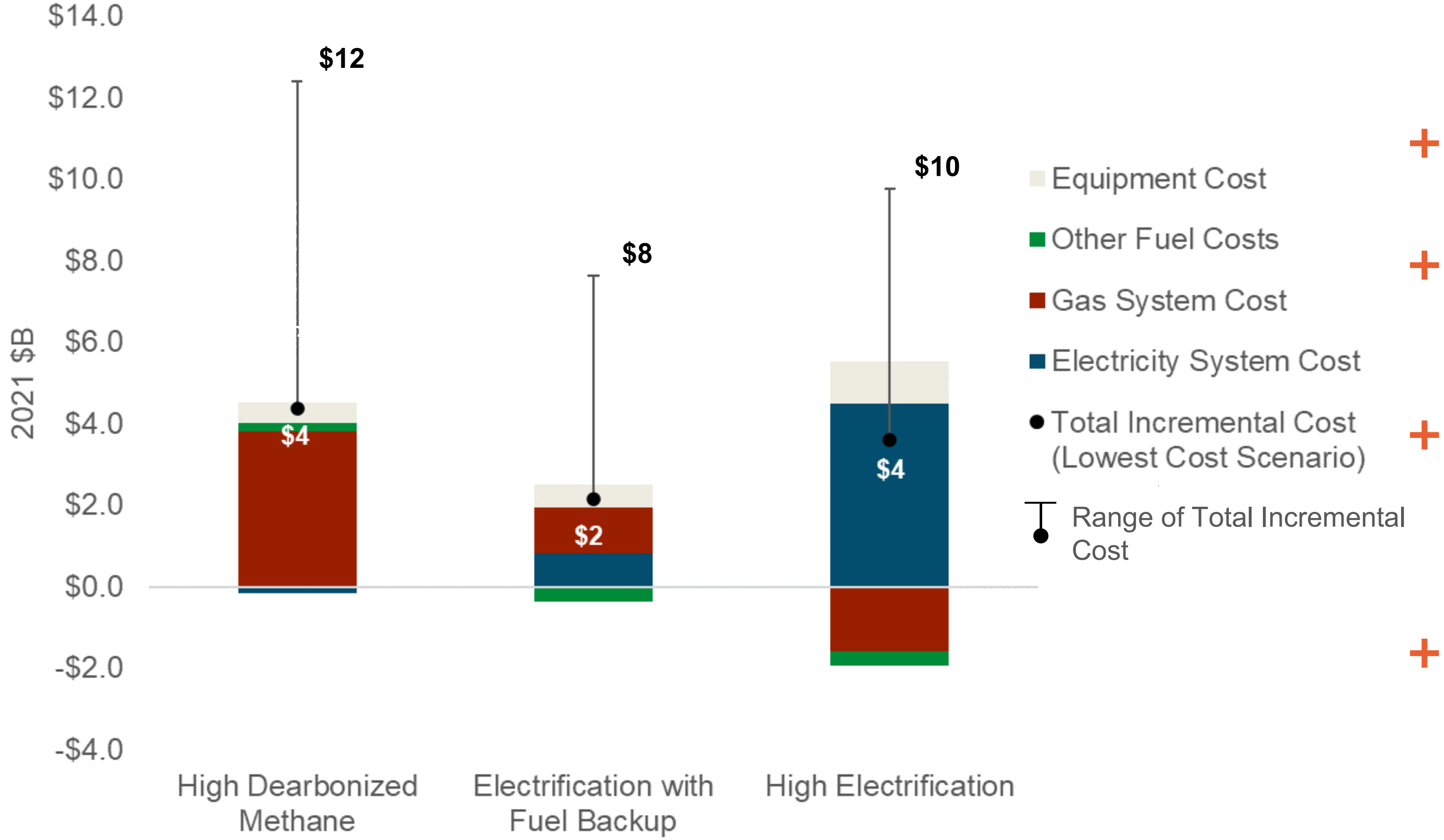
Total cost range reflects assumptions regarding fuel costs, equipment cost, and heat pump installation practices

- **Building sector costs show large variation across scenarios depending on:**
  - Gas fuel costs (optimistic/conservative supply curve)
  - Equipment costs (mainly building shell upgrade costs)
  - Installation practice for electric heating systems
- **A hybrid scenario could potentially "hedge" for this uncertainty given its lower overall costs and narrow cost ranges**

Sources & assumptions: These charts show incremental resource costs of the scenarios compared to the reference scenario.

When excluding retrofit shell improvement from the two bookend scenarios, Electrification with Fuel Backup scenario still shows relatively low-cost

Incremental Total Resource Costs for Buildings (2045) ($2021 Billions per year) – *No Retrofit Shell Improvement*



Total cost range reflects assumptions regarding fuel costs, equipment cost, and heat pump installation practices

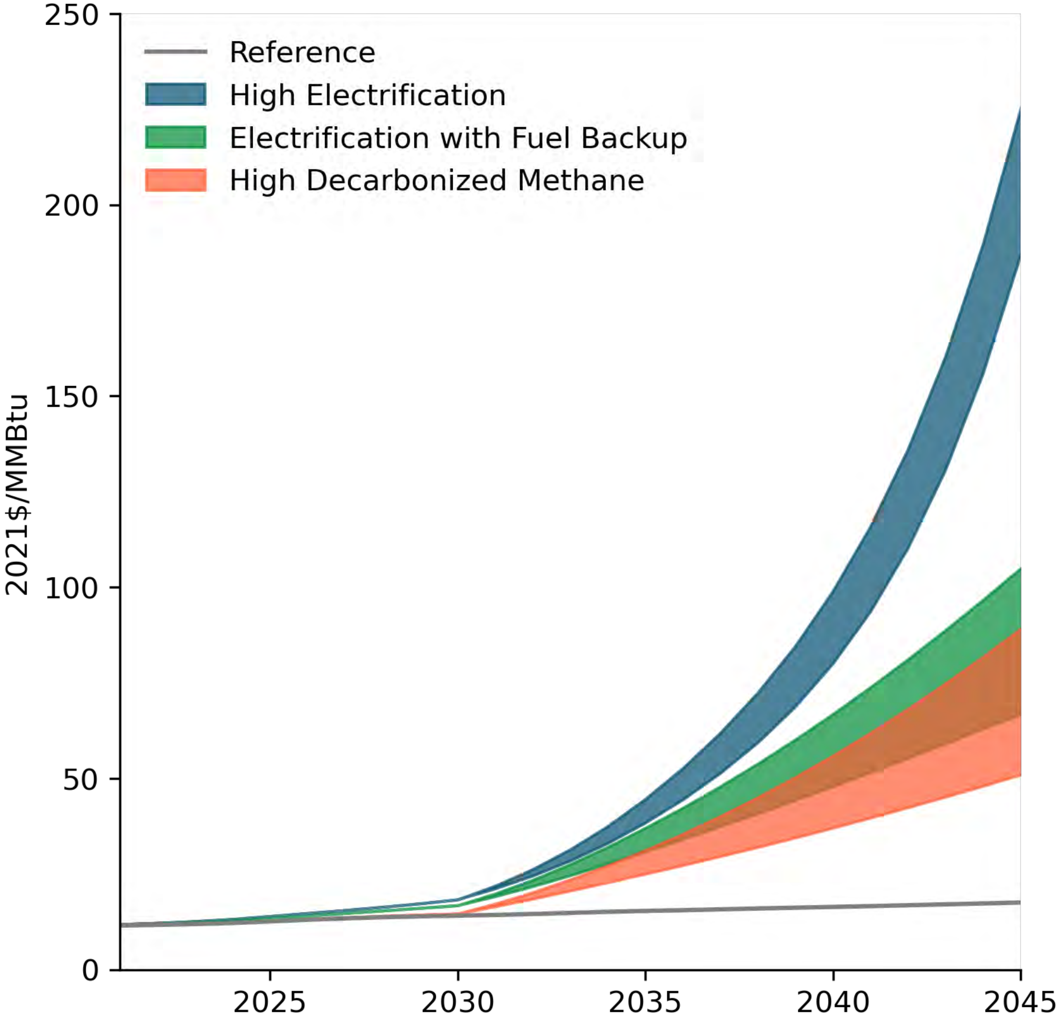
Sources & assumptions: These charts show incremental resource costs of the scenarios compared to the reference scenario.

- **The building shell measure considered in this study is illustrative of one type of deep shell retrofit, consisting of wall insulation, roof insulation, glazing, air-tightness, and heat recovery**
- **This study finds that applying the deep shell retrofit to all buildings is expensive**
- **E3 conducted a sensitivity analysis looking at the other bookend by removing the shell measure from all retrofit buildings**
- **Without retrofit shell improvement, Electrification with Fuel Backup scenario is still lower-cost than the High Decarbonized Methane and High Electrification scenarios**
- **The perfect mix of shell measures will likely be in the middle of the two bookends considered in study**
  - It will vary by building type and customer preference in terms of cost effectiveness, the comfort level it brings and other factors

Gas and Electric Rate Impact

Gas rates increase significantly across all scenarios

Residential gas rates (2021$/MMBtu)



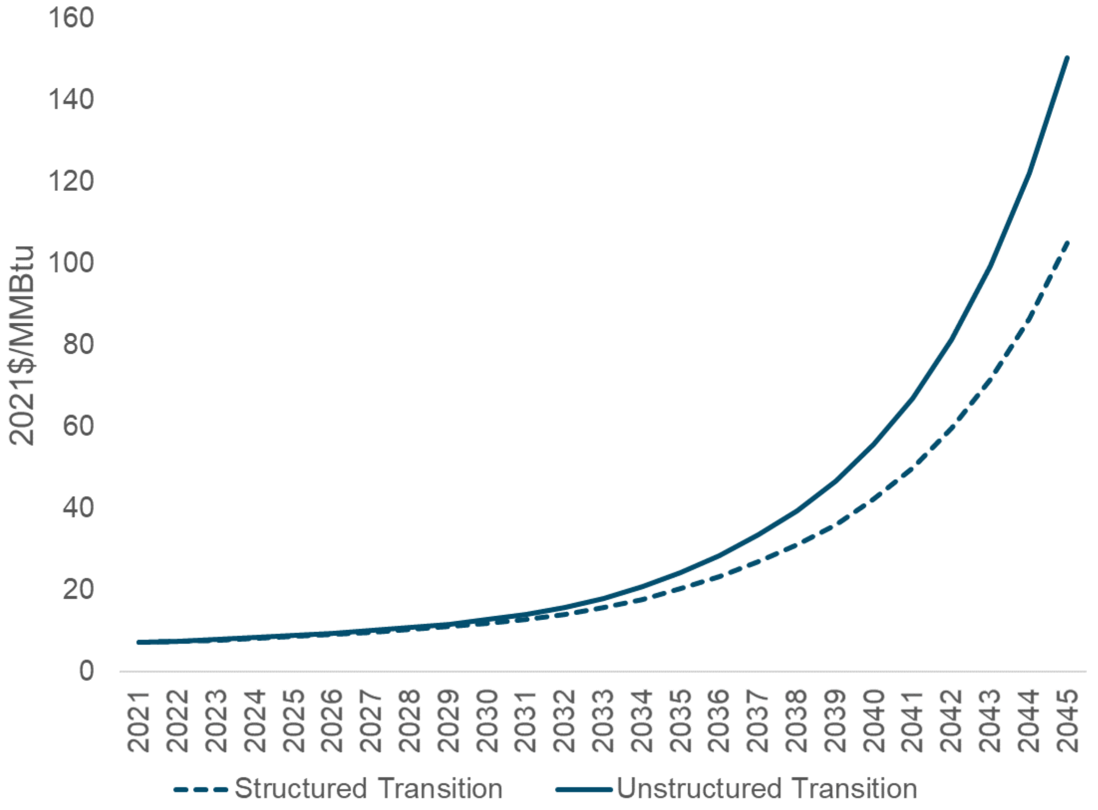
- **High Electrification scenario** experiences a rapid rate increase driven by declining throughput despite lower total delivery and commodity costs
- Rate increases in the **High Decarbonized Methane scenario** are driven primarily by the commodity cost for zero carbon fuel
- **Electrification with Fuel Backup scenario** has higher gas rates than the High Decarbonized Methane scenario, due to its lower throughput and the resulting higher per MMBtu delivery cost

*Range shown in figure reflects the commodity cost forecast uncertainty

Gas delivery rate under a structured gas transition may still remain high due to significantly reduced throughput

Residential gas delivery costs (2021$/MMBtu)

High Electrification with Structured Gas Transition

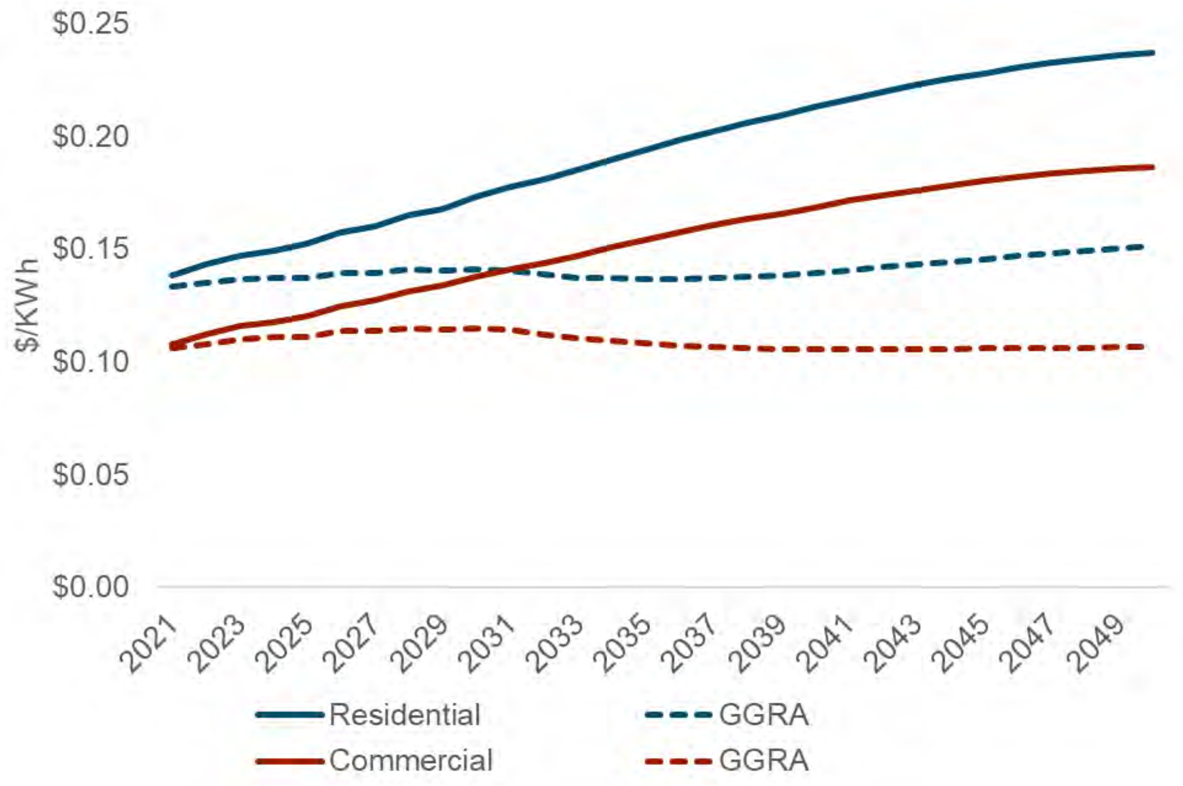


+ **E3 modeled an illustrative sensitivity scenario reflecting a high electrification future with structured gas transition, which would result in reduced level of revenue requirement compared to a base case**
  - Capital-related expenditure and pipeline maintenance costs become flat after 2030, which reflects half of the reinvestment level compared to today
    - Data source: E3 (2020), The Challenge of Retail Gas in California's Low Carbon Future
  - Administrative costs are reduced by 0.6% with every 1% reduction in customer base
    - Data source: Davis and Hausman (2021), Who Will Pay for Legacy Utility Costs?
+ **The structured transition reduces residential delivery rates by 30%, but the rates remain high**
+ **This sensitivity does not address the question of how utilities would reduce the revenue requirement or who would bear the cost gap between reduced revenue requirement and unavoidable costs for the remaining gas system**
+ **More legislative and regulatory efforts are needed to address the issues of stranded gas assets in a high electrification future**

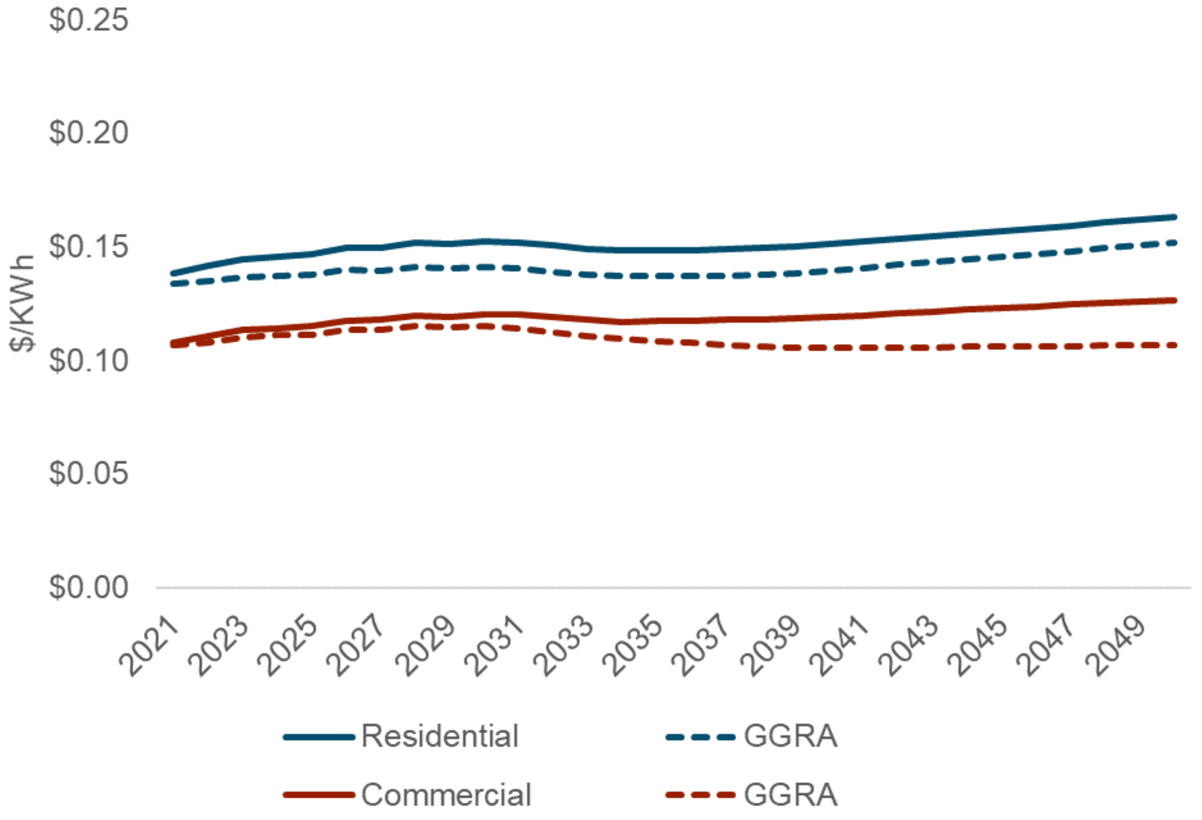
High Electrification scenario shows a more rapid electric rate increase compared to Electrification with Gas Back Up

- The Electrification + Gas Back-up scenario is projected to have a lower rate increase because it has a smaller load factor and manages to avoid the expensive peak capacity investment.

Electric rates in the High Electrification Scenario (2021$/kWh)



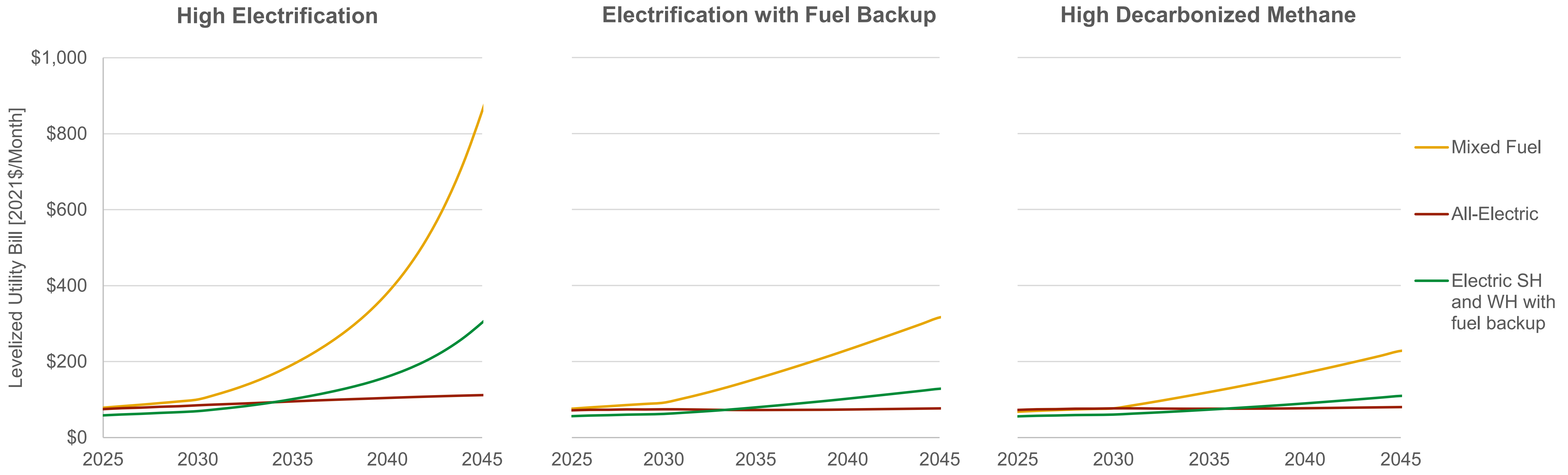
Electric rates in the Electrification + Gas Back-up Scenario (2021$/kWh)



Consumer Economics

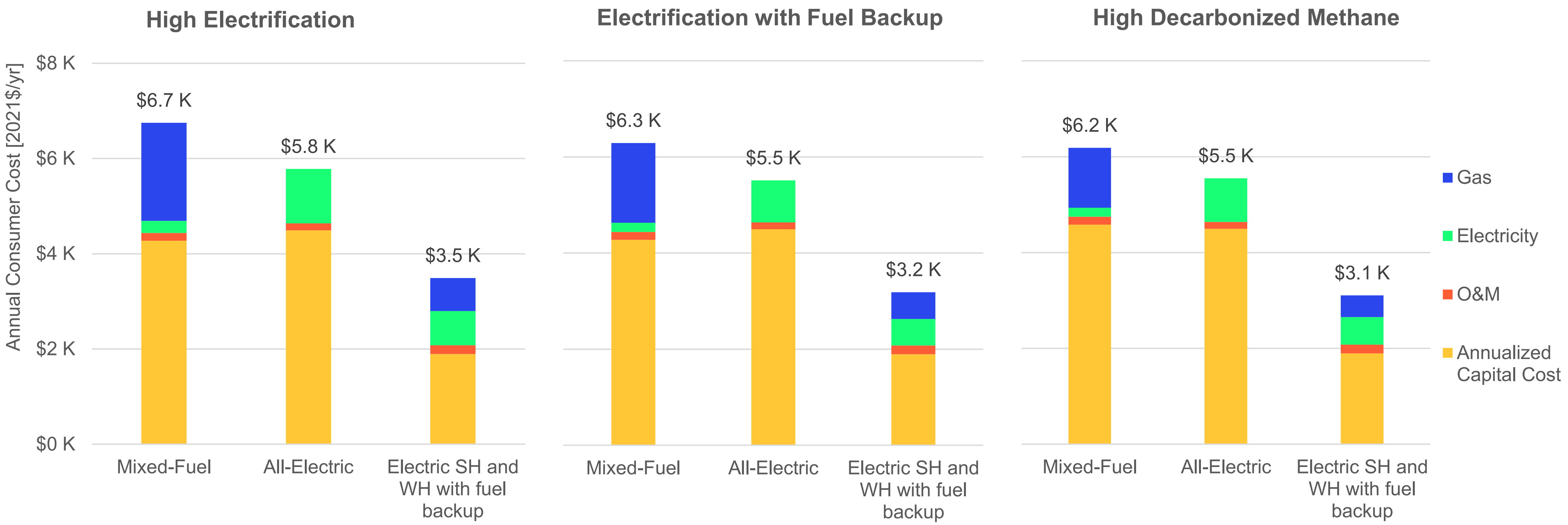
Illustrative customer bill impacts – residential single-family

- Across all scenarios, customers remaining on the gas system may experience a large increase in utility bills due to the blend of expensive RNG to decarbonize gas use
- CAVEAT: These are not predictions of customer bills, but a representation of the potential dynamics under the current ratemaking model. These results indicate the potential equity and affordability challenges that will require systemic changes to the current dynamics.



Electrifying heating with fuel backup is expected to be the least expensive option when both capital and operating costs are considered

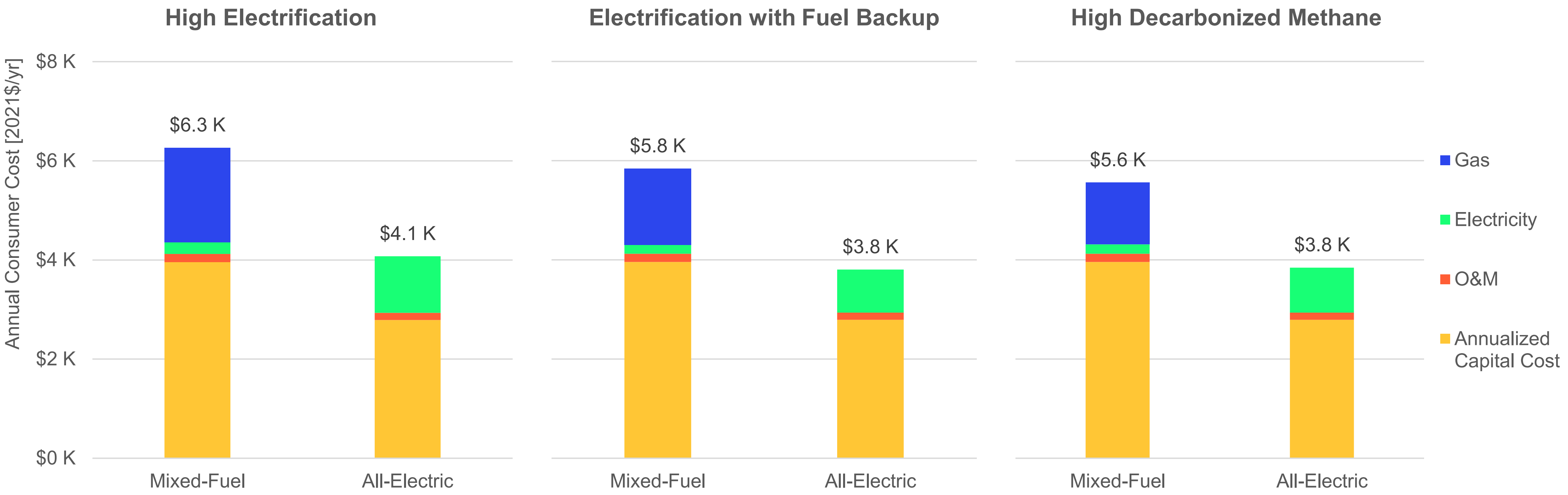
+ **"Hybrid" customers can save money by utilizing their existing fuel-based heating equipment to provide backup heating during coldest hours of a year, and by not having to upgrade building shells**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent "optimistic" rate scenario ("conservative" gas scenario has 5% higher total cost for mixed-fuel)

All-electric design is expected to be the less expensive option

+ **All-electric new construction is cheaper than mixed-fuel new construction for single-family residential homes across all decarbonization scenarios due to both lower capital (with avoided gas connection) and operating costs**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent “optimistic” rate scenario (“conservative” gas scenario has 5% higher total cost for mixed-fuel)

Energy+Environmental Economics

Conclusions

Conclusions

+ **All scenarios** demonstrate technologically feasible pathways to achieve zero direct building emissions by 2045, but require extensive technology deployment and commercialization efforts.
+ The **Electrification with Fuel Backup** pathway shows lowest overall costs while also reducing reliance on technologies that have not yet been widely commercialized or that are uncertain in their scalability.
  - The **High Decarbonized Methane** pathway requires high demand for zero-carbon fuels, resulting in high incremental fuel costs with significant cost uncertainty
  - The **High Electrification** pathway results in a shift from a summer peak to a winter peak, mainly as a result of space heating loads in winter.
+ Consumers in **retrofit buildings** can save costs by employing a dual-fuel heating system with heat pumps providing majority of the heating need and fuel system providing backup during the coldest hours
  - **All-electric new construction** is found to be less expensive considering both equipment and fuel costs than those connecting to gas grid and using fuels for heating

Conclusions (cont'd)

- **Achieving the Electrification with Fuel Backup pathway** would require careful policy design that incentivizes consumers to employ dual-fuel heating systems
  - For example, the current ratemaking model likely needs to be revisited, so that the right price signals are reflected in gas and electric rates and incentive consumers to switch to fuel backups during cold hours
- **Each scenario** presents its own equity and affordability challenges
  - The average costs of the gas service are likely to increase in an electrification scenario as customers leave the system and infrastructure costs are spread over a smaller customer base.
  - Emphasis on mitigating the energy burden with customers 'staying behind' is important.
- The single **building shell measure** considered in this study is expensive. The perfect mix of shell measures will vary by building type and customer preference in terms of cost effectiveness, the comfort level it brings and other factors
- **Other factors** including but not limited to health impact, job impact and methane leakage, which are beyond the scope of this study, need further investigation to provide a more complete evaluation of impact of the different pathways

MWG Policy Scenario

Energy+Environmental Economics

Content of MWG Policy Scenario

+ **Background**
+ **Modeling Assumptions**
+ **GHG Emissions and Energy Consumption**
+ **System Cost Impact**
+ **Gas and Electric Rate Impact**
+ **Customer Economics**
+ **Summary of Findings**

Background

- **MDE and MWG designed a "Residential Electrification and Commercial Emissions Standard" scenario (referred to as "MWG Policy Scenario" in this slide report), based on feedback from the MWG participants for the E3 study**
- **Key assumptions for the MWG Policy Scenario include:**
  - **All-electric new construction**
  - **High electrification retrofits for existing residential buildings**
  - **Dual-fuel retrofits for existing commercial buildings, reflecting a Building Emissions Standard targeting net-zero emissions for commercial buildings by 2040 proposed in the draft Building Energy Transition Plan**
- **This slide report summarizes E3's modeling assumptions and results for the MWG Policy Scenario**

Modeling Assumptions

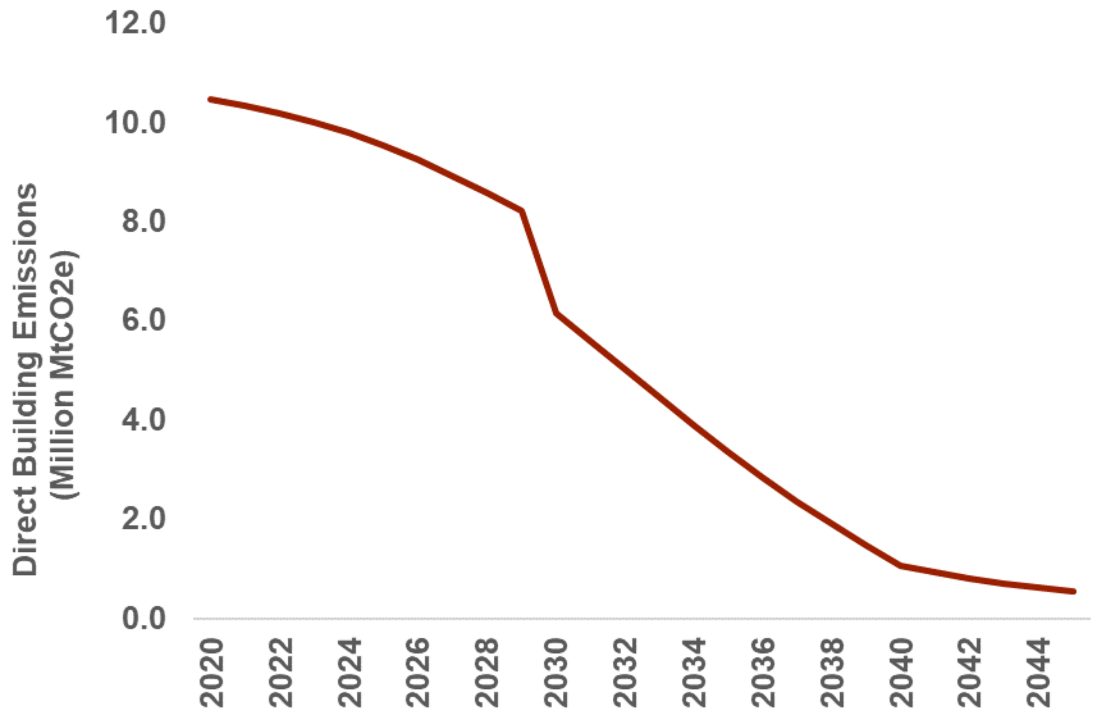
+ **E3 leveraged the existing analysis to model the MWG Policy Scenario by:**
  - **Applying residential electrification and efficiency measures from the High Electrification scenario**
  - **Applying commercial electrification and efficiency measures from the Electrification with Fuel Backup scenario**
  - **Assuming no low-carbon fuels for residential and commercial and use previously modeled Reference Scenario natural gas assumptions**
  - **Assuming commercial building owners would pay $100/tCO2 for remaining emissions, modeled as "alternative compliance" costs**
    - Assume alternative compliance payments begin in 2030 for all commercial sector emissions greater than 50% of 2020 sector emissions levels
    - Assume cap on commercial emissions decreasing at a linear rate from a 50% reduction in 2030 to a 100% reduction in 2040

Energy+Environmental Economics

GHG Emissions and Energy Consumption

MWG Policy scenario leads to a 95% decline in direct building emissions

Direct building GHG emissions trajectory (MMtCO2e per year)

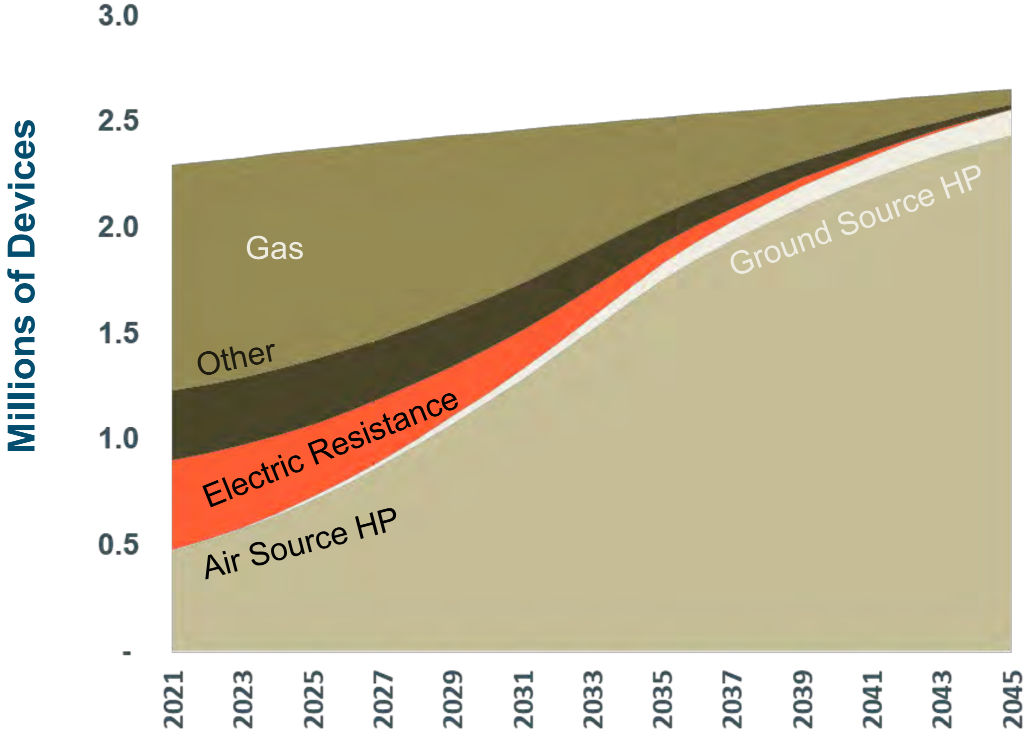


- **Direct building emissions decline by 95% in this MWG policy scenario.**
- **Residential** emission decline by 90% with **0.6 million MtCO2e** remaining emissions from residential buildings **in 2045** due to electrification.
- All remaining **commercial** sector emissions are offset by alternative compliance payments in 2045. Alternative compliance payments offset **3.1 million MtCO2e in 2045**.

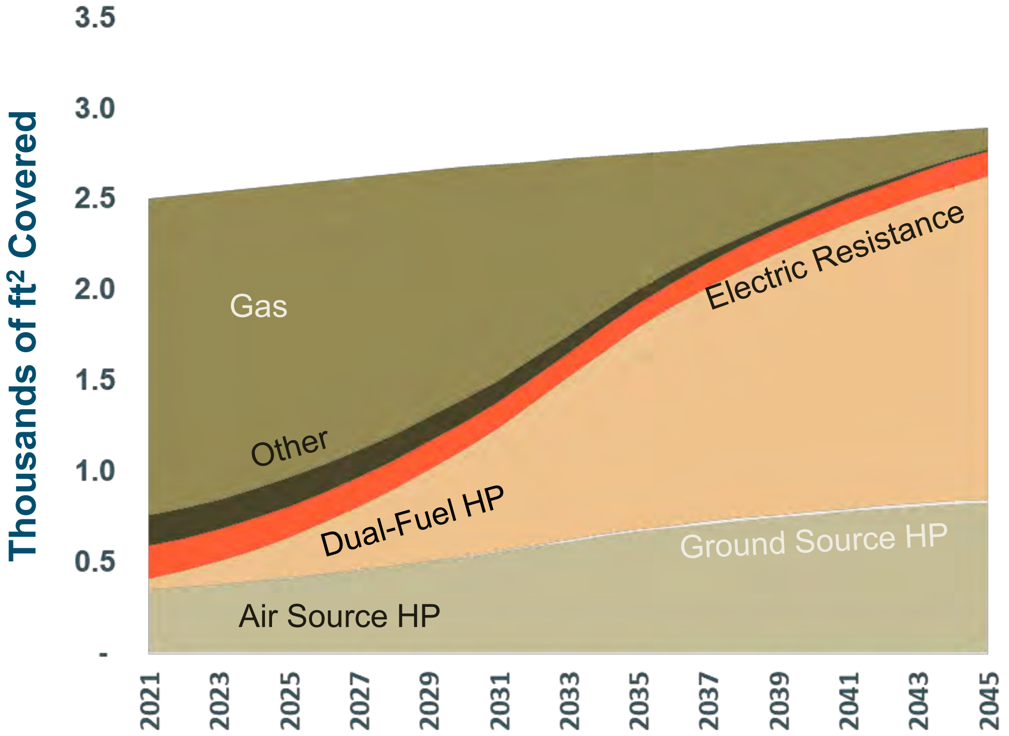
Space heating end-uses are mostly electrified by 2045 in the MWG Scenario

- Heat pumps become the major space heating equipment in both residential and commercial buildings
- Dual-fuel heat pumps are added to most retrofit commercial buildings, pairing with existing fuel-based systems

MWG Policy Scenario – Residential



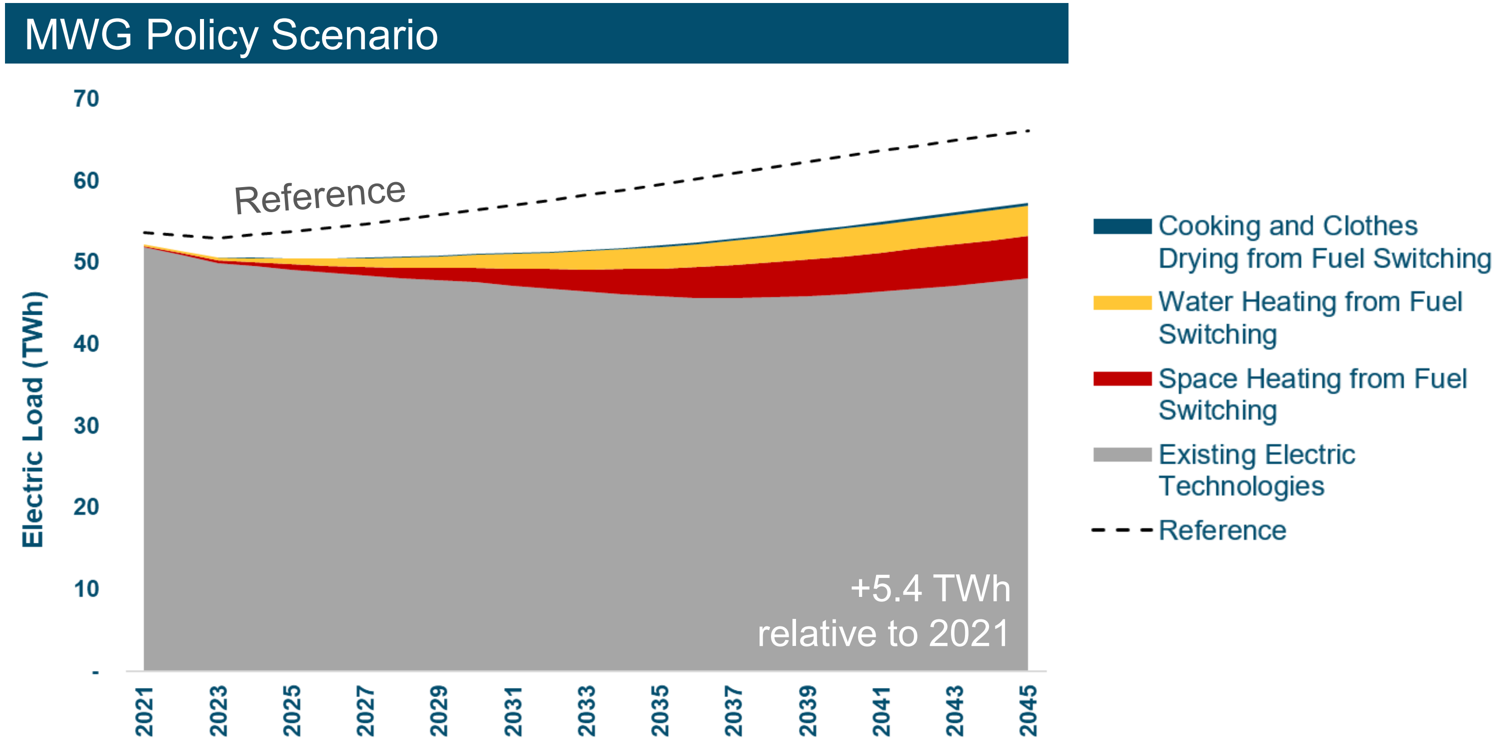
MWG Policy Scenario – Commercial



* "Other" space heating devices mainly include fuel oil and LPG-based furnaces and boilers
* Consistent with the 2030 GGRA Plan, the Electrification with Fuel Backup and High Decarbonized Methane scenarios assume continuation of EMPOWER program after 2023
* E3 is working with MDE to evaluate the impact of geothermal heating and cooling carve-out requirement in the RPS on GSHP adoption assumptions across the scenarios

Electricity demand in the MWG Scenario are lower than Reference due to energy efficiency gains

- **Electricity demand increases mainly due to new space heating, water heating and other loads as a result of fuel switching**
- **Compared to Reference, all scenarios have lower electricity demand due to energy efficiency gains**

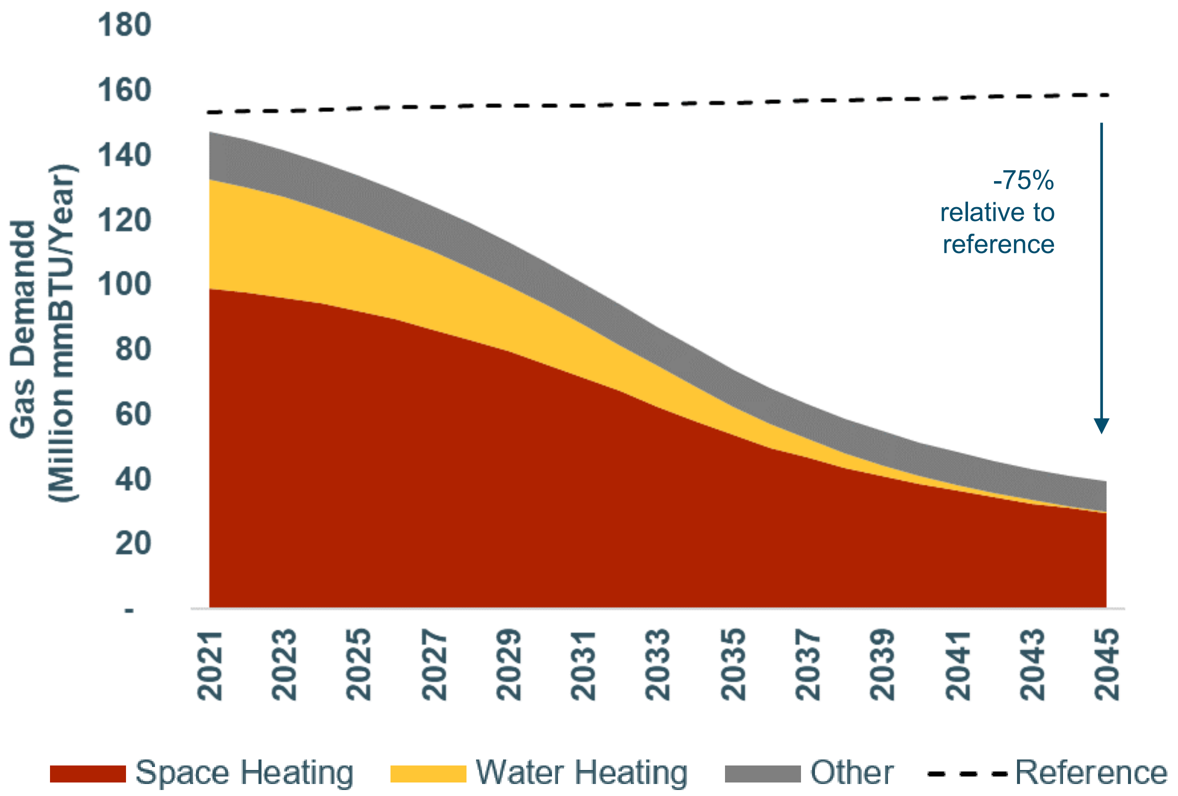


Natural gas demand declines in the MWG Policy Scenario due to fuel switching

- **MWG Policy Scenario** reduces gas demand by **75%** by 2045 due to
  - Aggressive electrification of all end-uses in residential buildings
  - Adoption of dual-fuel heat pumps that use gas as a backup heating source during coldest hours of the year by most commercial customers

Segment	Gas Demand (TBtu/yr)		% Change vs 2021
	2021	2045	
Residential	73	3	-95%
Commercial	79	40	-49%

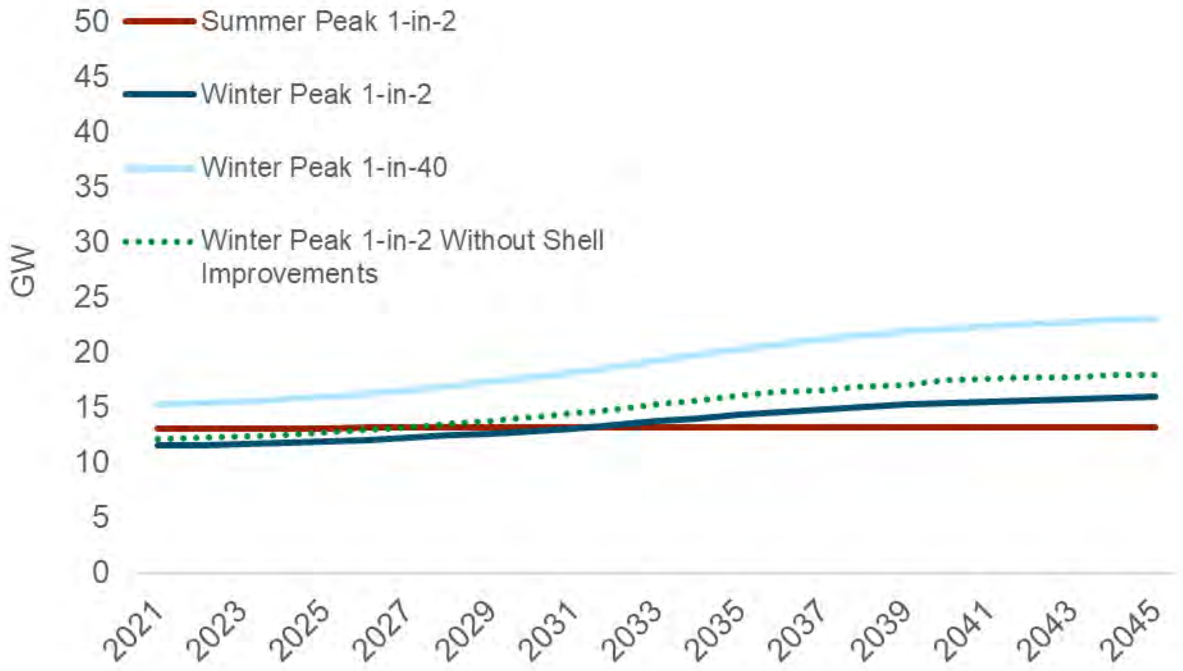
MWG Policy Scenario



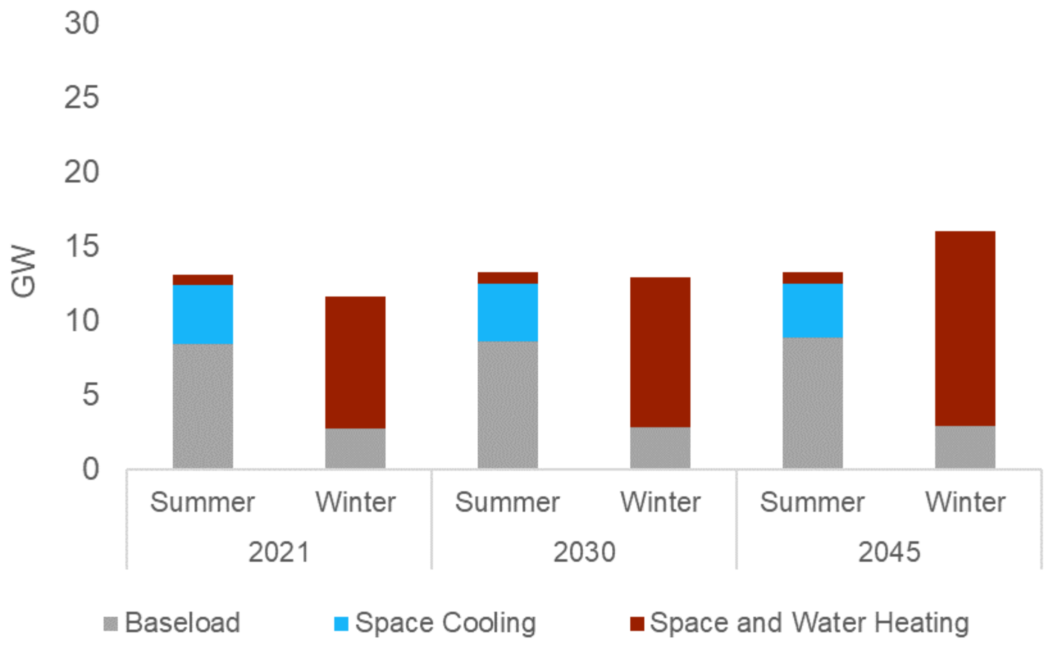
Electric System Peak Impacts

- Maryland's electricity system becomes winter peaking under the MWG Policy Scenario
- Peak load growth is also significantly smaller, ~3 GW by 2045 compared to the current system peak, but peak load growth is greater in this scenario than the Electrification with Fuel Backup scenario.

Peak Load Projection 2021-2045
MWG Policy Scenario



Contribution to 1-in-2 System Peak By Sector
MWG Policy Scenario



Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

System Cost Impact

Approach for system cost impact analysis

- **The following four cost components are considered in the system cost impact analysis**
- **System costs of the three main scenarios are calculated as incremental to Reference**

Electric System

- Investment in additional transmission and distribution infrastructure
- Investment in additional generating capacity to meet the peak electric demand
- Generation cost to meet the additional electricity demand

Gas System

- Capital expenditure for reinvestment in the gas system
- Operating costs to maintain the gas system
- Gas commodity costs for RNG to replace natural gas

Equipment

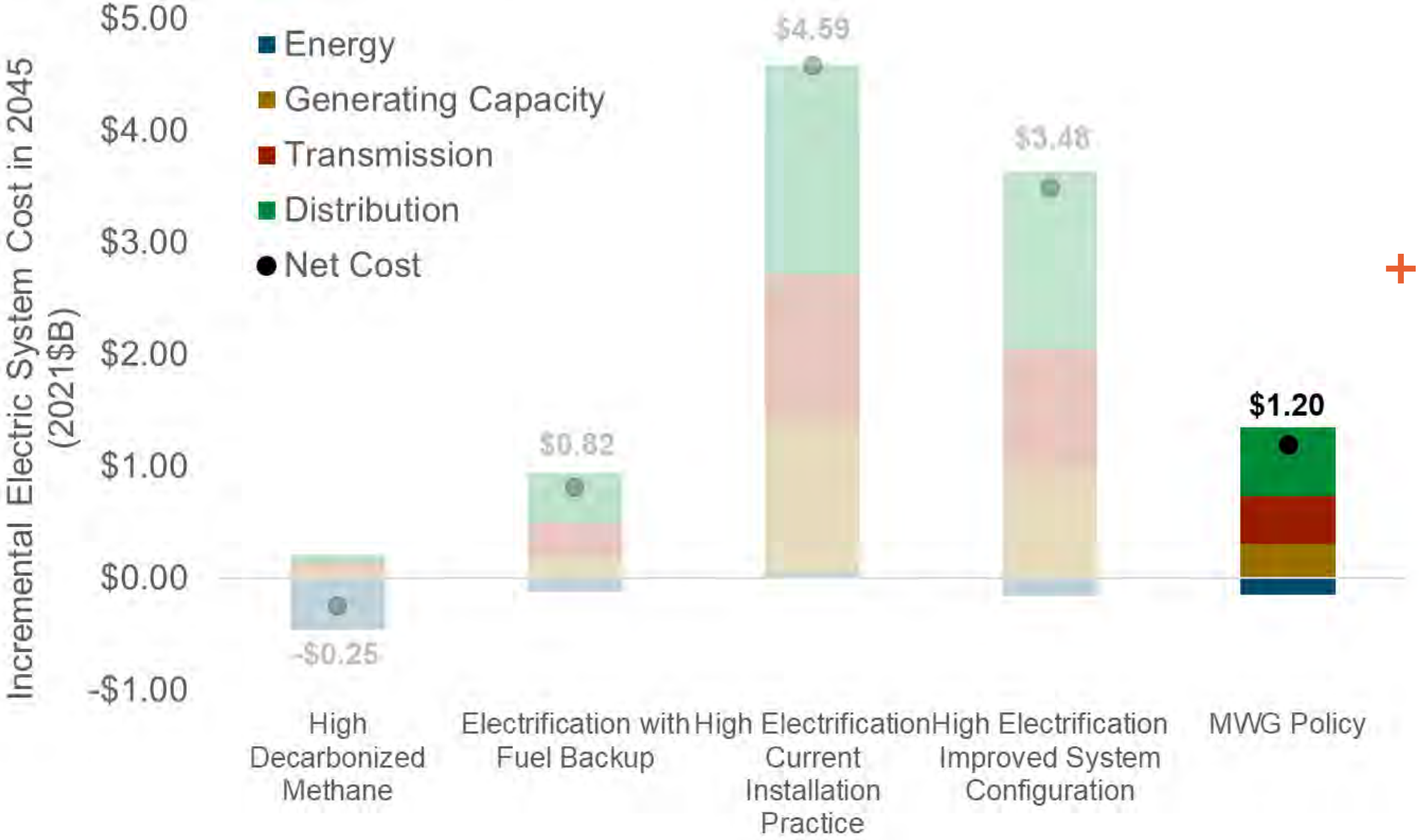
- Investment in efficient or electric appliances relative to a reference appliance
- Investment in building shell improvement

Other Fuels

- Fuel commodity costs for bio-based liquid fuels to replace fossil fuels, mainly bio-diesel replacing fossil-based heating oil

Meeting electric loads in the MWG Policy Scenario requires around $1 billion of annual incremental system costs

Annual Incremental Electric System Costs relative to Reference in 2045 (2021$ Billions per year)

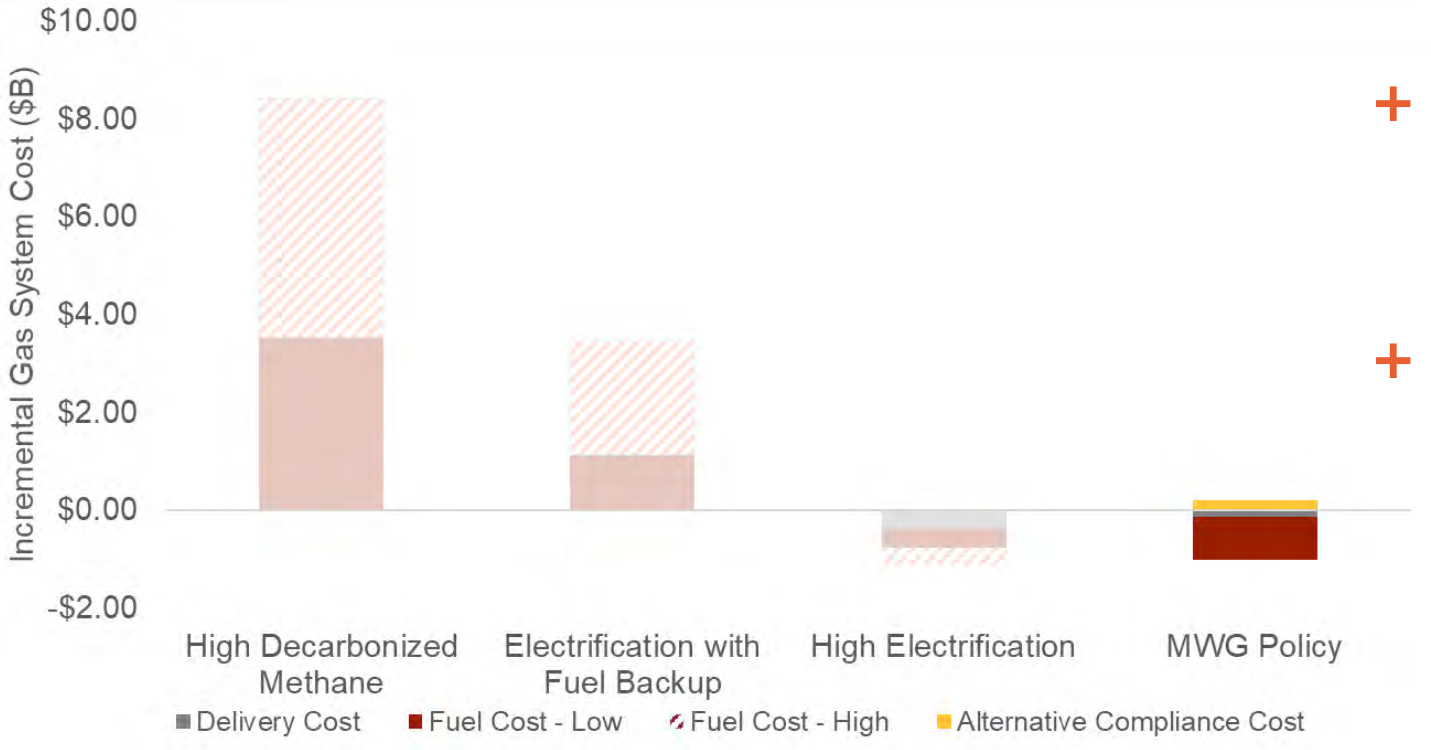


- Electrification of new construction and residential buildings in the MWG Policy scenario increase electricity system costs, mainly for meeting peak capacity needs.
- Dual fuel retrofits of commercial buildings rather than all-electric retrofits reduces incremental electric system costs by ~74% in the MWG Policy scenario compared to the High Electrification Scenario.

Sources & assumptions: Details of the electric sector cost assumptions are documented in the Appendix. T&D costs are high-level assumption reflecting new investment in lines. This captures the high-level investment requirement in the High Electrification Scenario given the magnitude of the peak impact from electrification. Further analysis is needed to explore near term opportunities for using headroom in existing T&D infrastructure and for expanding existing lines, which are likely going to be less expensive.

MWG Policy Scenario has lower total gas system costs relative to Reference, mainly due to reduced gas throughput

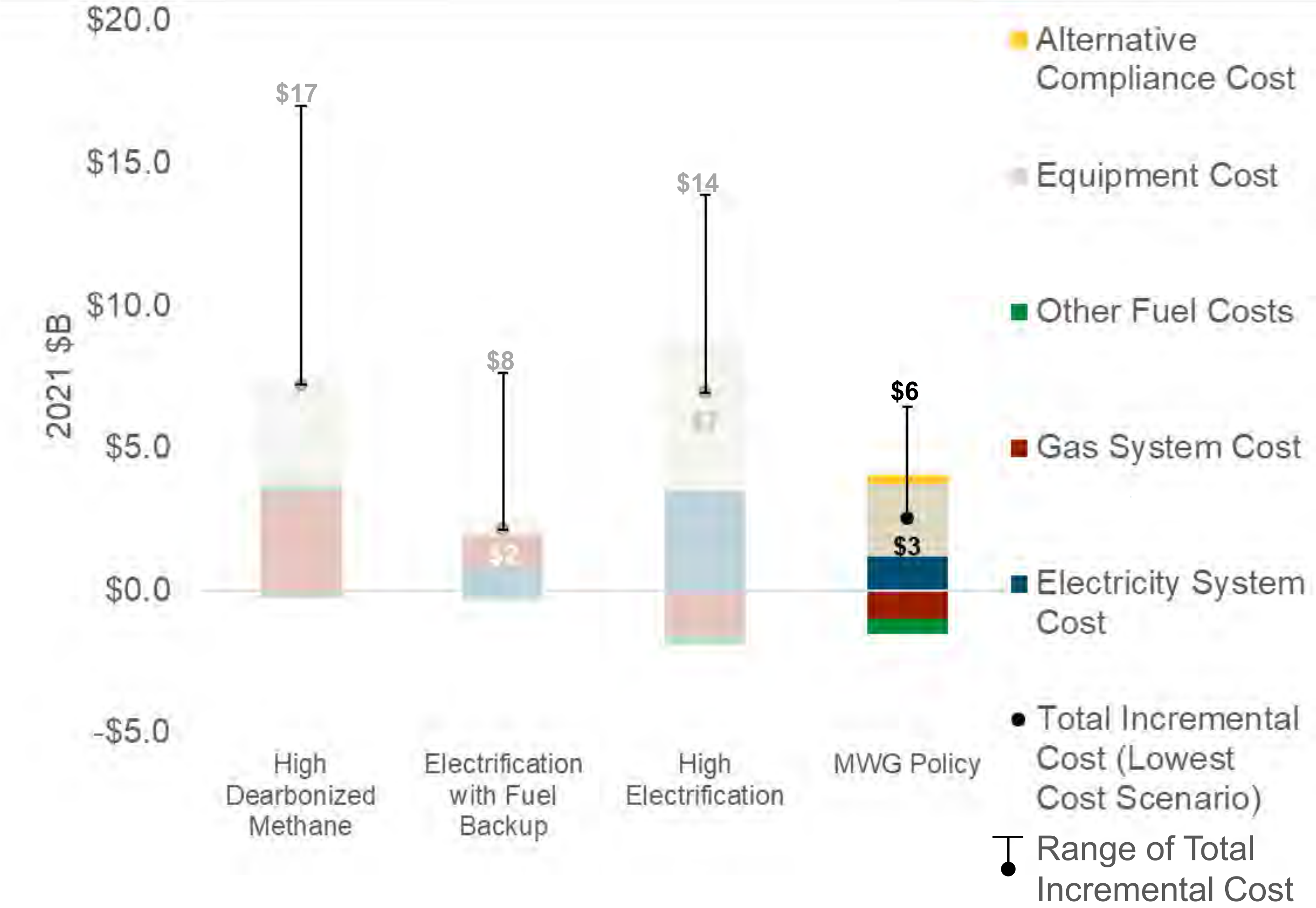
Annual Incremental Gas System Costs relative to Reference in 2045 ($2021 Billions per year)



- **The MWG Policy Scenario has lower gas fuel costs compared to Reference due to reduced gas throughput and not using the expensive low-carbon gas**
- **The alternative compliance cost is relatively small compared to the gas fuel savings, resulting in net gas system cost savings in the MWG Policy Scenario relative to Reference**

MWG Policy scenario is expected to be lower cost than bookend scenarios

Incremental Total Resource Costs for Buildings (2045) ($2021 Billions per year)



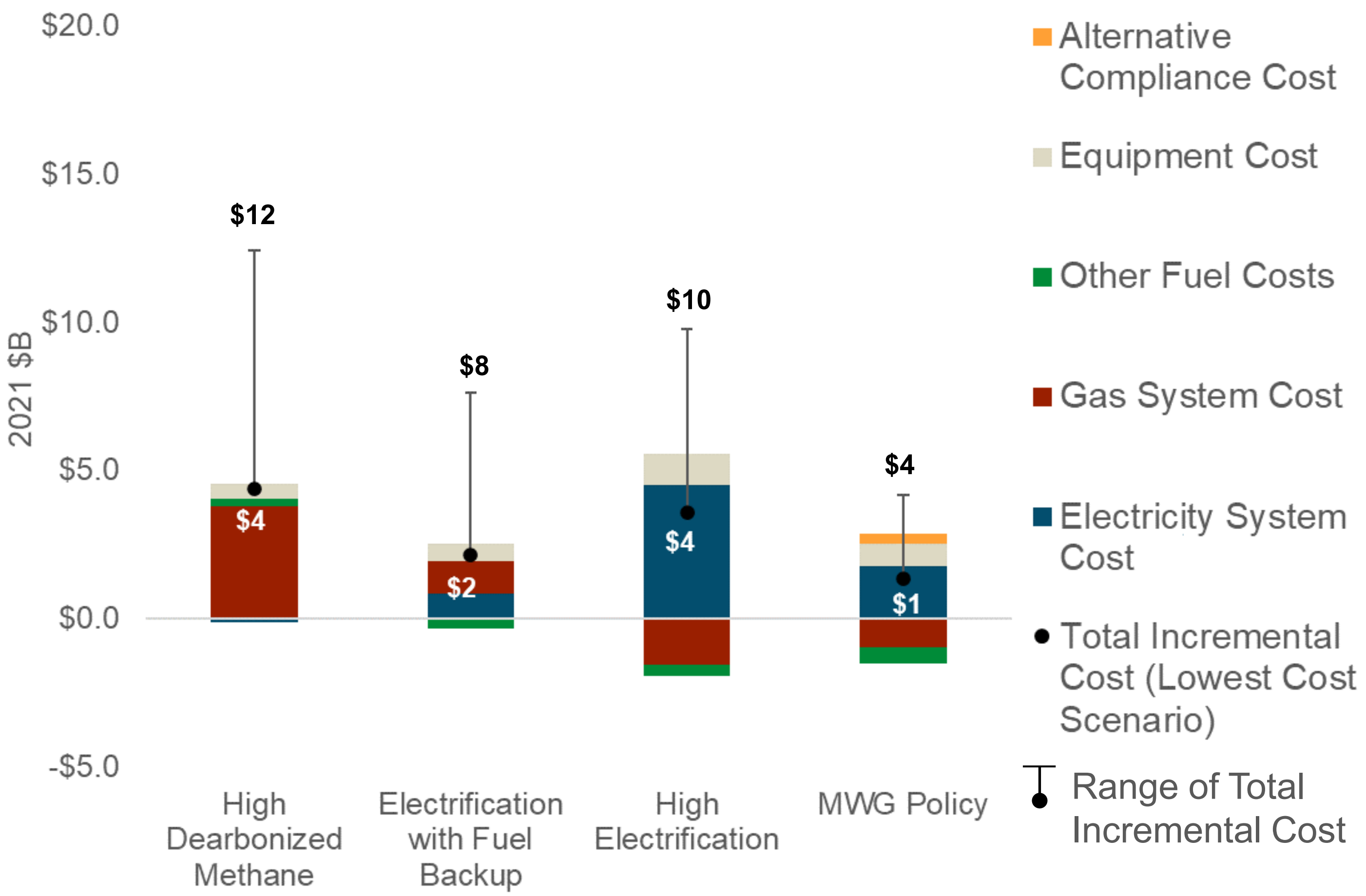
+ **The range of costs in the MWG policy scenario are mainly driven by the uncertainty with equipment cost, and are lower than the High Decarbonized Methane and High Electrification scenarios**

Sources & assumptions: These charts show incremental resource costs of the scenarios compared to the reference scenario.

Total cost range reflects assumptions regarding fuel costs, equipment cost, and heat pump installation practices

When excluding retrofit building shell improvement in all scenarios, MWG Policy Scenario is still expected to have lower cost than bookend scenarios

Incremental Total Resource Costs for Buildings (2045) ($2021 Billions per year) – *No Retrofit Shell Improvement*

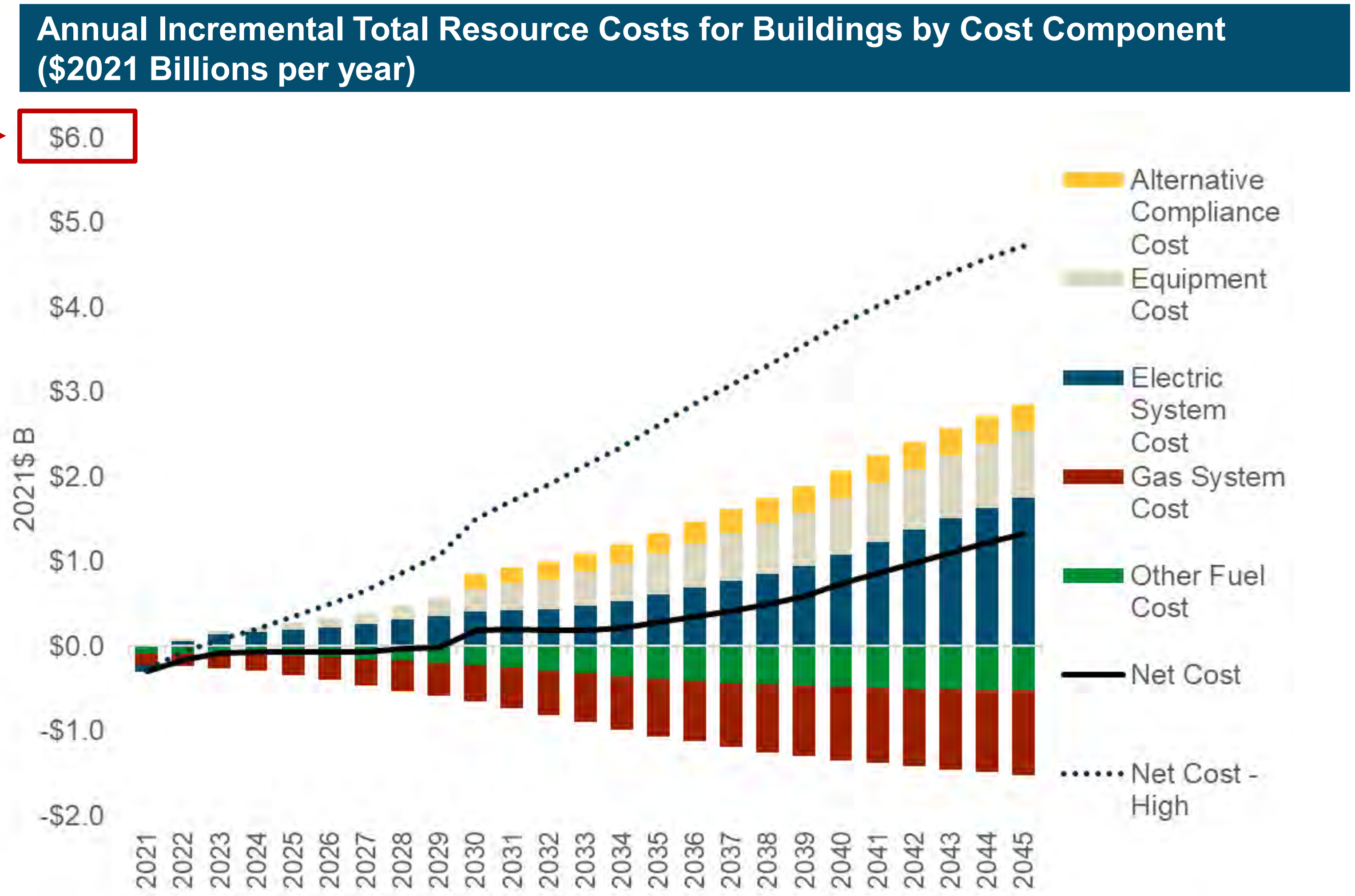


Sources & assumptions: These charts show incremental resource costs of the scenarios compared to the reference scenario. Total cost range reflects assumptions regarding fuel costs, equipment cost, and heat pump installation practices.

+ **The building shell measure considered in this study is illustrative of one type of deep shell retrofit, consisting of wall insulation, roof insulation, glazing, air-tightness, and heat recovery**
+ **This study finds that applying the deep shell retrofit to all buildings is expensive**
+ **E3 conducted a sensitivity analysis looking at the other bookend by removing the shell measure from all retrofit buildings**
+ **Without retrofit shell improvement, the range of costs in the MWG policy scenario is still lower than the High Decarbonized Methane and High Electrification scenarios**
+ **The perfect mix of shell measures will likely be in the middle of the two bookends considered in study**
  - It will vary by building type and customer preference in terms of cost effectiveness, the comfort level it brings and other factors

Annual Incremental Total Resource Cost MWG Policy Scenario without retrofit shell improvement

Note change of scale



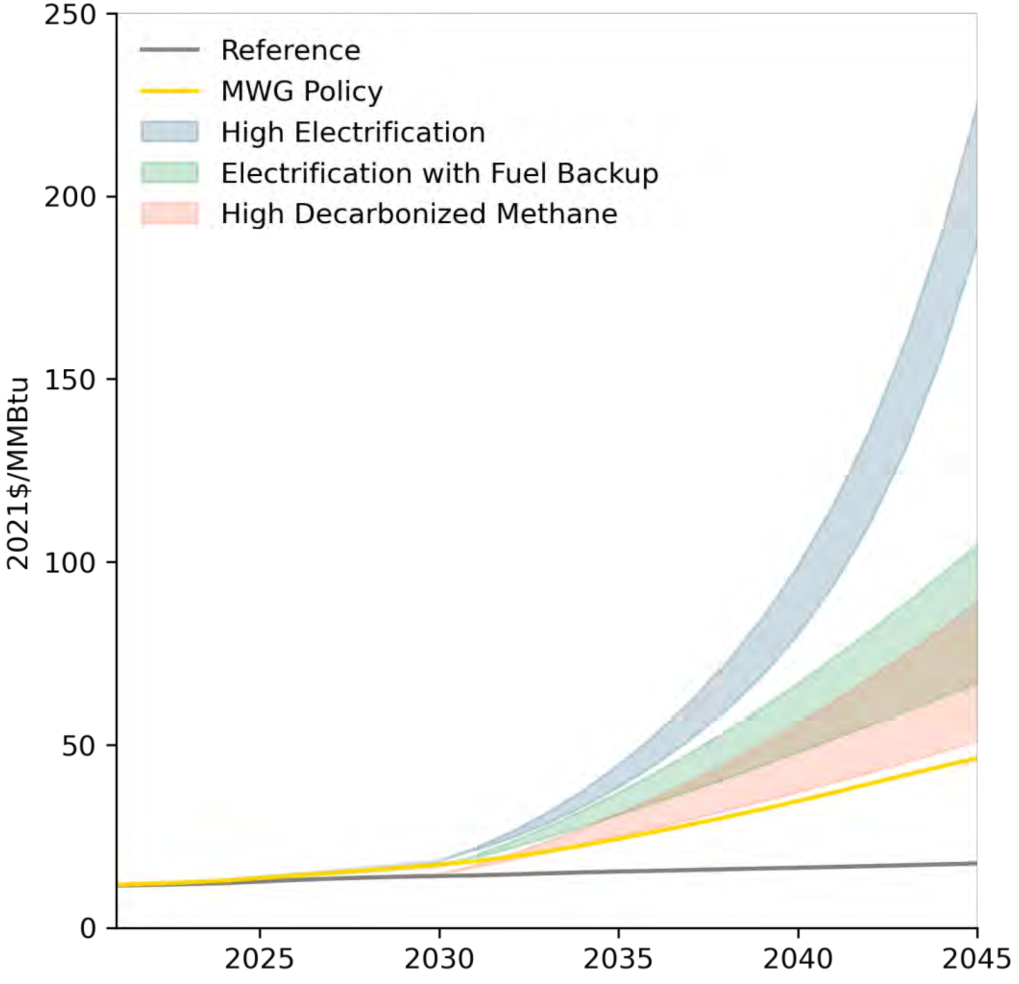
*Colored bars show cost break-down for the case with the lower-end of the net total resource cost range
**Illustrative results using annual incremental TRC from the MWG scenario with aggressive building shell improvement scaled by 2045 results from the "MWG Policy Scenario without retrofit shell improvement" sensitivity

Energy+Environmental Economics

Gas and Electric Rate Impact

MWG Policy scenario has the lowest gas rates due to not using low-carbon gas

Residential gas rates (2021$/MMBtu)

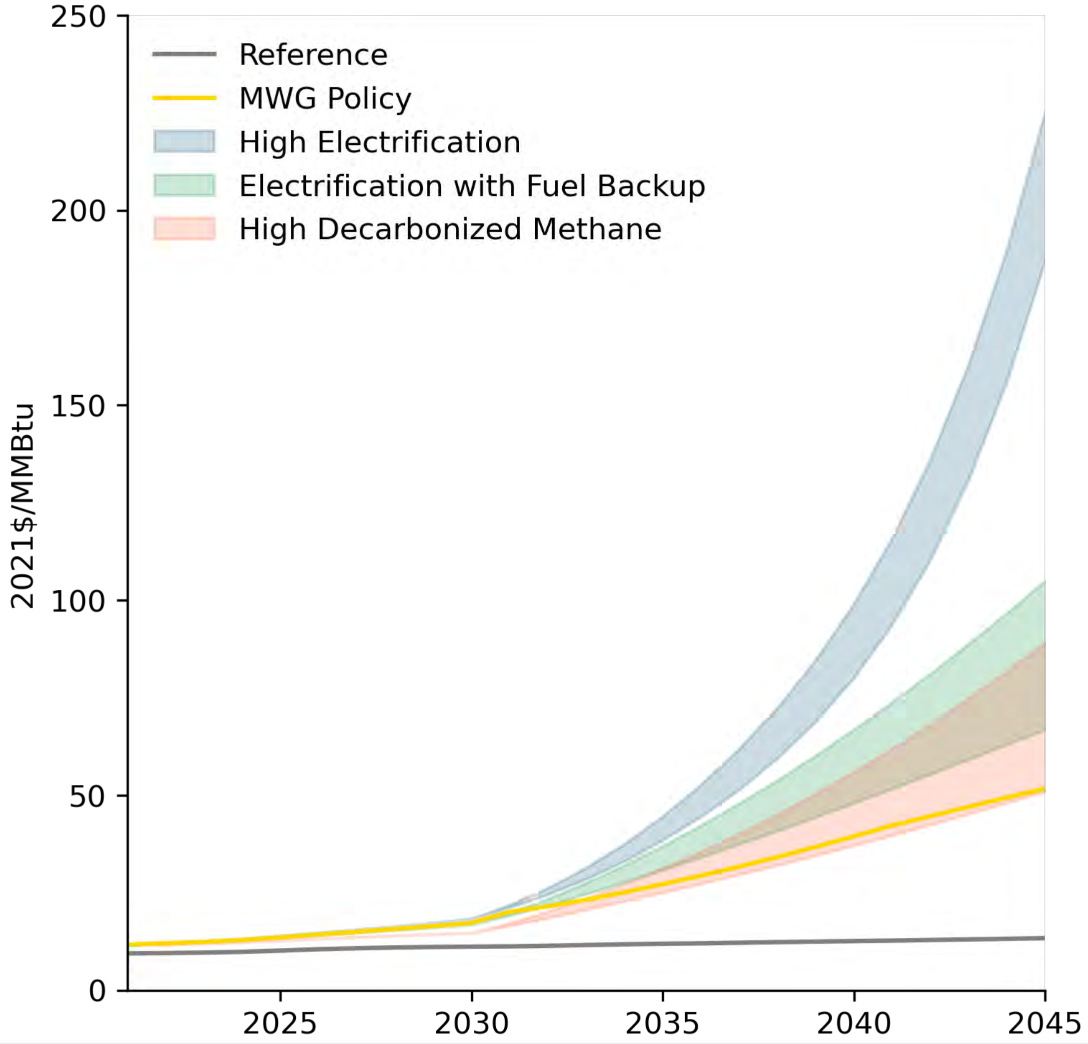


+ **High Electrification scenario** experiences a rapid rate increase driven by declining throughput despite lower total delivery and commodity costs
+ Rate increases in the **High Decarbonized Methane scenario** are driven primarily by the commodity cost for zero carbon fuel
+ **Electrification with Fuel Backup scenario** has higher gas rates than the High Decarbonized Methane scenario, due to its lower throughput and the resulting higher per MMBtu delivery cost
+ **MWG Policy scenario** has lower gas rates as this scenario continues to supply natural gas and delivery costs are primarily allocated to the commercial sector, but gas rates still goes up due to reduced throughput

*Range shown in figure reflects the commodity cost forecast uncertainty

Gas rates increase in the MWG Policy Scenario due to reduced throughput

Commercial gas rates (2021$/MMBtu)

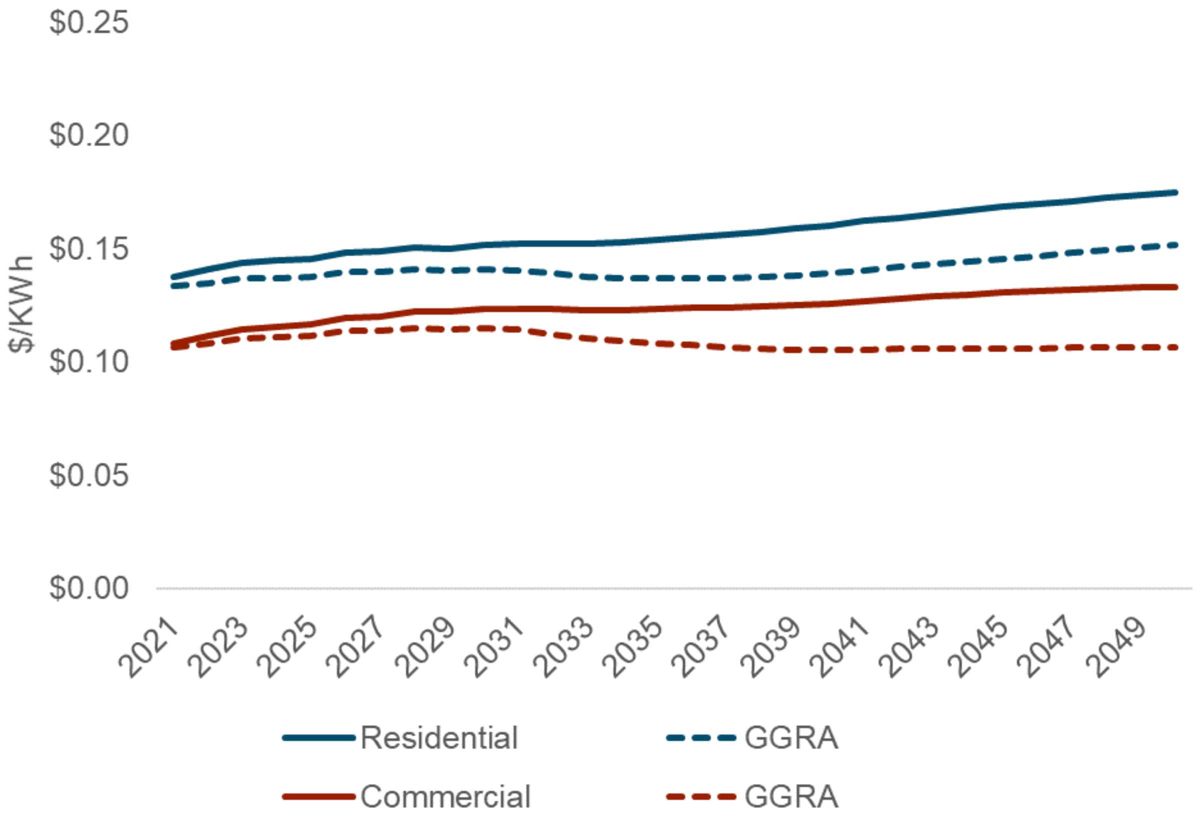


+ **Gas rates in the MWG Policy scenario still increases significantly due to reduced throughput, resulting in higher $/MMBtu delivery charge**

*Range shown in figure reflects the commodity cost forecast uncertainty

Electric rate impact

Average electric rates in the MWG Policy Scenario (2021$/kWh)

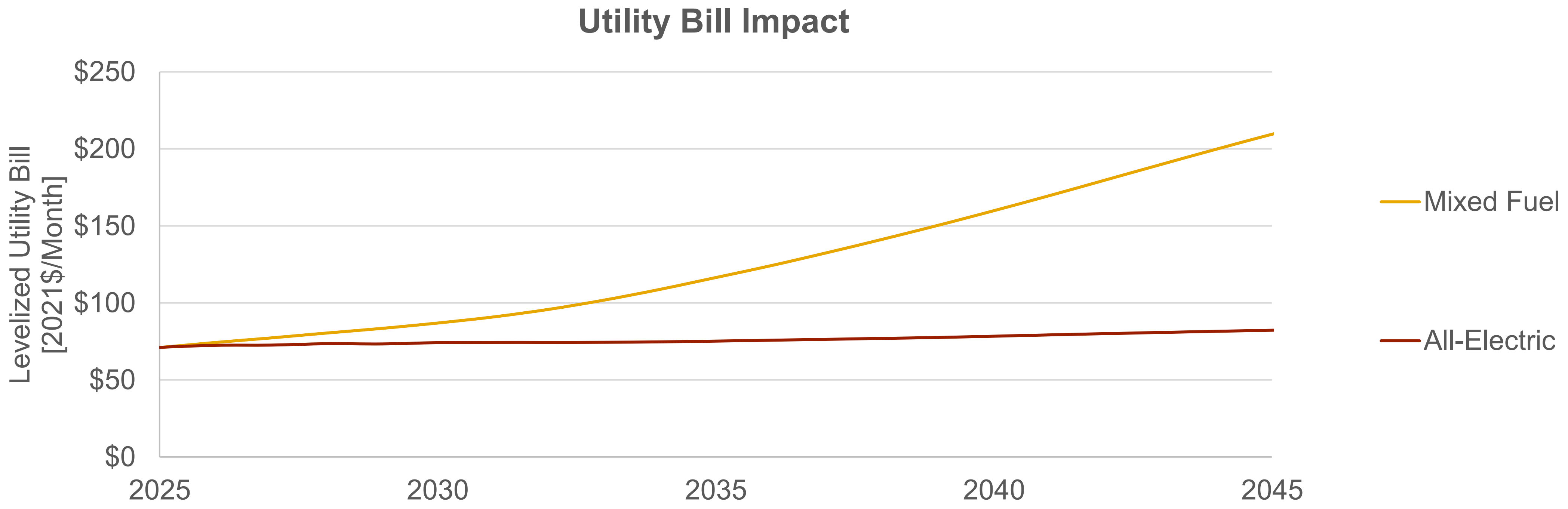


- **In the MWG policy scenario, residential and commercial electric rates are expected to rise over those projected in the GGRA due to increases in costs to serve peak heat loads from electrification.**
- **Rates are expected 25% lower than those in the High Electrification Scenario in 2045.**

Consumer Economics

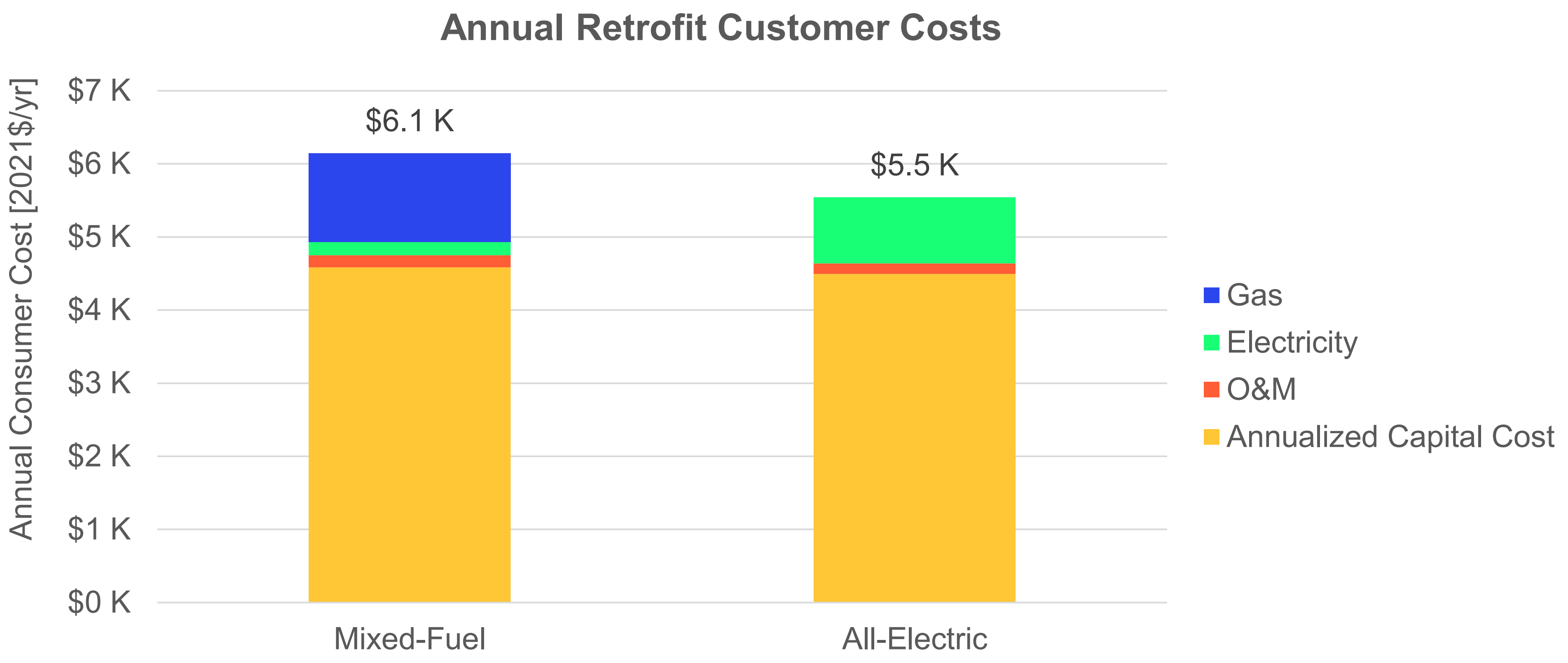
Illustrative customer bill impacts – residential single-family

+ **CAVEAT: These are not predictions of customer bills, but a representation of the potential dynamics under the current ratemaking model. These results indicate the potential equity and affordability challenges that will require systemic changes to the current dynamics.**



Electrifying space and water heating is expected to be a lower cost option for retrofit residential single-family buildings

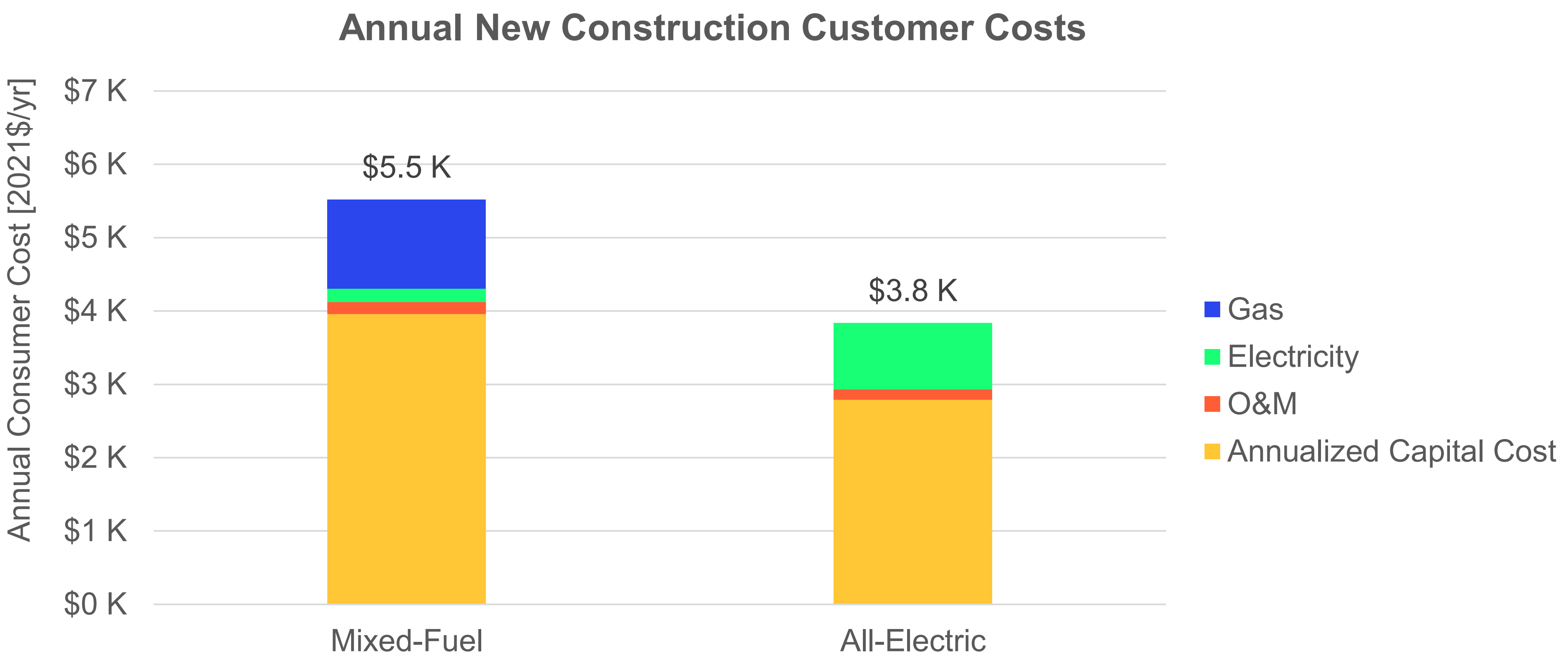
- **Single family customers can save both upfront capital and operating costs by retrofitting space and water heating from gas to heat pumps**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates

All-electric single-family design is expected to be the less expensive option

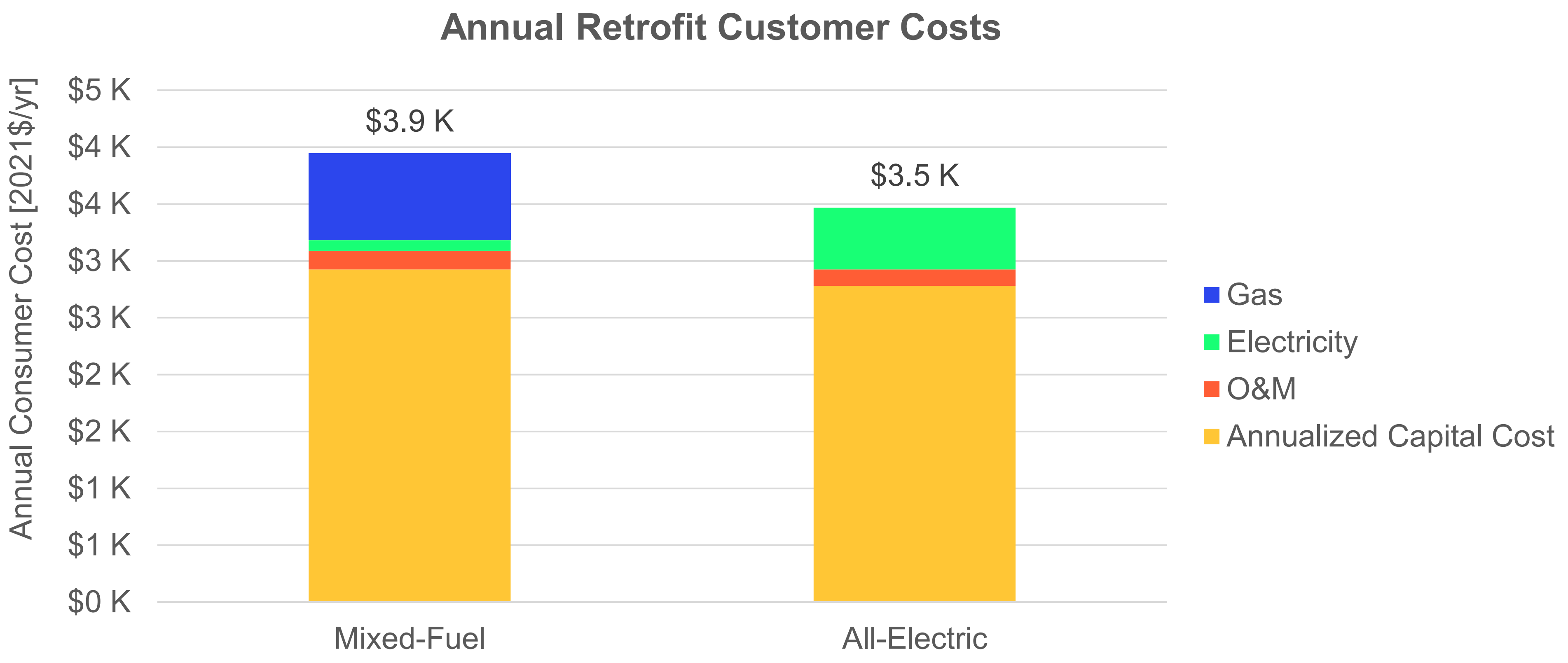
+ **All-electric new construction is cheaper than mixed-fuel new construction for single-family residential homes due to both lower capital (with avoided gas connection) and operating costs**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates

Multifamily residential retrofit consumer cost impact

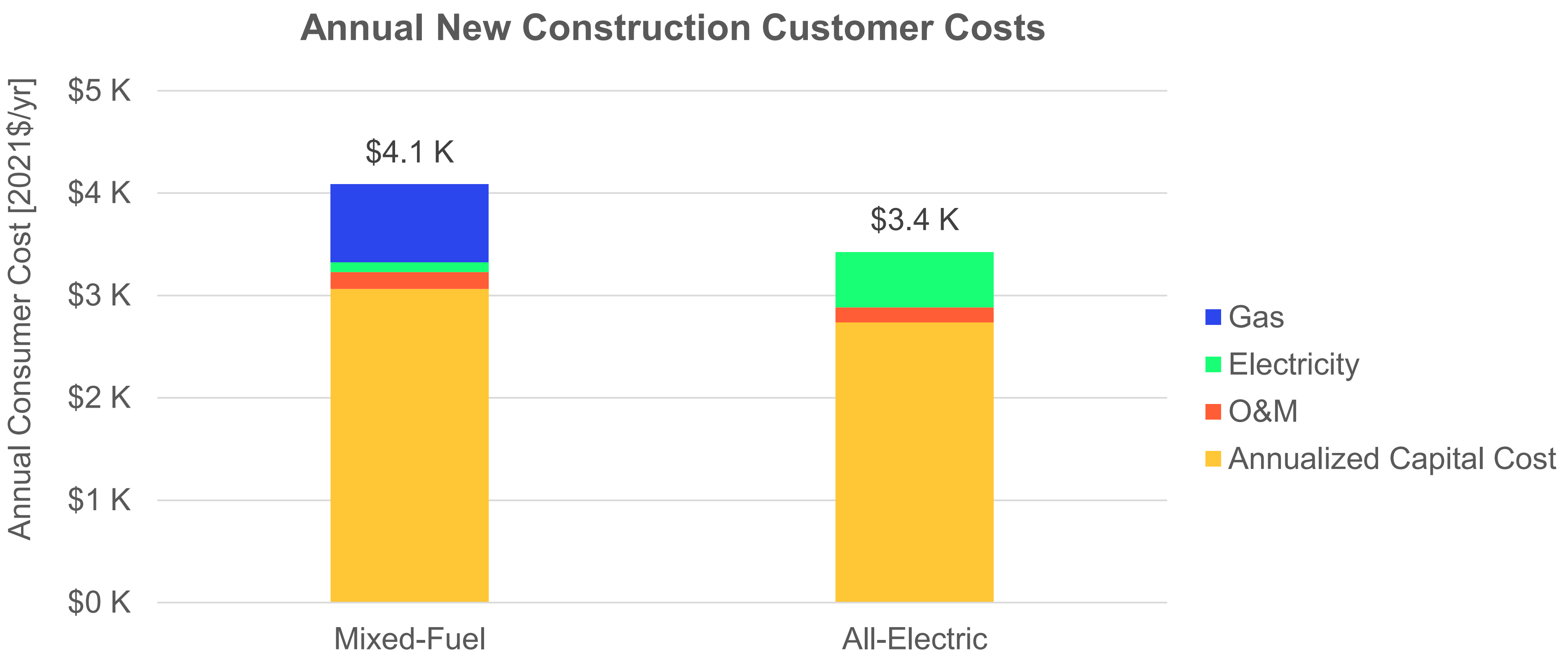
+ **Multi-family customers can save both upfront capital and operating costs by retrofitting space and water heating from gas to heat pumps**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates

Multifamily residential new construction consumer cost impact

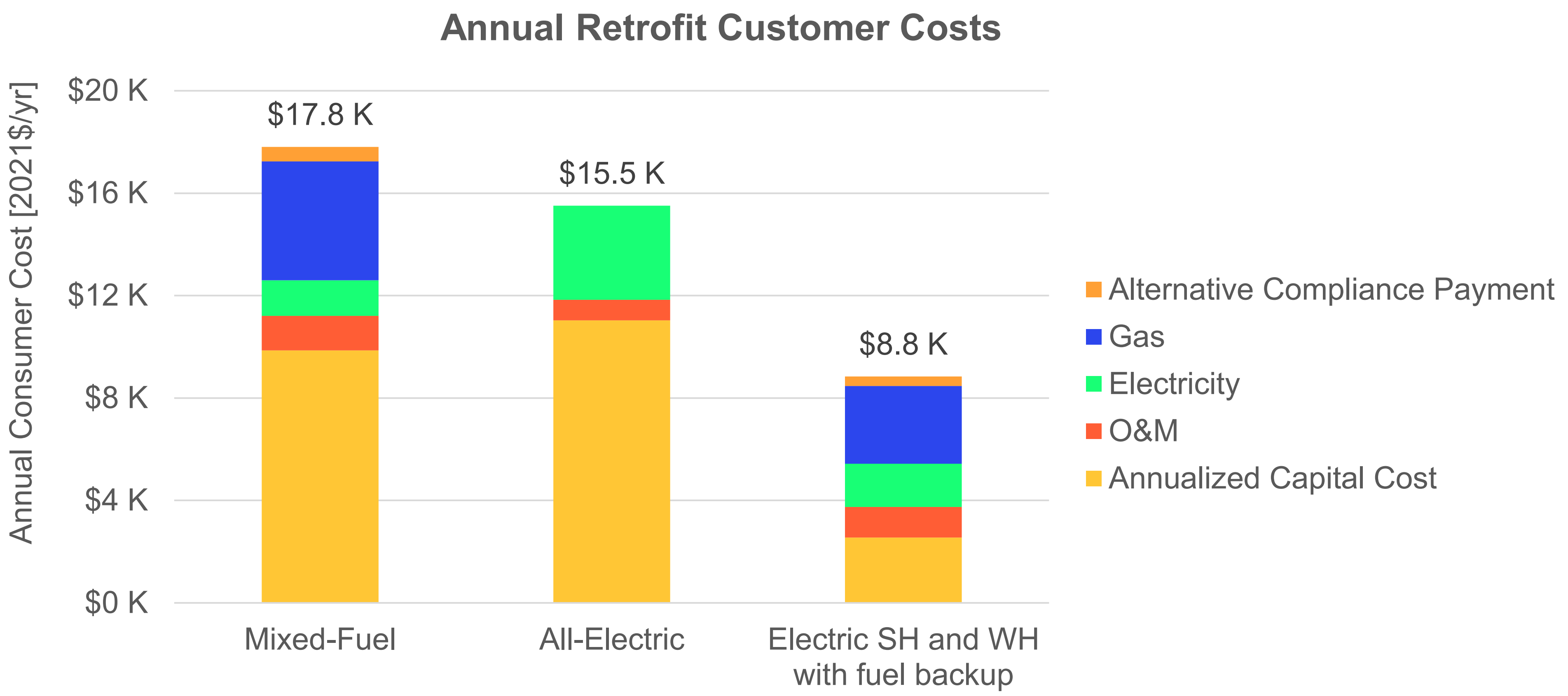
+ **All-electric new construction is cheaper than mixed-fuel new construction for multifamily residential homes due to both lower capital (with avoided gas connection) and operating costs**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates

Small commercial retrofit consumer cost impact

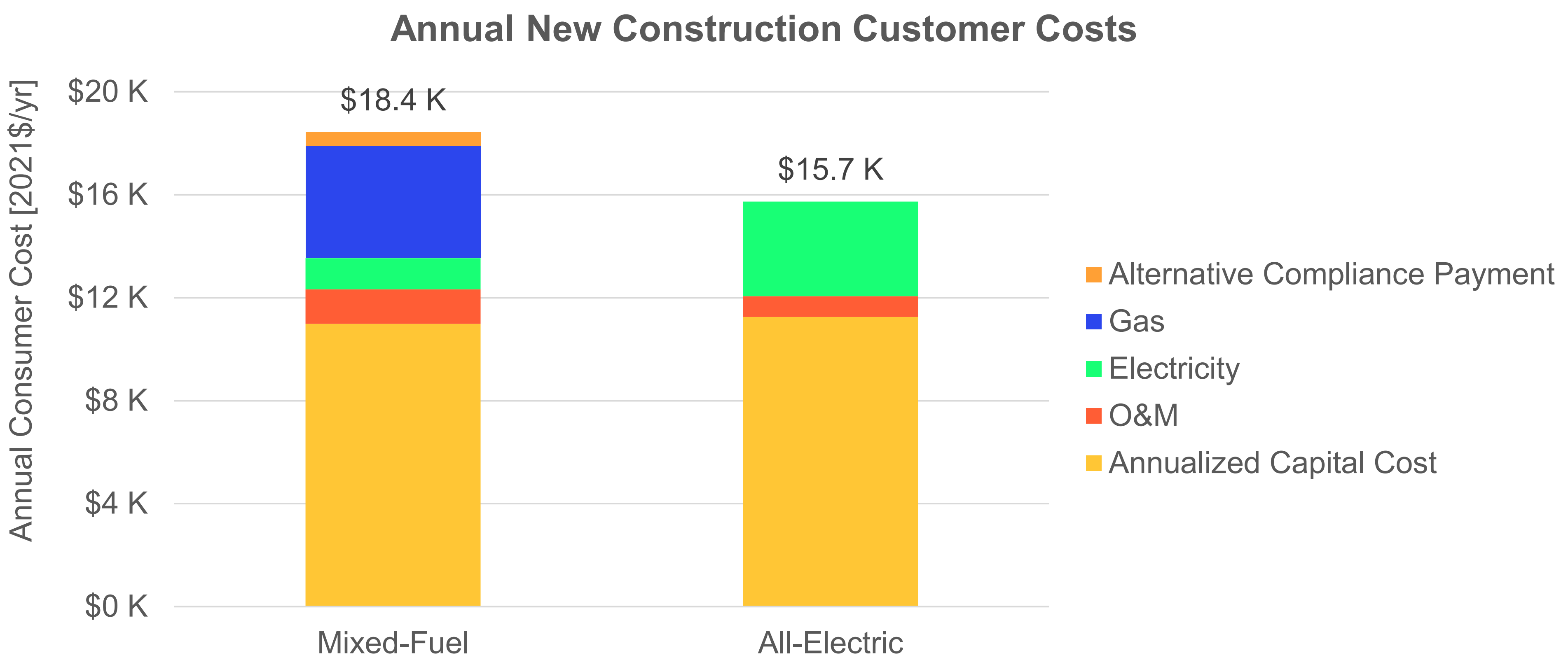
+ **"Hybrid" customers can save money by utilizing their existing fuel-based heating equipment to provide backup heating during coldest hours of a year, and by not having to upgrade building shells**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates

Small commercial new construction consumer cost impact

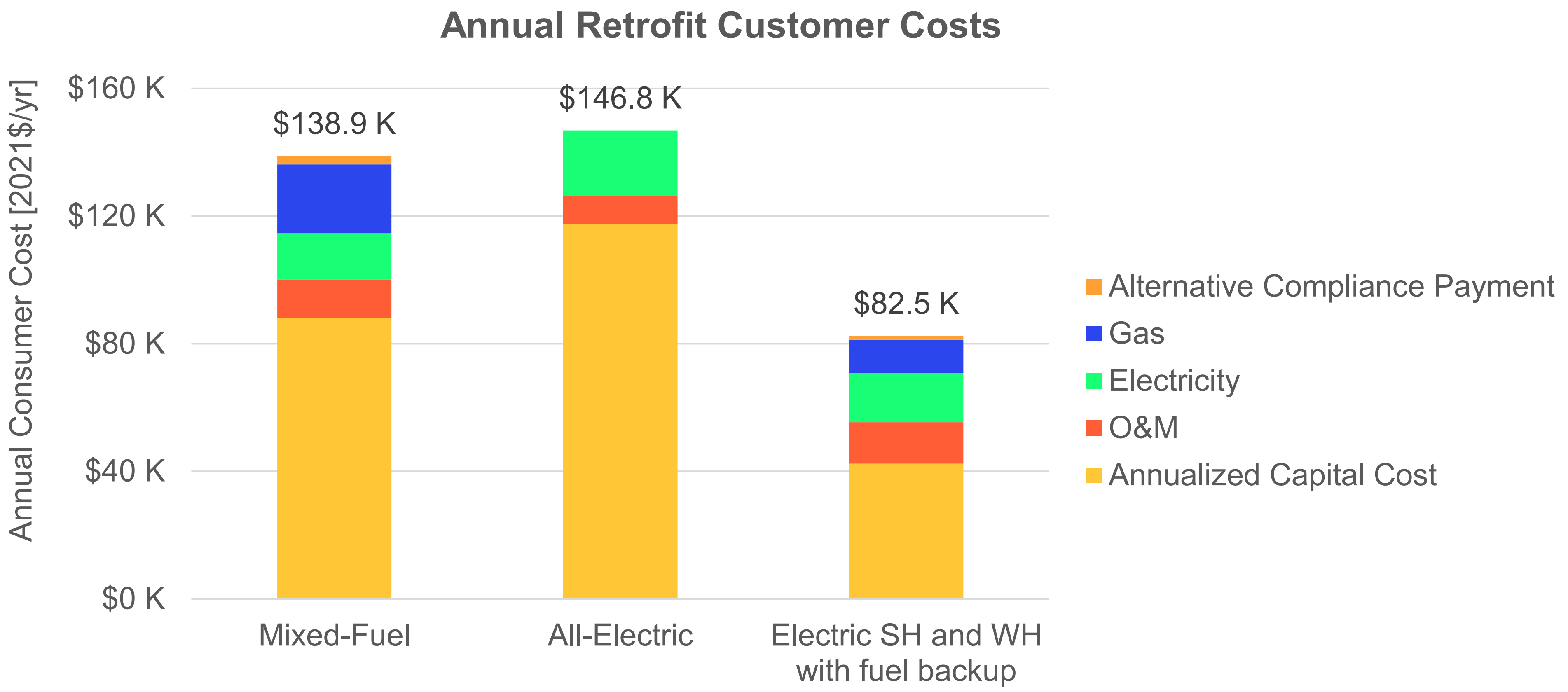
+ **All-electric new construction is cheaper than mixed-fuel new construction for small commercial buildings due to both lower capital (with avoided gas connection) and operating costs**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates

Large commercial retrofit consumer cost impact

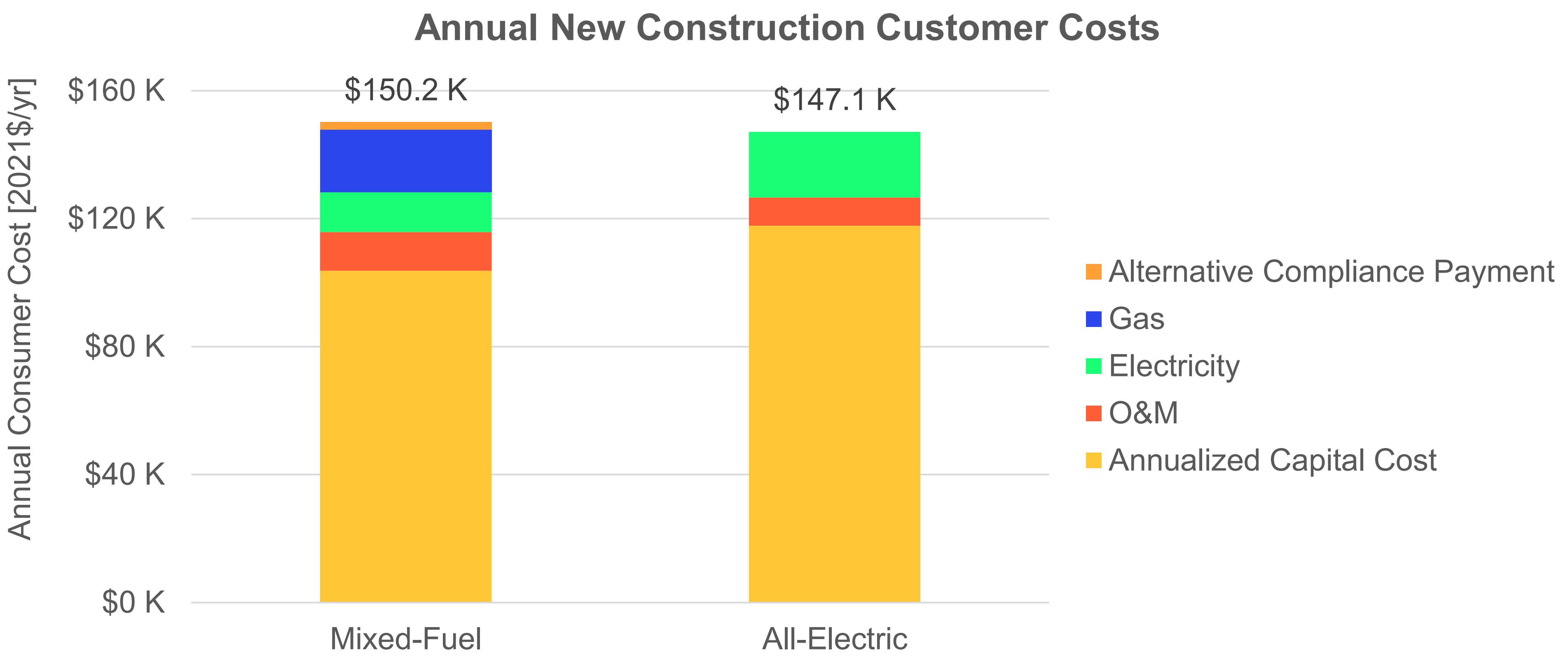
+ **"Hybrid" customers can save money by utilizing their existing fuel-based heating equipment to provide backup heating during coldest hours of a year, and by not having to upgrade building shells**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates

Large commercial new construction consumer cost impact

+ **All-electric new construction is cheaper than mixed-fuel new construction for small commercial buildings due to both lower capital (with avoided gas connection) and operating costs**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates

Summary of Findings

- **The MWG Policy Scenario has lower total system costs compared to the High Electrification and High Decarbonized Methane scenarios, assuming $100/MtCO2 alternative compliance costs for commercial buildings**
- **The MWG Policy Scenario has 0.6 MMt CO2e remaining emissions from residential buildings by 2045**
  - All remaining commercial sector emissions of 3.1 MMt CO2e is offset through alternative compliance payments
- **Residential customers can save costs by electrifying all building end-uses compared to using gas**
- **Commercial customers of retrofit buildings can save costs by employing a dual-fuel heating system with heat pumps providing majority of the heating need and fuel system providing backup during the coldest hours**
  - All-electric new commercial buildings is found to be less expensive compared to mixed-fuel new construction

Appendix

Energy+Environmental Economics

Scenario parameters

Sector	Parameter	Reference (2020 Reference Scenario from the GGRA work)	High Electrification	Electrification with Fuel Backup	High Decarbonized Methane
Buildings (residential + commercial)	Appliance efficiency	Current EMPOWER program • 50% of new sales of electric appliances are assumed to be efficient through 2023	Increased EE targets from utilities (consistent with GGRA Optimistic Sensitivity) • 100% new sales of electric appliances are assumed to be efficient through 2030 • 25% new sales of natural gas appliances by 2030	Renewed EMPOWER through 2030 (consistent with 2030 GGRA Plan) • 50% new sales of electric appliances are assumed to be efficient through 2030 • 25% new sales of natural gas appliances by 2030	Increased EE targets from gas utilities • 100% new sales of efficient natural gas appliances by 2030 • Electric appliance sales
	Building shell efficiency	Improved building shell sales in all residential new construction by 2030	Improved building shell sales in all new construction retrofit buildings by 2030 (An improved building shell reduces heating demand of a residential home by 29% and that of a commercial building by 34% relative to a typical existing building)	Reference	Improved building shell sales in all new construction and retrofit buildings by 2030
	Building electrification (heat pump sales share)	Linear adoption trend from historical sales of heat pumps (20% of space heater sales are heat pumps by 2045)	50% sales of electric heat pumps by 2025 (consistent with GGRA Optimistic Sensitivity), 100% sales by 2035 • 90% ccASHP • 10% GSHP (targeting medium/large rural homes currently on non-NG heating and campuses) • Electric resistance back-up	• 100% sales by 2035 of regular ASHP with gas furnace backup for non-new construction natural replacements • All-electric new construction with 90% ccASHP and 10% GSHP	• Reference for electric HPs • Gas in new construction
	Behavioral conservation and other non-stock sectors	Consistent with 2020 Reference	Consistent with 2030 GGRA Plan		
Decarbonized fuels	Fuel blend in 2050	100% natural gas and fuel oil	100% RNG (used mainly for remaining gas customers): • 93% RNG from biomass and Synthetic Natural Gas • 7% RNG with blended hydrogen blend	100% RNG (used mainly for gas backup): • 93% RNG from biomass and Synthetic Natural Gas • 7% RNG with blended hydrogen	100% RNG and renewable diesel: • 93% RNG from biomass and Synthetic Natural Gas • 7% RNG with blended hydrogen
Electricity	Electricity sector emission intensity	Consistent with 2020 Reference	Consistent with 2030 GGRA Plan (additional load will be met by a mix of renewable build and PJM imports; additional capacity need will be provided by a mix of renewables and storage with their corresponding ELCC values with the rest covered by new CTs build; this study will not identify the specific location of the new resource build, which could be in MD or other PJM states. For details, see the input assumptions deck)		

Climate Impact Assumptions

- **This study includes three illustrative effects to reflect climate impact**

1. **All buildings in Maryland will need air conditioning by 2045**
   - A/C saturation reaches 100% by 2045, increased from the current 94% penetration level
2. **Annual heating demand decreases over time, while annual cooling demand increases**
   - Annual heating demand decreases at -0.05% per year from now through 2045
   - Annual cooling demand increases at 0.71% per year from now through 2045
   - Both are based on EIA's projection from the 2020 Annual Energy Outlook
3. **Extreme summer weather will happen more frequently, while extreme winter weather still comes as often even though the average winter temperature increases**
   - We assume that a once-every-10-year (1-in-10) heat event will come every 2 years (1-in-2), and a 1-in-40 heat event becomes 1-in-10

Summary of key findings

Reducing direct building emissions to zero is feasible in all scenarios, but requires technology commercialization and accelerated implementation.

Electrification with Fuel Backup shows lowest overall costs while also reducing reliance on technologies that have not yet been widely commercialized or that are uncertain in their scalability

- **High Decarbonized Methane** requires large quantities of zero-carbon fuels, resulting in high incremental fuel costs with significant cost uncertainty depending on the commercialization of RNG
- **High Electrification** causes a Summer to Winter peak-shift and significant increase in peak electricity demand, resulting in high incremental electricity system costs

Consumers in **retrofit buildings** can save costs by employing a **dual-fuel heating system** with heat pumps providing majority of the heating need and fuel system providing backup during the coldest hours

All-electric new construction is found to be less expensive for consumers considering all costs including equipment and fuel costs compared to mixed-fuel new construction that uses fuels for heating

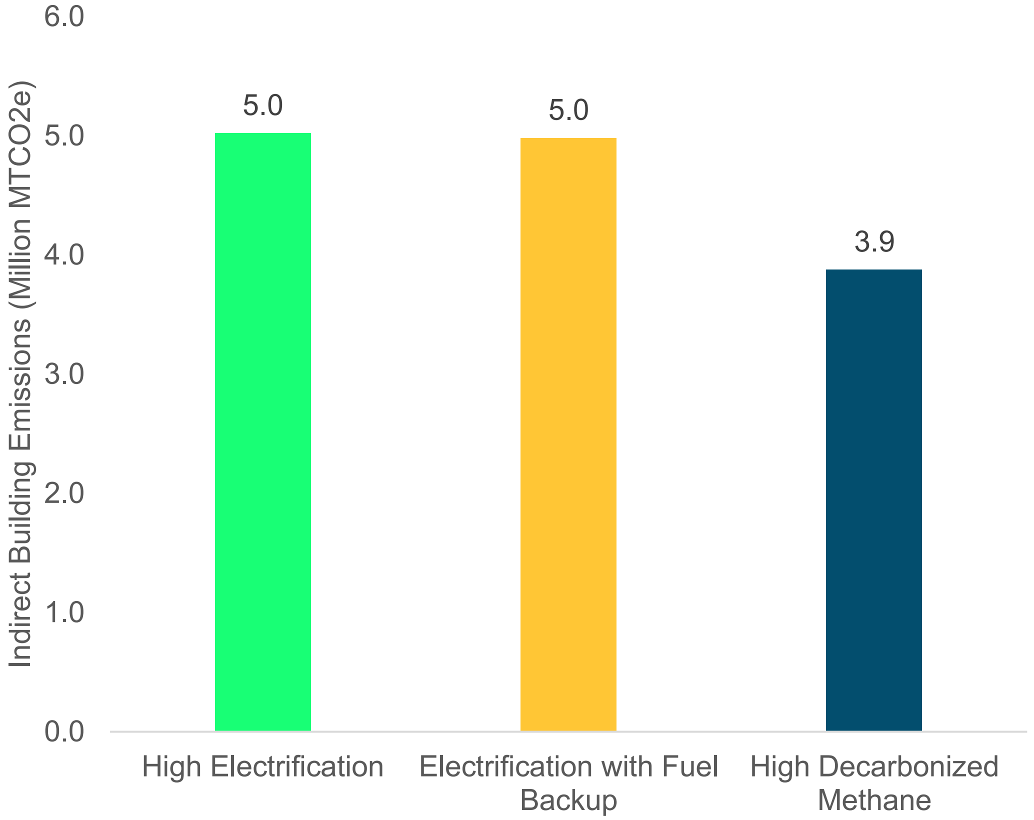
Achieving the Electrification with Fuel Backup scenario would require careful policy design that incentivizes consumers to employ dual-fuel heating systems

Costs of gas increase in all scenarios as a result of zero-carbon fuels and higher delivery costs (due to lower gas demand in the electrification scenarios); emphasis on mitigating the energy burden with customers **'staying behind'** is important.

Indirect emissions from upstream electricity generation still remain by 2045

+ **Indirect emissions from upstream electricity generation still remain by 2045**
  - Using GGRA assumptions that by 2045 all in-state generations are carbon-free but there are still GHG emissions associated with PJM imports

Indirect building GHG emissions from upstream electricity generation in 2045 (MMtCO2e per year)



*Upstream emissions electricity generation for information purposes. This does not include fugitive emissions from upstream natural gas extraction.

Climate Impact Assumptions

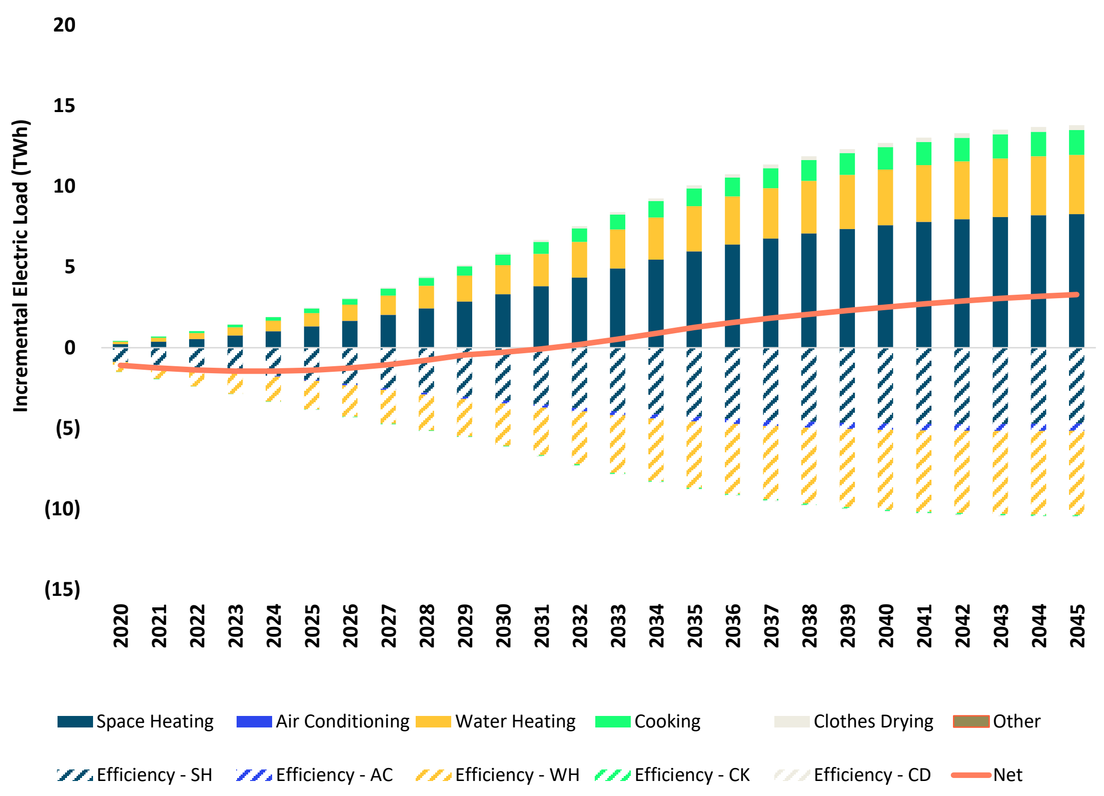
- **Three illustrative effects due to climate change were incorporated into this analysis**
  1. **All buildings in Maryland will need air conditioning by 2045**
     - A/C saturation reaches 100% by 2045, increased from the current 94% penetration level
  2. **Annual heating demand decreases over time, while annual cooling demand increases**
     - Annual heating demand decreases at -0.05% per year from now through 2045
     - Annual cooling demand increases at 0.71% per year from now through 2045
     - Both are based on EIA's projection from the 2020 Annual Energy Outlook
  3. **Extreme summer weather will happen more frequently, while extreme winter weather still comes as often even though the average winter temperature increases**
     - We assume that a once-every-10-year (1-in-10) heat event will come every 2 years (1-in-2), and a 1-in-40 heat event becomes 1-in-10

Energy+Environmental Economics

Detail Scenario Results

Incremental Electric Load: High Electrification

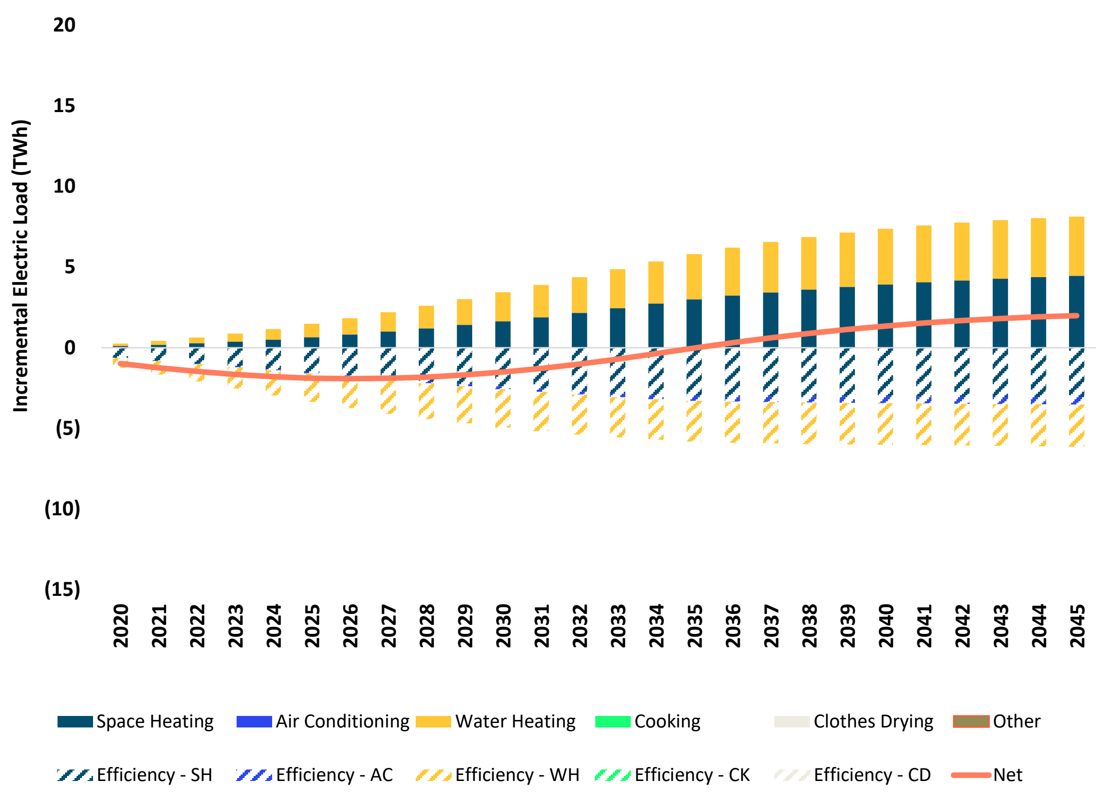
High Electrification



- **Electric devices reach 100% sales share by 2045**
  - Customers adopt electric air- or ground-source heat pumps
- **Net load increase through 2050**
  - Large **growth** in incremental load from fuel switching
  - Moderate **reduction** in incremental load from shift to high-efficiency

Incremental Electric Load: Fuel Backup

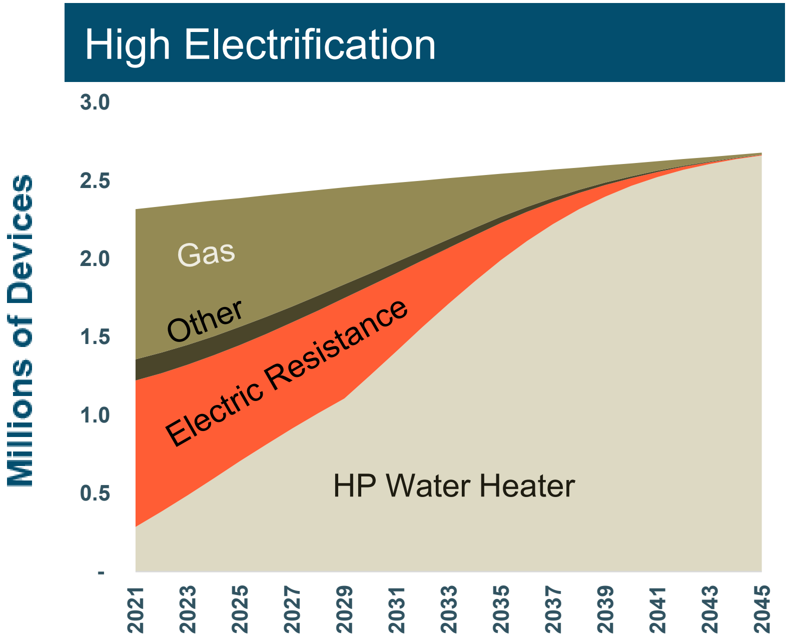
Electrification with Fuel Backup

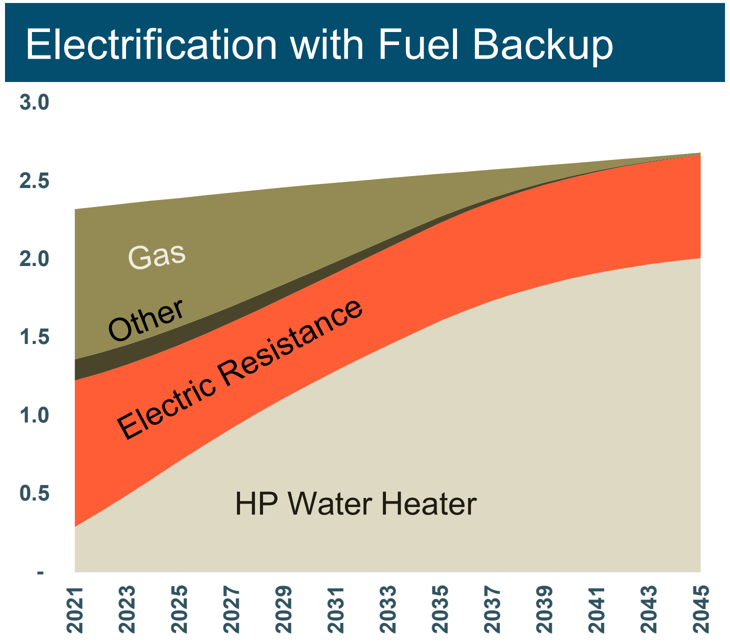


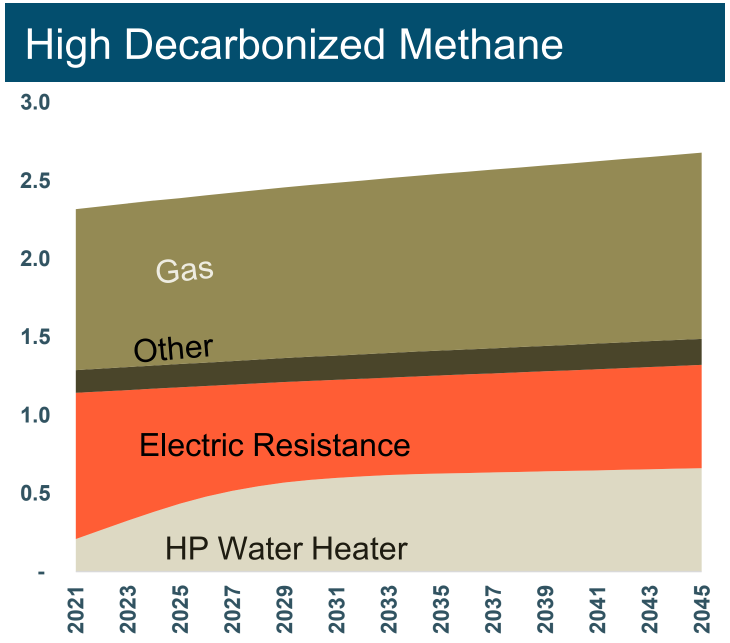
- **Electric devices reach 100% sales share by 2045**
  - Most existing gas customers upgrade to dual-fuel heat pumps with gas backup
- **Load decreases through 2035 and increases from 2036 to 2045**
  - Efficient electrification initially outweighs load growth from fuel switching
  - Net load growth in later years with deep electrification

Water heating end-uses are all electrified by 2045 in the two electrification scenarios

+ **All fuel-based water heating end-uses switch to heat pump water heaters in the High Electrification and Electrification with Fuel Backup scenarios**
+ **Electric resistance currently accounts for about 40% of water heating devices**
  - EMPOWER program incentives continue after 2023





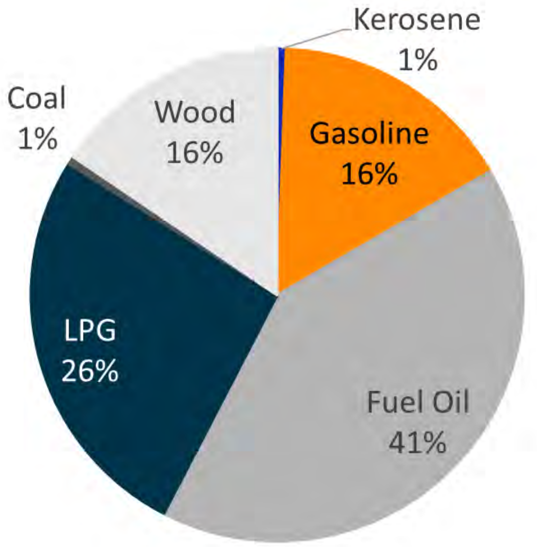


* "Other" water heating devices mainly include fuel oil and LPG-based furnaces and boilers

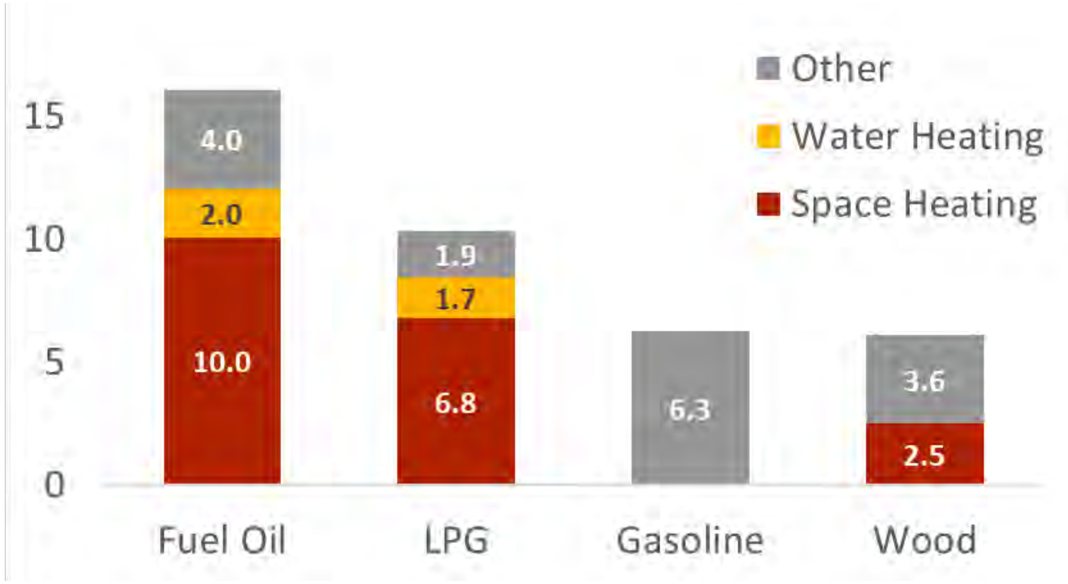
Other building fuel demand mainly consists of liquid fuels, such as fuel oil, LPG and gasoline

- Other building fossil fuels are mainly used for heating by customers that do not have natural gas connections
- There are also miscellaneous usage of these liquid fuels, mainly in the commercial sector, such as gasoline- or diesel-powered electricity generators

Current Mix of Other Fuel Demand in Maryland Buildings

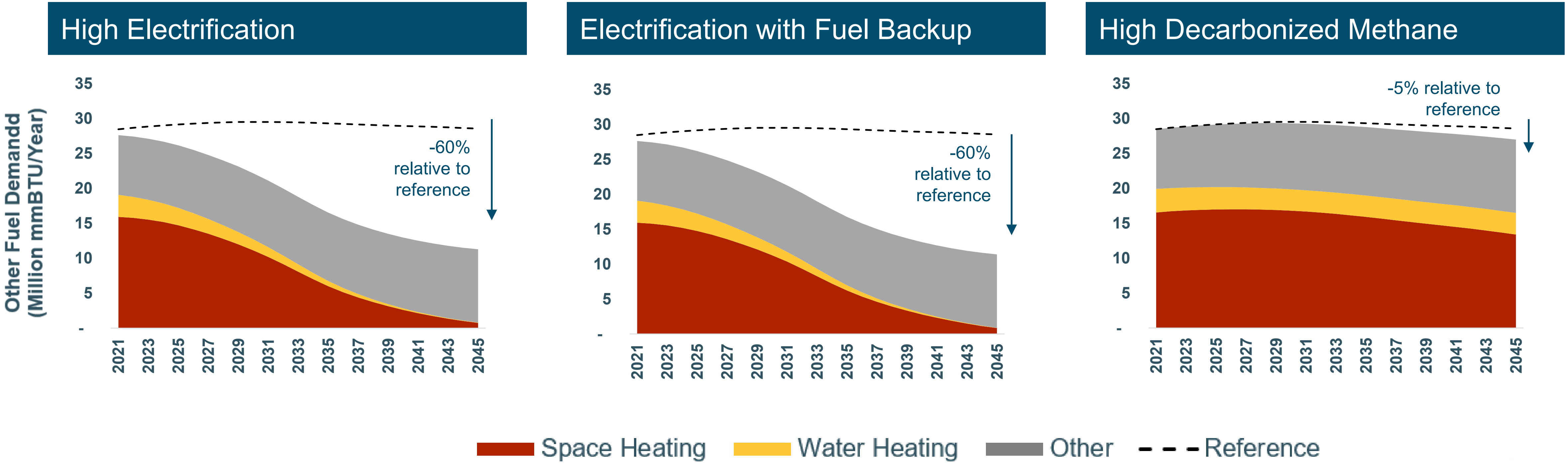


Other Fuel Demand by Fuel and End-use (TBtu)



Other fuel demand declines due to energy efficiency and fuel switching, and are all converted to biofuels by 2045

- **Usage of non-gas fuels (mostly fuel oil and liquid propane gas) decreases in all scenarios**
  - Fuels are displaced as customers electrify in the High Electrification and Electrification with Fuel Backup scenarios
  - Fuel demand decreases in the High Decarbonized Methane scenario due to efficient device adoption and building shell improvement
- **By 2045, fossil fuels used for remaining end uses are all converted to biofuels**



RNG Costs

Different types of decarbonized gas considered

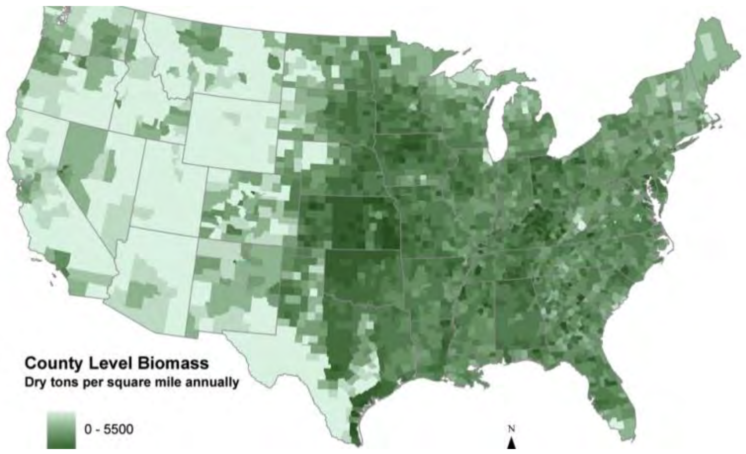
+ **E3 considers a variety of decarbonized gas sources and has compiled a supply curve based on estimates of the availability and costs of each source.**

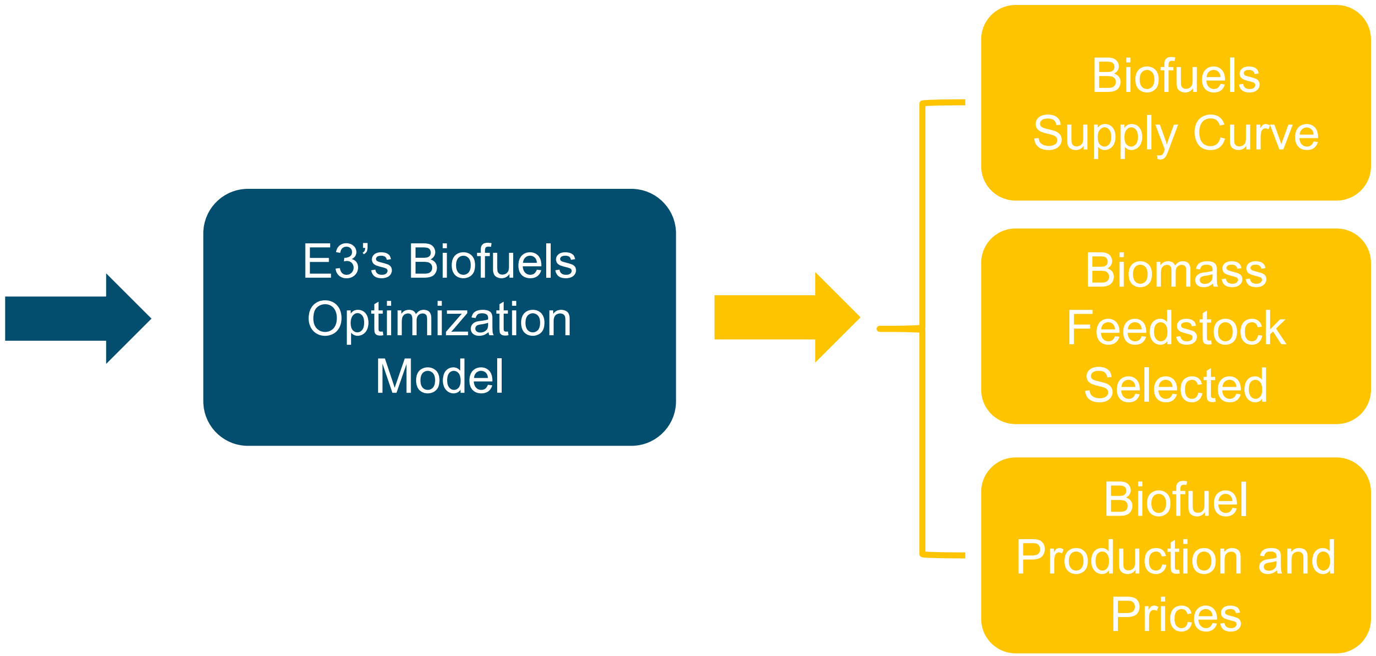
Waste biogas	Gasification of biomass	Hydrogen	Synthetic Natural Gas (SNG)
Sources: Municipal waste, manure, landfill gas	**Sources:** Agriculture and forest residues, and purpose grown crops, e.g. switchgrass;	**Sources:** Electrolysis + zero-carbon electricity or Steam Methane Reforming of natural gas with Carbon Capture and Sequestration (not considered in this study)	**Sources:** Renewable hydrogen + CO2 from biowaste (bi-product of biofuel production) and/or direct air capture (DAC)
Constraints: Very limited supply	**Constraints:** Limited supply and competing uses for biofuels	**Constraints:** Limited pipeline blends (7% by energy) without infrastructure upgrades, cost	**Constraints:** Limited commercialization, low round-trip efficiency, high cost

Biofuels Supply and Cost Estimates

- **E3's Biofuels Model optimizes the allocation of scarce biomass and identifies a lowest-cost portfolio of biofuels**
- **The model outputs quantity of production by fuel, their production costs and a market clearing price for each fuel**
- **E3 derives biomass supply estimates from the US Department of Energy *Billion Ton Report***

Biomass Supply based on the DOE Billion Ton Report

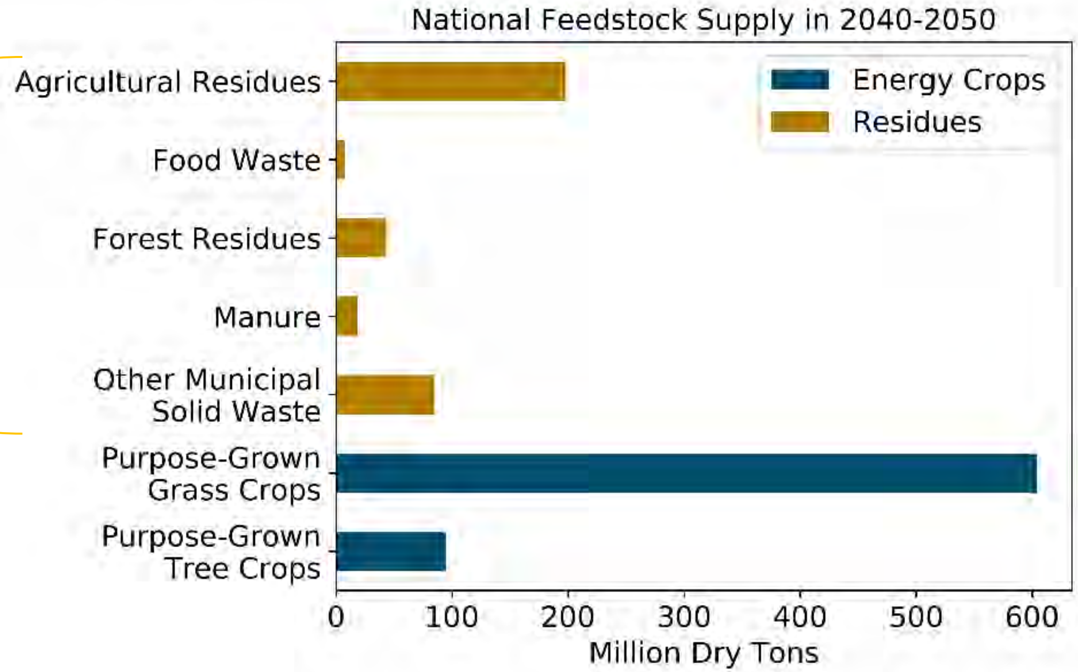




Feedstock Potential

- **The Billion Ton Study includes two major categories of feedstock:**
  - **"Residues" include feedstocks such as agricultural residues, forest thinnings, and food waste**
  - **"Energy Crops" include dedicated land to grow high-energy crops or new forests for conversion to biofuels. *These have been excluded for this analysis due to land-use concerns***

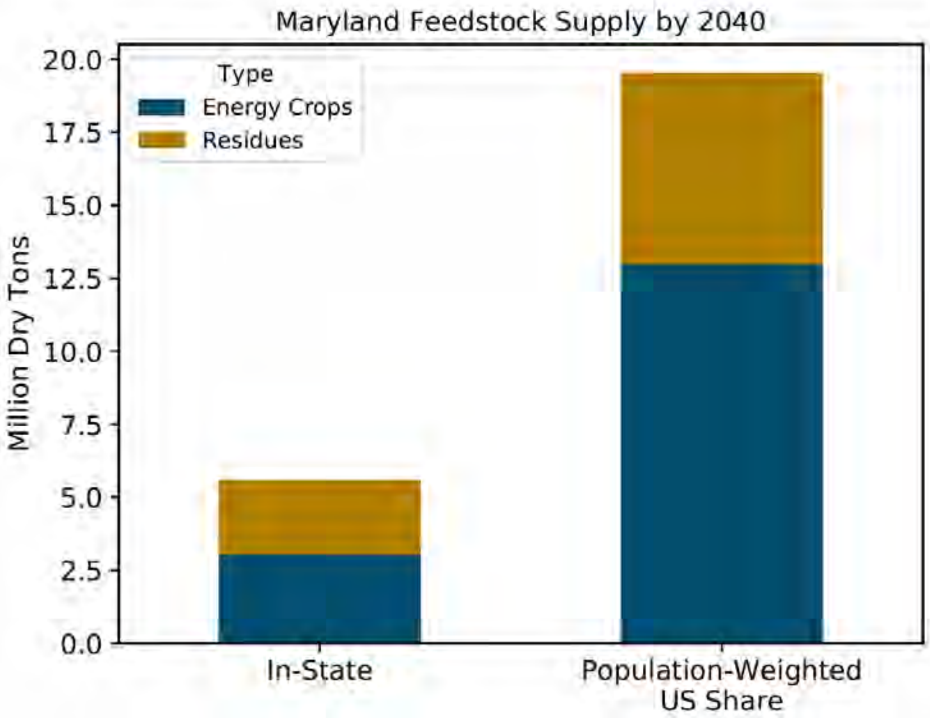
Categories Included in this analysis



Source: DOE, 2016. Billion Ton Update

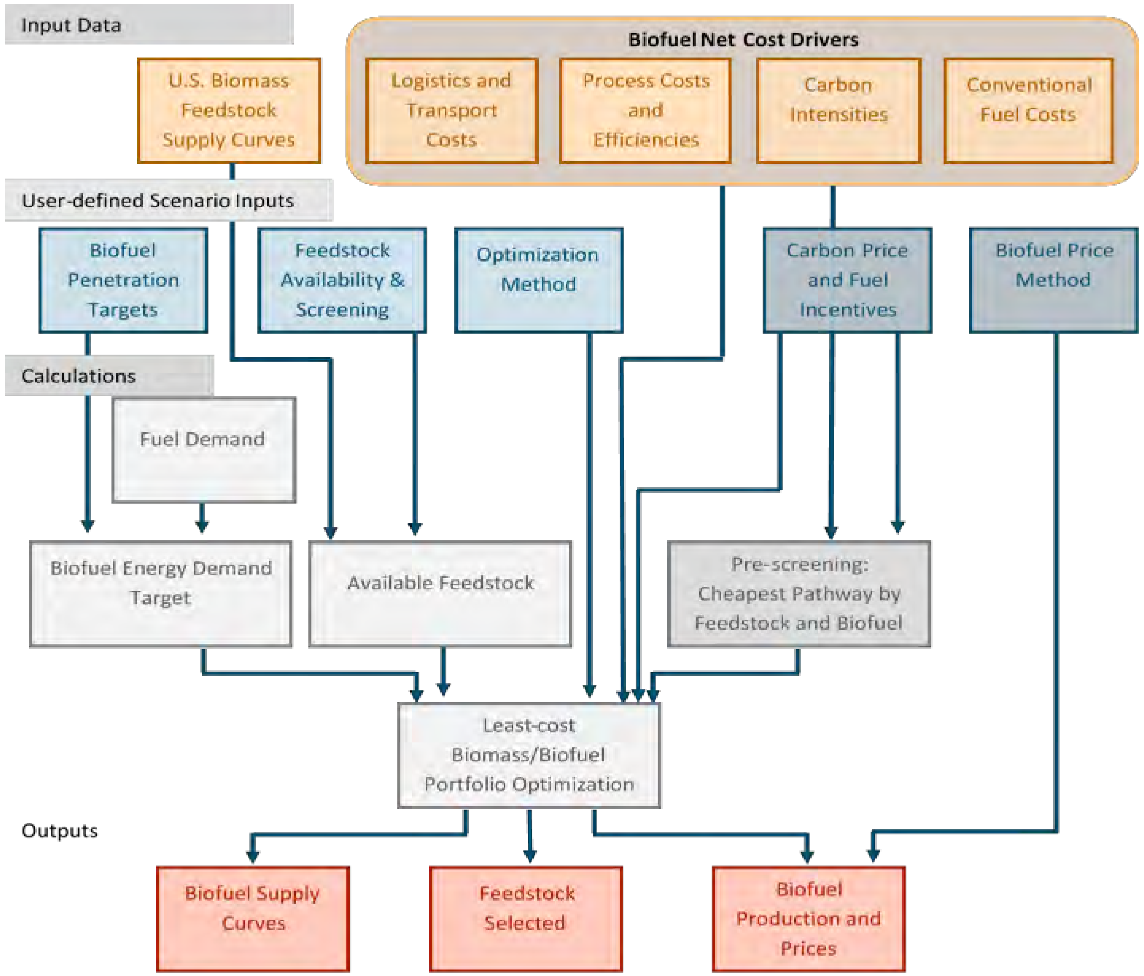
Maryland Biomass Feedstocks

+ **Maryland has limited in-state biomass resource potential**
+ **Using the population-weighted share of the US supply (1.9%), MD has access to more than 2x the in-state potential of residues and wastes**



Source: DOE, 2016. Billion Ton Update

E3 Biofuels Optimization Model



E3's Biofuels Model optimizes the allocation of scarce biomass to decarbonize fuels.

Given liquid and gaseous demands, it identifies a portfolio of fuels with the highest "bang" per GHG mitigation "buck"

The model returns biofuels produced by fuel, their production costs and a market clearing price for each fuel

Biomass Gasification: Process Cost Assumptions

- **Costs developed by University of California, Irvine (UCI) based on literature review of actual gasification plant costs, with an assumed learning rate over time**
- **Interconnection costs are implicitly included in the assumed capital costs**

	2020	2025	2030	2035	2040	2045	2050
Gasification plant capital costs (2016$/kWth)*	1400	1134	927.6	834.8	761	719	695
Fixed O&M (2016$/kW-yr)	59	47.8	39.1	35.2	32.1	30.3	29.3
Variable O&M (2016$/MWh)	13	10.5	8.6	7.8	7	6.7	6.5
Resulting process costs for gasification of corn stover (2016$/dry ton)**	153.1	125.3	103.1	93.1	85.1	80.6	78.1

*Interconnection costs are included in gasification plant capital costs and average at $2.3 million in 2020 (capital costs only) with a 12% learning rate, based on a 50 MW plant (cost developed by UCI and outlined in Appendix C of the CEC Study on The Challenge of Retail Gas in California's Low Carbon Future.

**Process costs are different for each feedstock, as they are dependent on the HHV for the specific conversion pathway. Corn stover is used as an example, as it makes up the majority of available MN biomass in the DOE Billion Ton Study. The costs for all pathways are shown on the next slide.

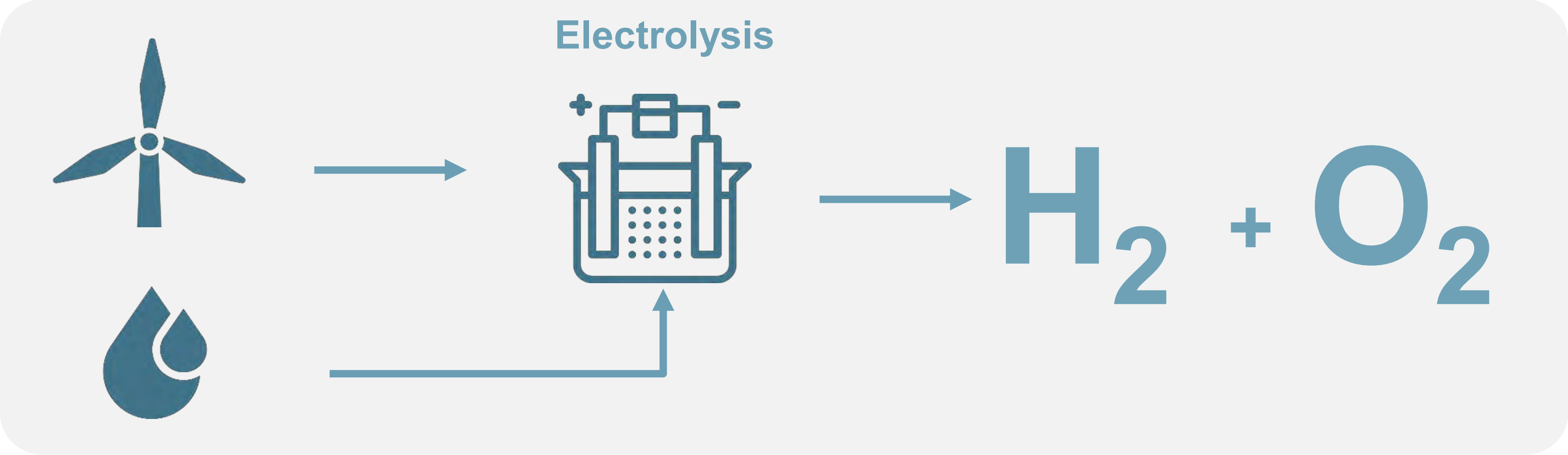
Full gasification process cost assumptions

Gasification process costs by feedstock (2016$/dry ton)

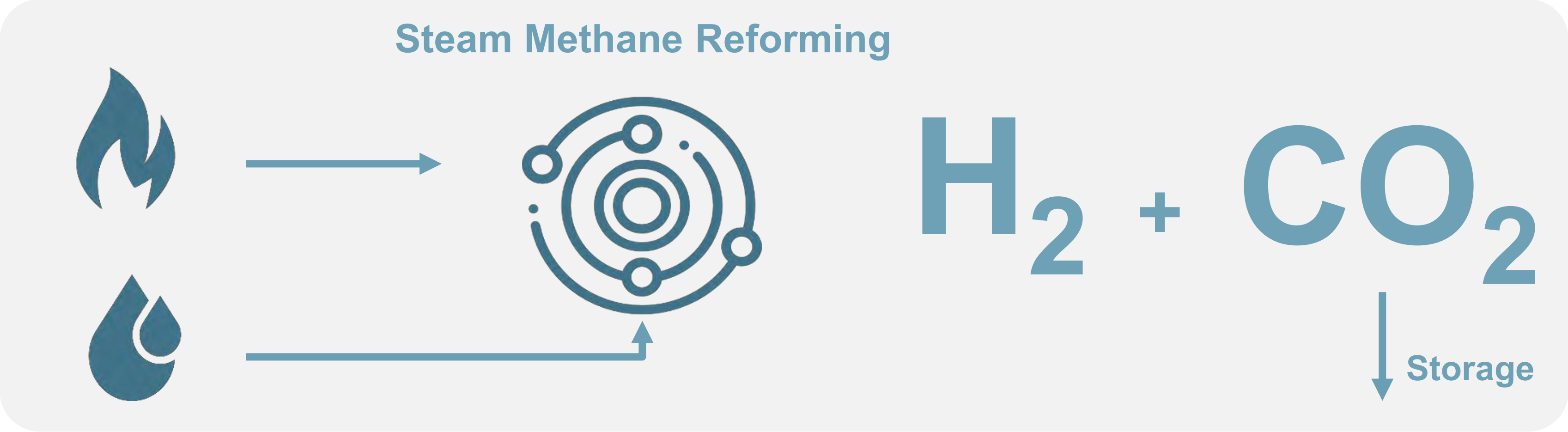
	2020	2025	2030	2035	2040	2045	2050
Barley straw	$ 158.09	$ 129.36	$ 106.46	$ 96.10	$ 87.88	$ 83.26	$ 80.65
CD waste	$ 157.98	$ 129.27	$ 106.39	$ 96.04	$ 87.82	$ 83.21	$ 80.59
Corn stover	$ 153.10	$ 125.28	$ 103.10	$ 93.07	$ 85.10	$ 80.63	$ 78.10
Hardwood, lowland, residue	$ 165.90	$ 135.75	$ 111.72	$ 100.85	$ 92.22	$ 87.38	$ 84.63
Hardwood, upland, residue	$ 165.90	$ 135.75	$ 111.72	$ 100.85	$ 92.22	$ 87.38	$ 84.63
MSW wood	$ 162.24	$ 132.76	$ 109.26	$ 98.63	$ 90.19	$ 85.45	$ 82.76
Mixedwood, residue	$ 165.90	$ 135.75	$ 111.72	$ 100.85	$ 92.22	$ 87.38	$ 84.63
Noncitrus residues	$ 152.76	$ 125.01	$ 102.89	$ 92.88	$ 84.93	$ 80.47	$ 77.95
Other	$ 144.16	$ 117.97	$ 97.09	$ 87.64	$ 80.15	$ 75.94	$ 73.55
Other forest residue	$ 152.76	$ 125.01	$ 102.89	$ 92.88	$ 84.93	$ 80.47	$ 77.95
Paper and paperboard	$ 179.05	$ 146.51	$ 120.57	$ 108.84	$ 99.53	$ 94.30	$ 91.34
Primary mill residue	$ 172.78	$ 141.39	$ 116.36	$ 105.04	$ 96.05	$ 91.01	$ 88.15
Rubber and leather	$ 239.64	$ 196.11	$ 161.40	$ 145.70	$ 133.23	$ 126.24	$ 122.27
Secondary mill residue	$ 172.78	$ 141.39	$ 116.36	$ 105.04	$ 96.05	$ 91.01	$ 88.15
Softwood, natural, residue	$ 167.42	$ 137.00	$ 112.75	$ 101.78	$ 93.07	$ 88.18	$ 85.41
Softwood, planted, residue	$ 167.42	$ 137.00	$ 112.75	$ 101.78	$ 93.07	$ 88.18	$ 85.41
Textiles	$ 157.81	$ 129.14	$ 106.29	$ 95.95	$ 87.74	$ 83.13	$ 80.52
Tree nut residues	$ 172.00	$ 140.75	$ 115.84	$ 104.57	$ 95.62	$ 90.60	$ 87.75
Wheat straw	$ 176.00	$ 144.03	$ 118.53	$ 107.01	$ 97.85	$ 92.71	$ 89.80
Yard trimmings	$ 154.08	$ 126.09	$ 103.77	$ 93.67	$ 85.66	$ 81.16	$ 78.61

Hydrogen Production

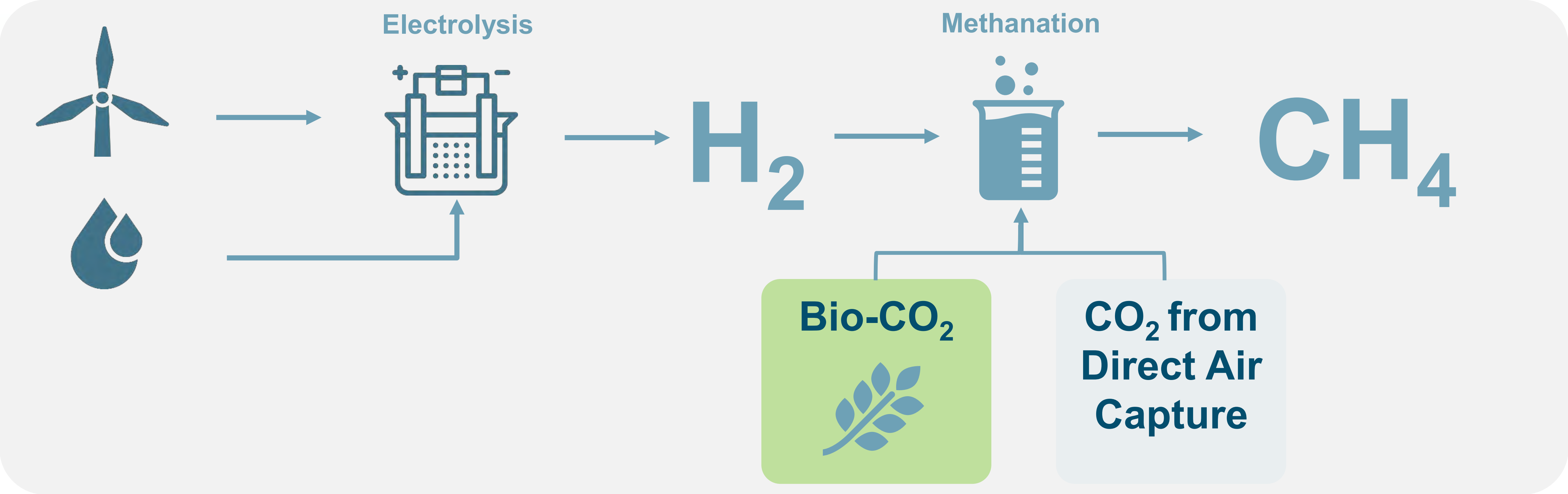
"Green" Hydrogen



"Blue" Hydrogen

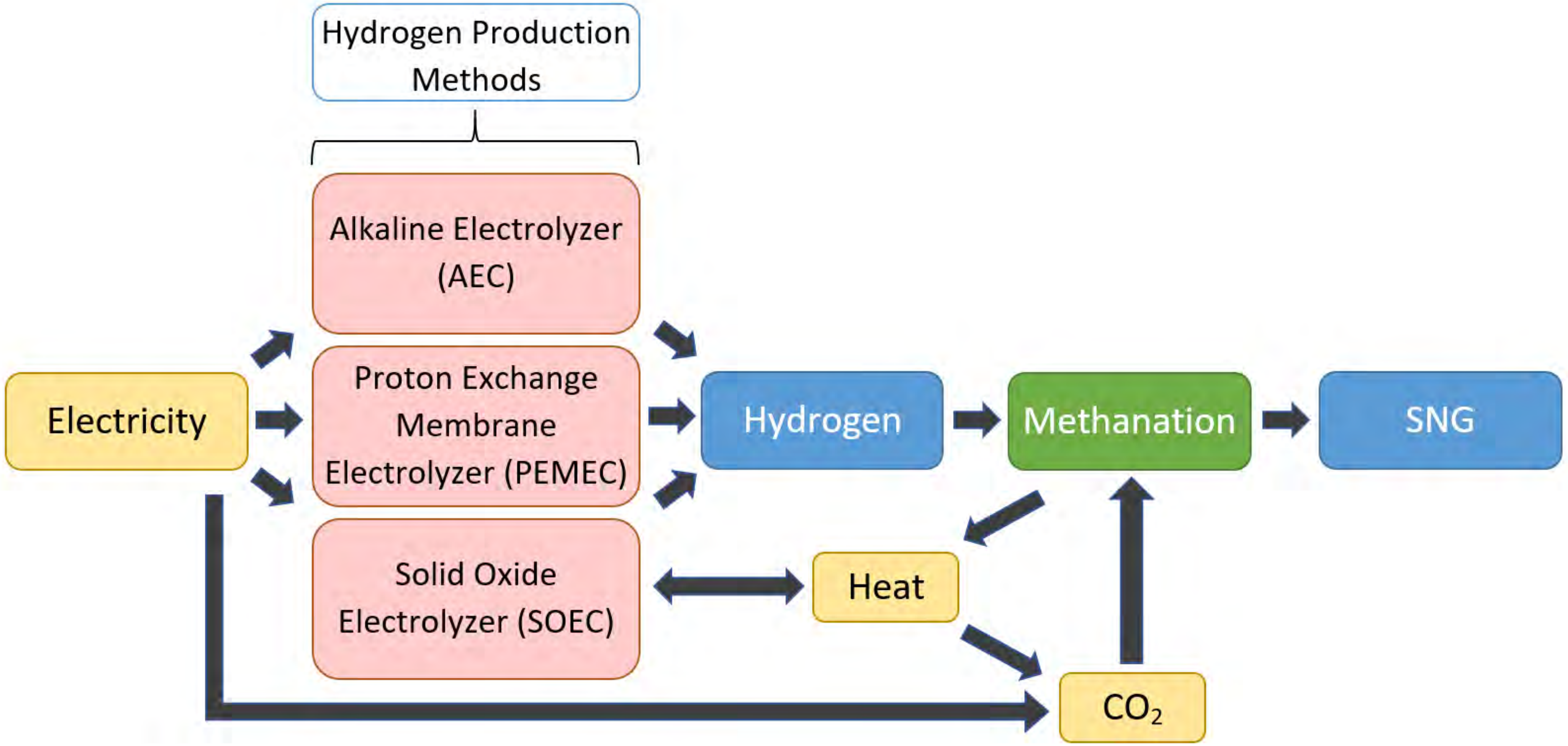


Synthetic Natural Gas (SNG) Production



- SNG production requires a combination of climate neutral hydrogen and climate neutral CO2.
- E3 considers two sources of climate neutral CO2: 1) less costly bio-CO2 from biofuels production, 2) more costly CO2 from direct air capture.

SNG Production Process

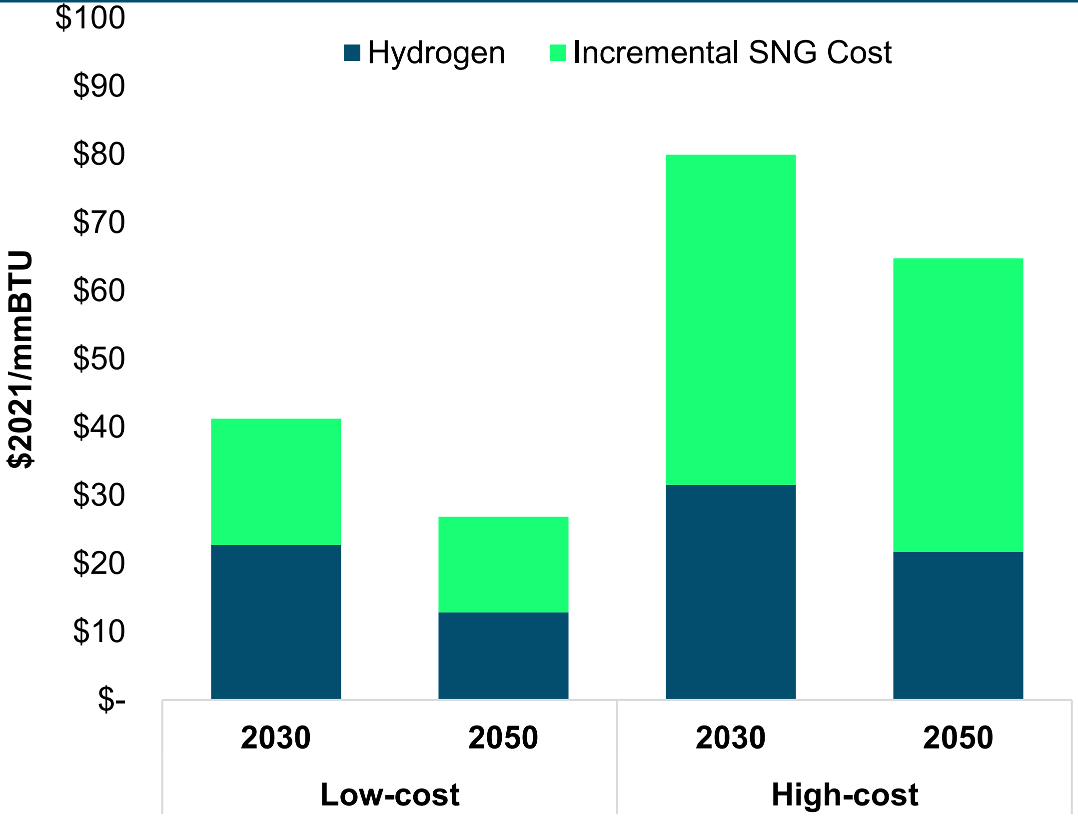


H2 and SNG Cost Assumptions

	Hydrogen (H2)		Synthetic Methane (SNG)	
Feedstock Elec	**Low**	**High**	**Low**	**High**
Cost Trajectory (main component is electrolyzer learning rate)	Optimistic - 25% electrochemcial - 14% non-electrochemical	Conservative - 10% electrochemcial - 14% non-electrochemical	Optimistic - 25% electrochemcial - 14% non-electrochemical	Conservative - 10% electrochemcial - 14% non-electrochemical
Electricity Feedstock	Input electricity price uses cost of new solar in PJM-E (cheapest available option)	Input electricity price uses cost of new solar in PJM-E (cheapest available option)	Input electricity price uses cost of new wind in PJM-E (cheapest available option)	Input electricity price uses cost of new wind in PJM-E (cheapest available option)
Infrastructure Requirement	None	None	None	None
Production Pathway	Alkaline Electrolysis (AEC)	Alkaline Electrolysis (AEC)	Biofuel Synthesis	Direct Air Capture (DAC)

Summary of Hydrogen and SNG Costs

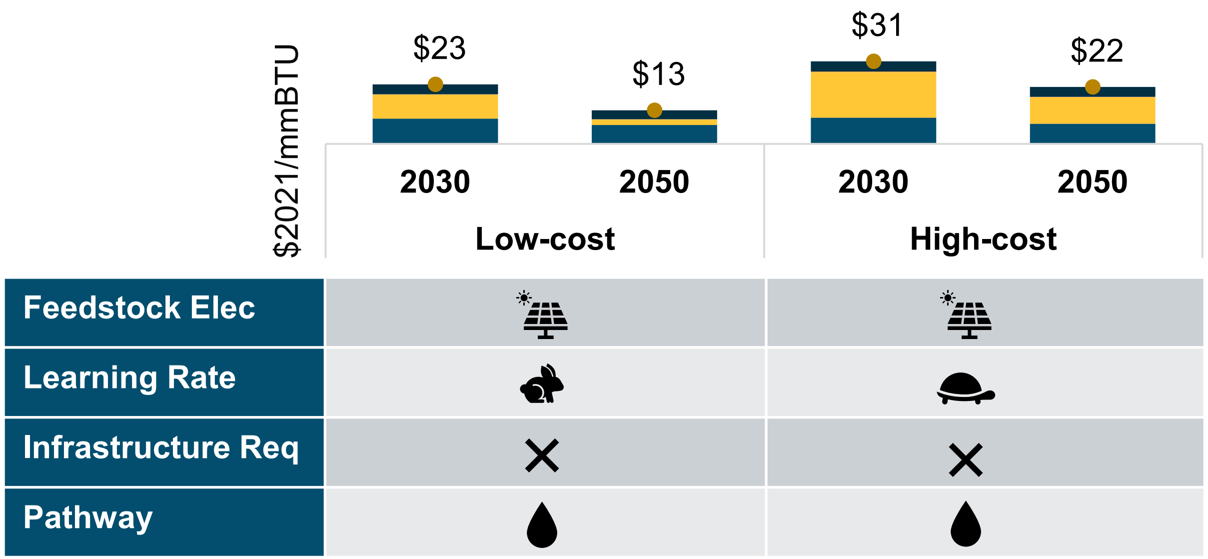
Hydrogen and Incremental SNG cost, low- and high-cost scenarios



- **Hydrogen is produced through electrolysis with off-grid solar**
- **SNG is produced with hydrogen and climate neutral CO2 through methanation**
  - SNG is tied to H2 costs
  - Low-cost scenario assumes SNG can be produced through biofuel synthesis (cheaper)
  - High-cost assumes DAC, which substantially increases associated capital costs (more expensive)
  - Additional uncertainties due primarily to electrolyzer learning rates (14% conservative, 25% optimistic)
- **We can work with MDE to evaluate the land-use implication of the off-grid renewable resources for the renewable fuel production**
- **E3 will develop biofuel costs using the Biofuel Optimization Model pending draft scenario results for fuel demand**

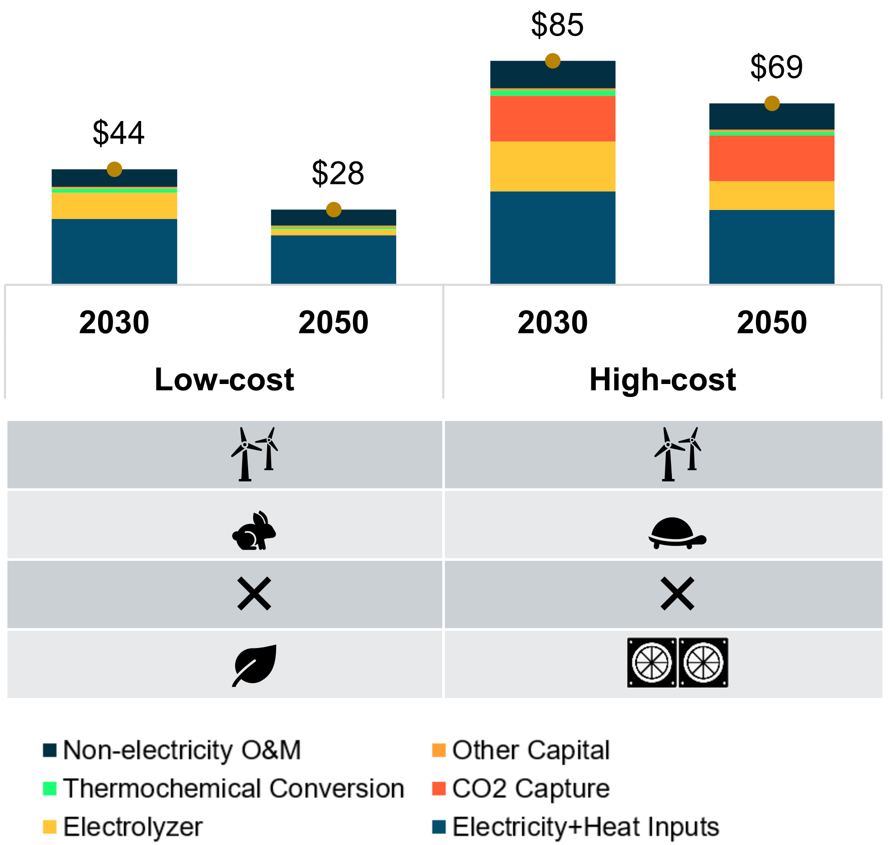
Cost breakdown

+ Hydrogen is cheaper under low- and high-cost scenarios



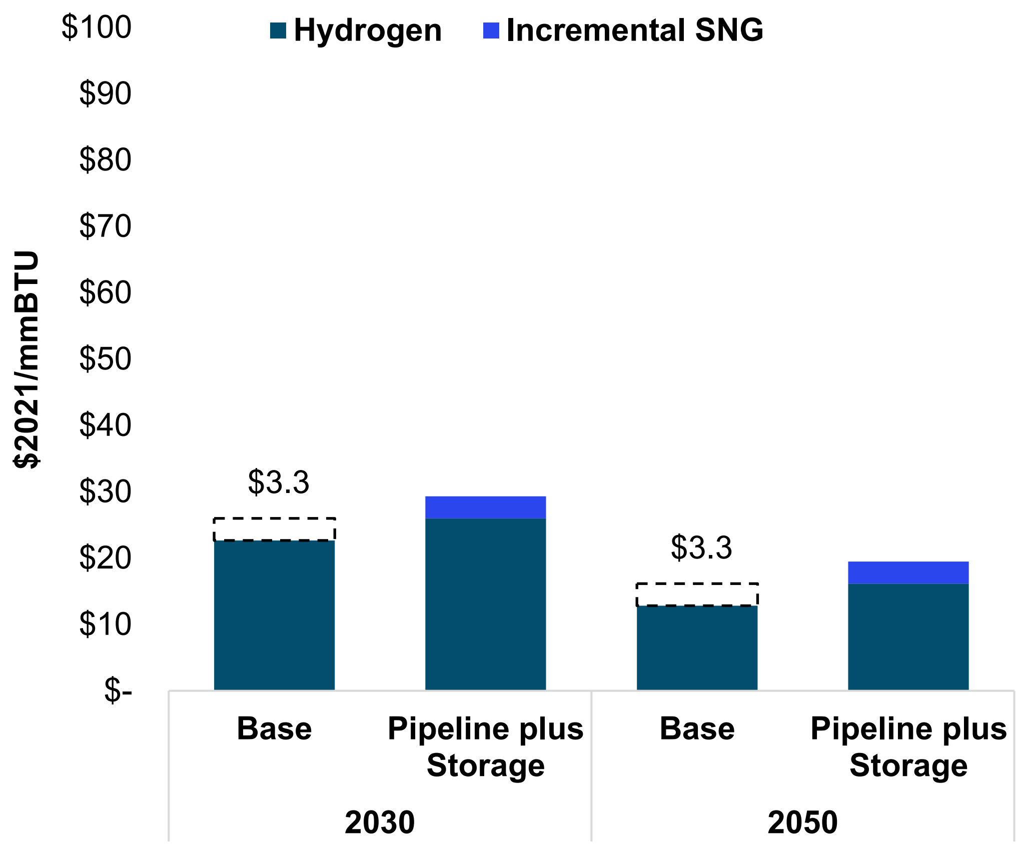
We assume H2 blends below 7% by energy such that no new storage or pipeline infrastructure is needed

+ SNG is more expensive with higher uncertainty

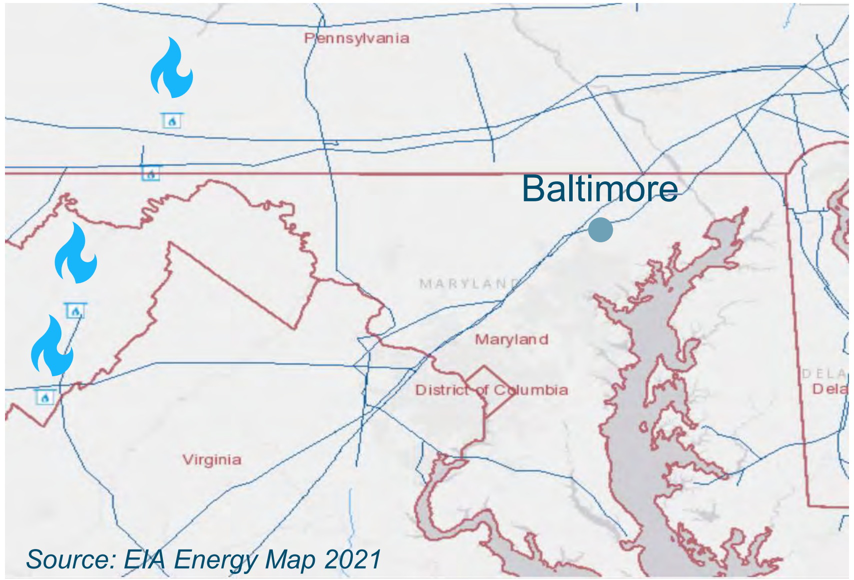


Hypothetical H2 Infrastructure

Incremental Cost of H2 Infrastructure, 2030 vs 2050



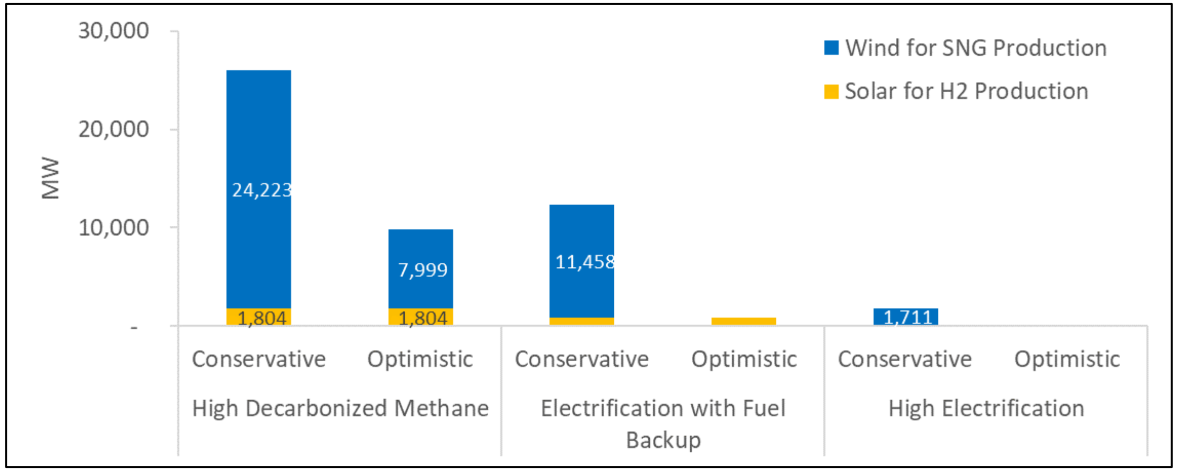
+ **Infrastructure requirements adds ~$3.3/mmBTU through 2050 to base H2 costs**



+ **Dedicated infrastructure assumes:**
  - 300 miles of new pipeline
  - Construction of underground storage

Off-grid Renewable Capacity Build for H2 and SNG Production

Renewable Capacity for H2 and SNG Production in 2045



- **This study assumes that off-grid solar will be built to supply electricity for H2 production and onshore wind for SNG production.**
- **Wind capacity totals 8-24 GW in the High Decarbonized Gas scenario by 2045 to support the large SNG demand in buildings.**
- **Energetically, it is more efficient to directly electrify end-uses than to use H2/SNG produced by renewable electricity.**
  - Heat pumps are more efficient than furnaces/boilers in supplying heat
  - H2 production has an efficiency loss of 20-30%, though can serve as an important source of storage

RESHAPE Input Assumptions

Building shell upgrades

- **Efficient building shells are assumed to lead to a 29% reduction in residential heating service demand, 10% reduction in residential cooling service demand, 34% reduction in commercial heating service demand, and 13% reduction in commercial cooling service demand**
- **A building shell upgrade consists of wall insulation, roof insulation, glazing, air-tightness, and heat recovery**

Shell Component	Upgrade Description	Low Cost ($/sq ft)*	High Cost ($/sq ft)*
Wall Insulation	Assembly R-15.6	$6.90	$15.55
Roof Insulation	Assembly R-30.0	$3.13	$5.25
Glazing	Assembly U-0.42	$1.77	$2.11
Air-Tightness	0.0448 cfm/sq ft facade	$3.75	$7.44
Heat Recovery	50% effectiveness	$0.44	$2.00

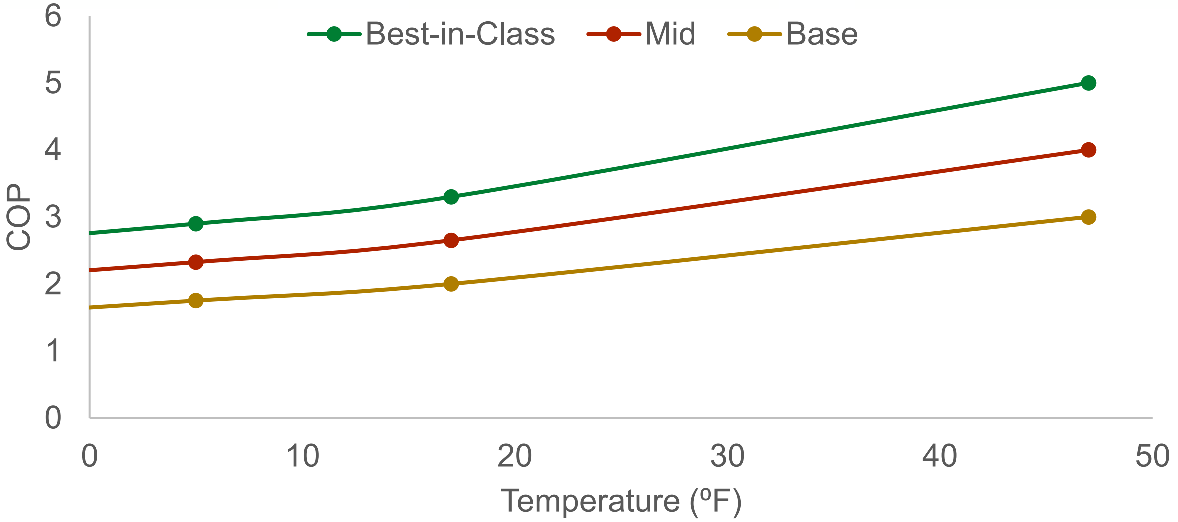
Source: Building Sector Report, A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, Massachusetts Executive Office of Energy & Environmental Affairs

Sizing criteria for ASHPs

- **ASHP with resistance backup is sized to serve the 99% peak demand, with the ASHP sized to serve the 97% peak demand for residential and the 95% peak demand for commercial**
- **ASHPs with Gas Backup are sized to serve the 80% peak demand for residential and the 88% peak demand for commercial**
- **We base the size criteria on system type assumptions and differentiate between different building types:**
  - ASHPs with resistance backup are assumed to be high-efficiency heat pumps sized to operate at full capacity down to **20ºF**
  - ASHPs with gas backup are assumed to be medium-efficiency heat pumps sized to operate at full capacity down to **30ºF**

Heat pump configuration sensitivity

RESHAPE COP Curves



Configuration	Current Installation Practice	Improved System Configuration
COP Curve	Mid	Best-in-Class
TMY Heating COP		
Residential	3.2	4.0
Commercial	2.5	3.6
Heating Sizing Percentile		
Residential	97% (~24ºF)	99% (~18ºF)
Commercial	95% (~27ºF)	99% (~18ºF)
Cooling Sizing Percentile		
Residential	99% (~89ºF)	99% (~89ºF)
Commercial	99% (~89ºF)	99% (~89ºF)

+ **E3 used manufacturer reported data on the performance of ccASHPs provided by NEEP in its Cold Climate Product Specification product listing to characterize COPs as a function of outdoor air temperature.**
+ **Three representative ccASHP systems are considered:**
  - **Best-in-Class**: consistent with the best performing systems available today COP of 2.3 @-17F
  - **Mid**: high efficiency systems COP of 1.8 @-17F
  - **Base**: systems that only just meet the NEEP requirement of a COP of 1.75 @5F, 1.3 @-17F

Average COPs and efficiency levels of appliances

Efficiency levels of ccASHPs

	Residential	Commercial
Average heating COP of ASHP with elec. resist. backup	3.17	2.48
Average cooling COP of ASHP with elec. resist. backup	4.49	4.83
Average heating COP of ASHP with fuel backup	4.57	6.19
Average cooling COP of ASHP with fuel backup	4.49	4.83
Supp Heat % of Total SD for Hybrid ASHP (with fuel backup)	25.5%	47.9%

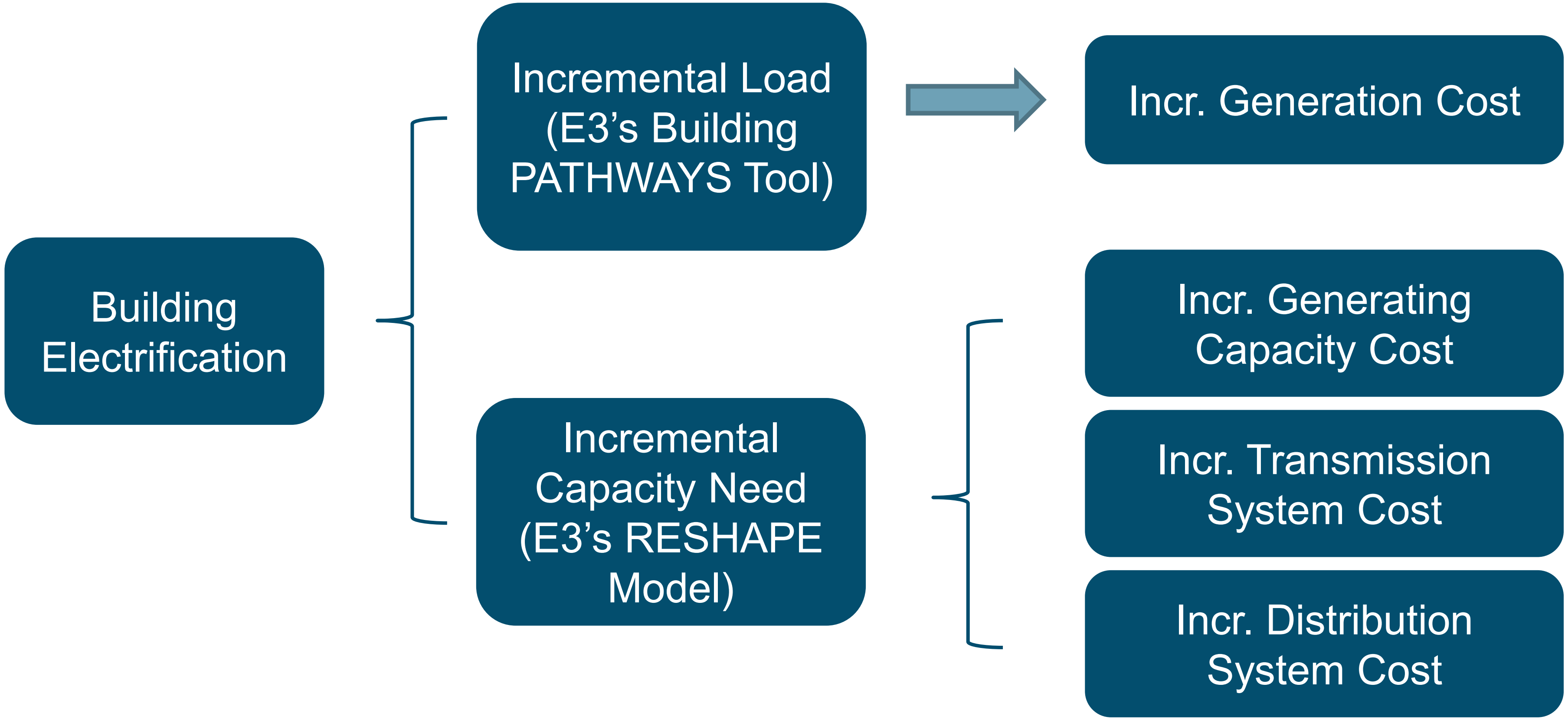
Other efficiency levels

	Residential	Commercial
Average cooling COP of Reference AC	3.20	3.22
Average cooling COP of High Efficiency AC	3.40	3.72
Average heating COP of Reference Gas Furnace	82%	80%
Average heating COP of High Efficiency Gas Furnace	96%	98%
Average heating COP of Reference Electric Resistance	98%	99%
Average heating COP of Reference Fuel Oil	83%	80%
Average heating COP of Reference Heat Pump	2.43	1.89
Average heating COP of Reference Gas Water Heater	60%	80%
Average cooling COP of Heat Pump Water Heater	250%	300%

Revenue Requirement Model Assumptions

Modeling Approach –Electric System Cost

+ **E3 will model the incremental electric system cost relative to the total electric system costs under the 2030 GGRA plan through the following framework.**



+ **Each cost component will be allocated to residential and commercial sectors based on its contribution to load and the coincident peak**

Electricity System – Generation + Storage

- **Incremental electricity demand will be met by renewable generation in the RGGI PJM states (a combination of 63% solar and 28% onshore wind) and imports from the rest of PJM (9%)**
  - The share of imports from the non-RGGI PJM states are consistent with the 2030 GGRA Plan
  - The share of solar and onshore wind serving the rest of the incremental load is determined based on E3's capacity expansion modeling of PJM East under an ambitious RGGI decarbonization scenario.
  - The cost of generation will be the weighted average LCOE of these resources available in PJM East, based on NREL ATB 2020 mid cost trajectories.

Resource	2021 Cost	Cost Escalation (Real %/yr)
Generation ($/MWh)	$49	-0.56%
Storage ($/kW-yr)	$144	-2.12%

Resource	Marginal ELCC %
Solar + Storage	33%
Wind	13%

- **Energy storage capacity build will be 4.5% of peak load in 2040 with the build beginning in 2030, consistent with E3 modeling of PJM East under an ambitious decarbonization trajectory.**
- **Generation capacity needs will be assessed based on the incremental coincident peak load net of the effective load carrying capability (ELCC) of solar + storage, wind and imports to meet the increase in annual load from electrification.**

Electric System - Capacity

+ **Transmission:** Estimated based on a 2019 Brattle Report as $200/kW and levelized using a revenue requirement multiplier of 1.61 and an assumed cost of capital of 7.74%.
+ **Distribution:** Distribution cost estimated based on E3's review of publicly available data on distribution investment and deferral values.
+ **Generation**:
  - Near term value determined by the averaged results of the PJM capacity auction for PEPCO and BGE LDA's ($111/MW-day)
  - Long term values determined as the cost of a greenfield CT.

Component	Cost (2021$/kW-yr)		Cost Escalation (Real %/yr)	Source
	2021-2023	2024-2045		
Transmission Capacity	$28		2.35%	2019 Brattle Report
Distribution Capacity	$40		2.35%	E3 Review of Public Data
Generation Capacity	$41	$90	0.10%	PJM Capacity Auction, Greenfield CT Cost

Modeling Approach – Gas System Cost

- **E3 models both commodity costs and delivery costs for the gas system**
- **Commodity (cost of gas):**
  - $/MMBtu commodity rate will depend on the blend of zero-carbon fuels into the pipeline and the cost to produce biogas, hydrogen and synthetic natural gas
- **Delivery (cost of infrastructure):**
  - Delivery or fixed cost of the gas system will depend on growth or retirement of the system
  - In the case where there is reduced gas throughput due to building electrification and the gas system is not paired down at the same pace, the average $/MMBtu delivery rate must increase to meet system revenue requirement

Gas System

- **Current Maryland gas system delivery costs** were determined based on **EIA reports** of statewide rates and natural gas sales as well as current allocation of delivery costs to customer classes.
- **Delivery cost** consists of **rate base, O&M, depreciation** and **taxes**
- 10-K filings for Baltimore Gas and Electric and Washington Gas Light Company were used to estimate for each delivery cost component the current breakdown and statewide historical annual growth rate.

2019 Total Delivery Cost: $1,023 MM

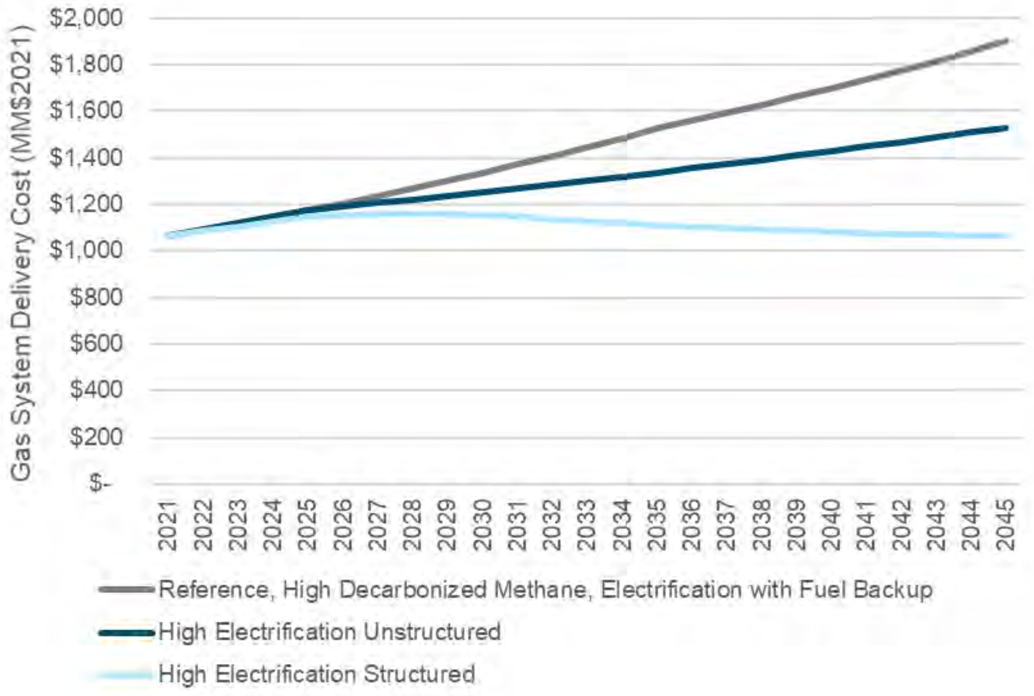
Class	Allocation
Residential	61%
Commercial	37%
Other	2%

Revenue Requirement Breakdown and Growth

	Share of Current Delivery Cost	CAGR (2016-2020) Nominal %
Rate Base	43%	6.25%
O&M	30%	2.93%
Depreciation	18%	6.58%
Taxes	9%	4.06%

Gas System – Delivery Cost Scenarios

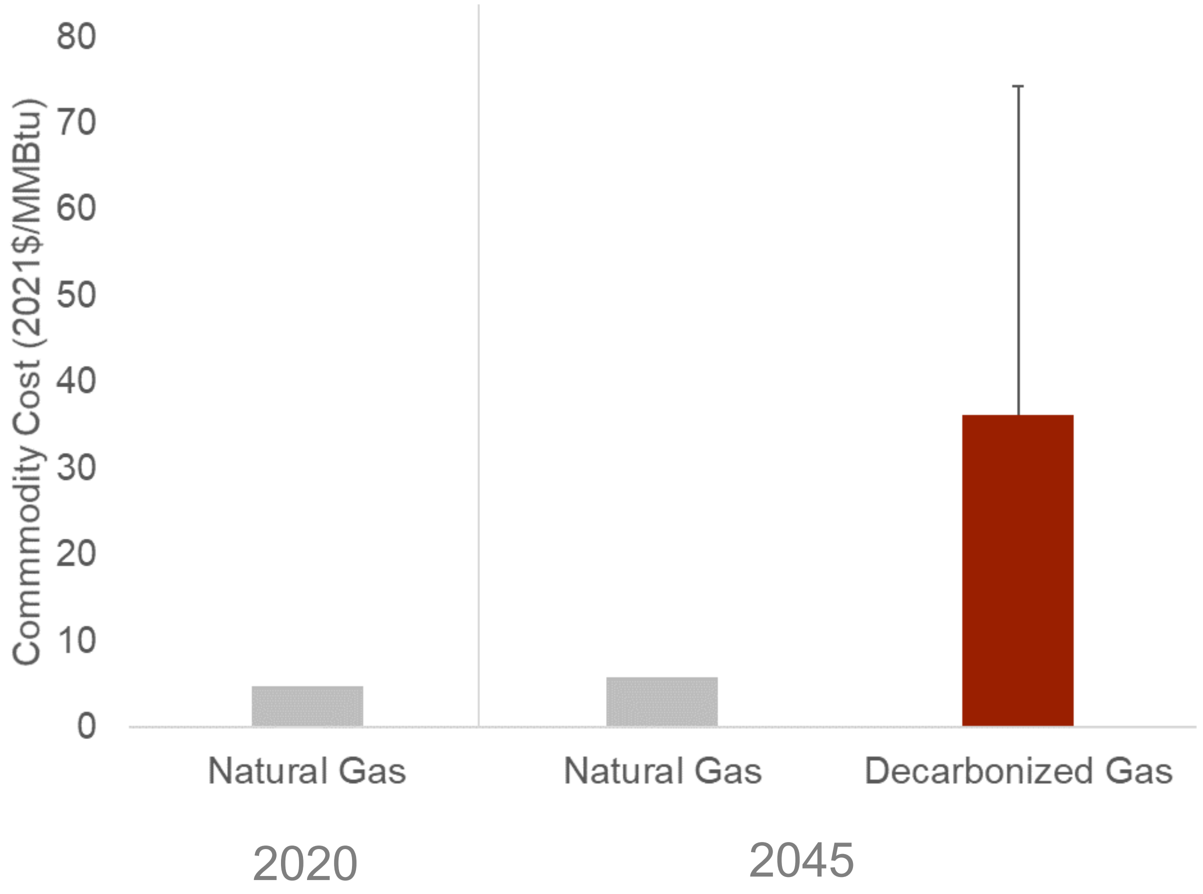
- In the **Reference, High Decarbonized Methane,** and **Electrification with Fuel Backup** scenarios, the historical growth rates for each component of the delivery cost are assumed to continue into the future except for the rate base growth rate, which is assumed to decline to 3.12% (nominal) starting in 2035 consistent with the STRIDE program.
- In the **Unstructured High Electrification** scenario, the historical growth rates of all components of the delivery cost are assumed to decline by 50% starting in 2025 due to reduced throughput.
- In the **Structured High Electrification** scenario:
  - The rate base, depreciation, and taxes growth rates declines to 50% of the historical rate from 2025 to 2030. The rate base, depreciation, and taxes costs remain flat after 2030.
  - Distribution system maintenance is assumed to be 33% of the O&M cost. The growth rate for distribution cost is assumed to decline by 50% of the historical rate from 2025 to 2030 after which the distribution system maintenance cost will remain flat.
  - Administration costs are assumed to be 67% of the O&M cost. Administration costs are assumed to decline by 0.6% per 1% decline in customer base as customers electrify.



Detail Rate Impact

Commodity costs of gas grow as a result of an increased zero-carbon fuels blend

Average gas commodity costs (2021$/MMBtu)

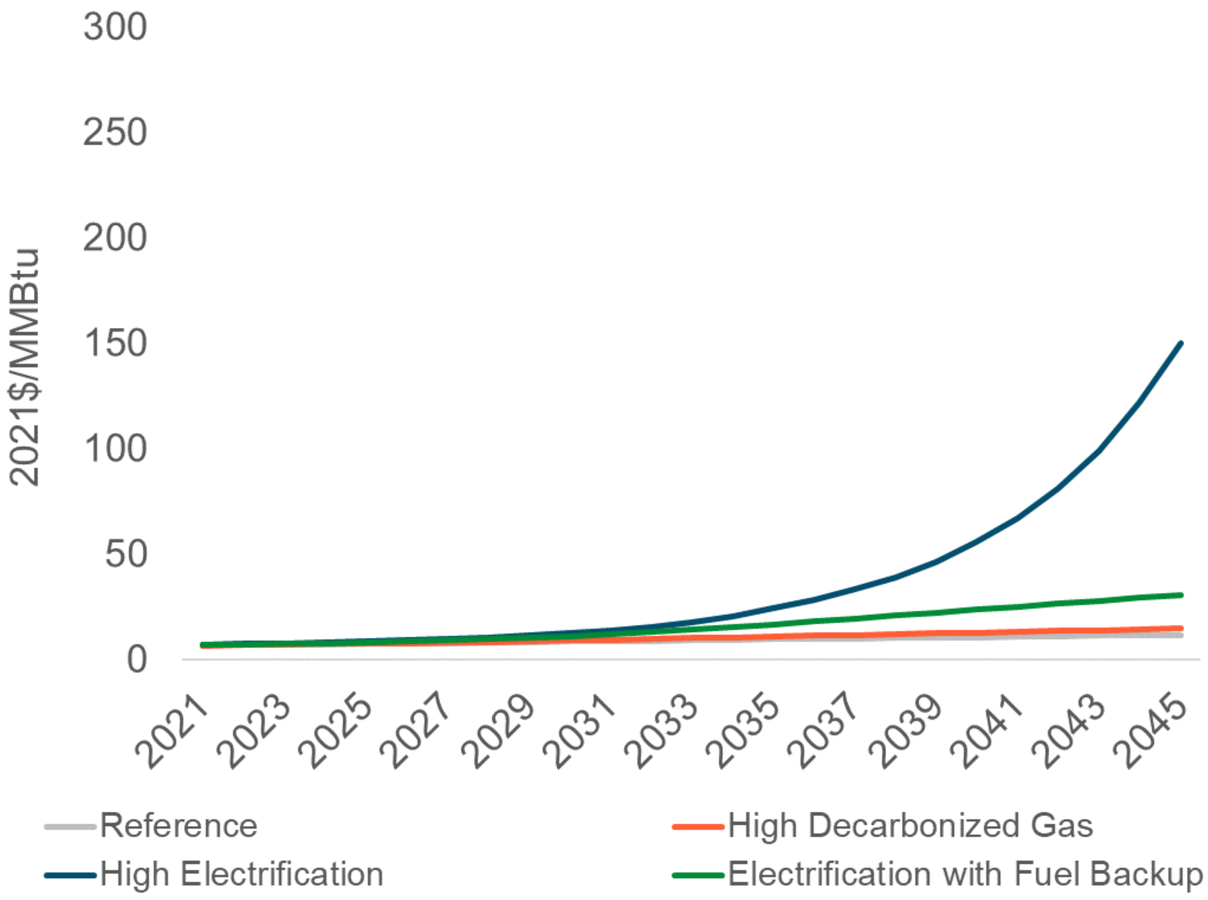


- **Commodity costs of gas increase steeply as a result of blending of zero-carbon fuels**
- **Uncertainty range shows difference between 'optimistic' and 'conservative' RNG Supply assumptions, resulting in a significant differentiation.**
- **All scenarios have the same range of commodity costs as the SNG is the marginal resource in all scenarios.**

Sources & assumptions: cost assumptions for RNG and hydrogen based on E3's biofuels module and Hydrogen Production module (see Appendix). Costs in the reference case are based on natural gas prices from EIA AEO 2020.

Delivery costs of gas increase dramatically as more and more households electrify

Residential gas delivery costs (2021$/MMBtu)



- **High Electrification scenario experiences a rapid increase in per unit delivery costs after 2025 due to the reduced gas throughput, regardless of the fact that total delivery cost is lower than in other scenarios**
  - High Electrification scenario assumes earning on rate base, depreciation, and O&M growth rates halved after 2025 leading to a 25% decline in total delivery costs by 2045.
  - As gas throughput and peak gas demand declines in the High Electrification scenario, reinvestment and maintenance for the gas system are expected to scale down.
- **Reference, High Decarbonized Gas, and Electrification with Fuel Backup scenarios assume the historical earning on rate base growth rate is halved beginning 2035 assuming STRIDE is completed.**

Sources & assumptions: current Revenue Requirement (RR) is estimated using Maryland specific delivery prices per sector from EIA. Rate base increases are based on historical averages and flat capital expenditures (see Appendix). Scenarios assume a "Business as Usual" allocation of Revenue Requirement to customer groups. Cost allocations might shift as the ratio of consumption changes.

Energy+Environmental Economics

Building Stock Characterization

Draft Results

Building Stock Characterization: Original Criteria

+ Objective: Represent and model different customer segments to evaluate consumer economics

+ Considerations:

- Capital cost is a key driver of consumer economics
- Equipment type and retrofit efforts are main factors of capital costs

Residential Criteria	Variants
Building Type	Single Family, Multi-Family
Building Vintage	Retrofit New Construction
Existing AC	AC No AC
Existing Equipment – Space Heating	Electric Resistance Natural Gas Fuel Oil
Climate Zone (IECC)	IECC Zone 4A IECC Zone 5A

Commercial Criteria	Variants
Existing System/Vintage/Size	Packaged/window units for heating and cooling (~ smaller/older) Boiler + Chiller (~ larger/newer) New construction
Existing Fuel	Electric Resistance Natural Gas Fuel Oil
Existing AC	AC No AC
Climate Zone	IECC Zone 4A IECC Zone 5A

Building Stock Characterization: Adjustments to criteria

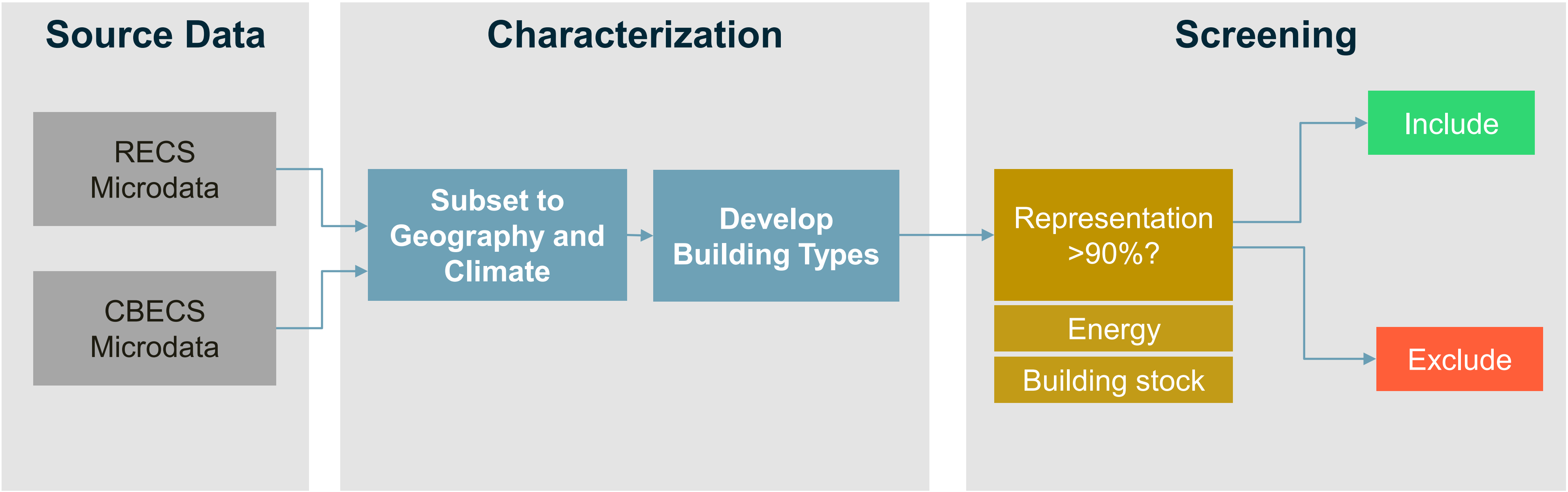
- **Eliminated Climate Zone Criteria** - Zone 5A < 1.5% of population
- **Modified vintaging** – Use RECS/CBECS for reference shell, add assumptions for new construction
- **Refined commercial equipment** – considered existing AC and space heating equipment

Residential Criteria	Variants
Building Type	Single Family, Multi-Family
Building Vintage	Retrofit New Construction
Existing AC	AC No AC
Existing Equipment – Space Heating	Electric Resistance Natural Gas Fuel Oil
~~Climate Zone (IECC)~~	~~IECC Zone 4A~~ ~~IECC Zone 5A~~

Commercial Criteria	Variants
Air Conditioning	**Central AC** **Packaged AC** **Other AC**
Space Heating	**Central SH** **District SH**
Heat Pump	**Heat Pump**
~~Climate Zone~~	~~IECC Zone 4A~~ ~~IECC Zone 5A~~

Building Stock Characterization: Approach

- Develop representative building types based on RECS and CBECS microdata
- Determine average stock share and energy consumption for each building type
- Include most representative building types



Residential Characterization: Representative Building Types

+ Ten building types selected

- represents 97% of residential households and 98% of residential energy use

Segment	Single Family		Multifamily	
Space Heating Equipment	**Has AC**	**No AC**	**Has AC**	**No AC**
Electric Resistance	19%		5%	2%
Natural Gas	24%	<1%	10%	
Fuel Oil	12%			
Heat Pump	20%		2%	
Other	4%			
Share of Res Households	**78%**	**<1%**	**17%**	**2%**

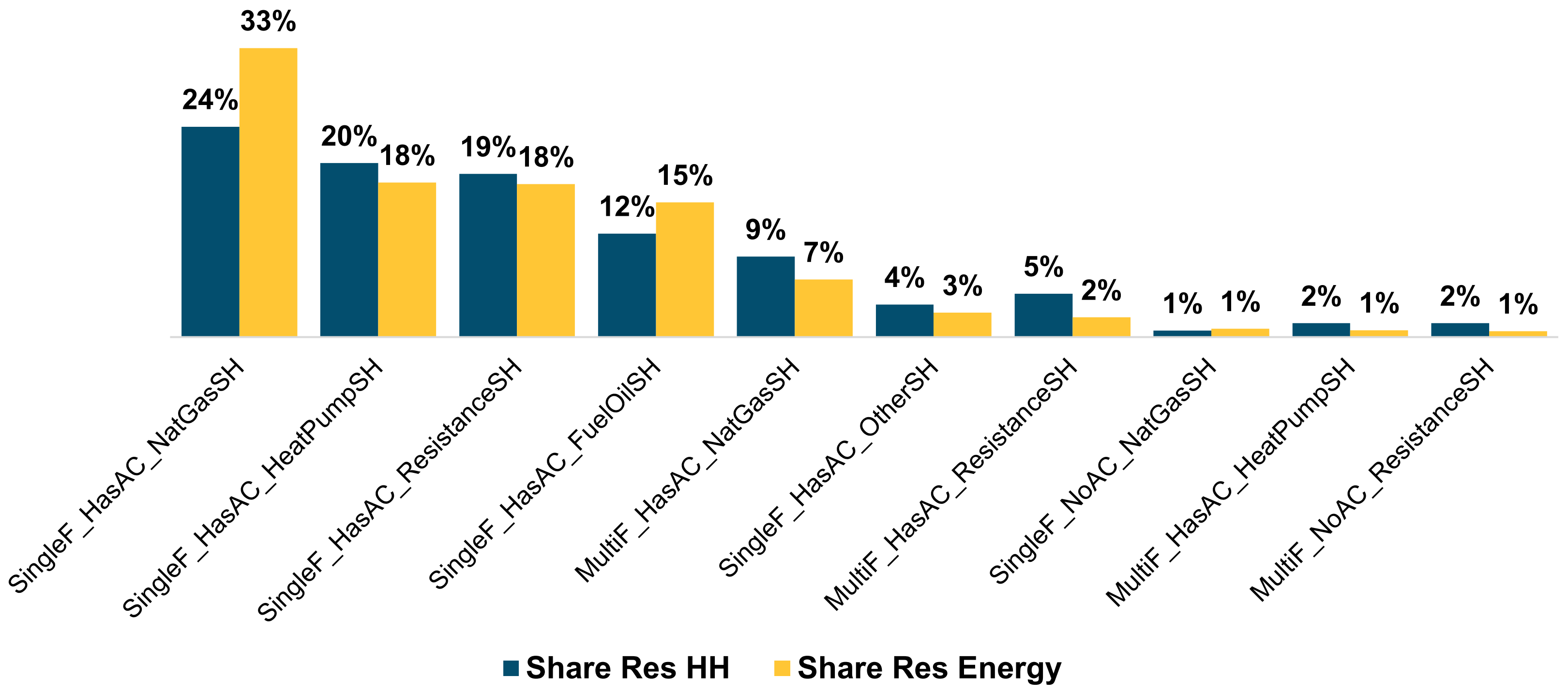
Excluded categories represent <4% of total households

= Equipment combination excluded from analysis

Residential Building Stock Characterization

+ Ten building categories represent the vast majority of residential buildings

- > 98% of residential energy use
- > 96% of residential households



Commercial Characterization: Representative Building Types

+ Five building types selected

- Represent 93% of commercial floorspace and 95% of commercial energy use

Space Heating Equipment	Central AC	Packaged AC	No AC	Heat Pump
Central Heating	16%	45%	8%	
Heat Pump				17%
District Heating	6%			
Share of Com Floorspace	**22%**	**45%**	**8%**	**17%**

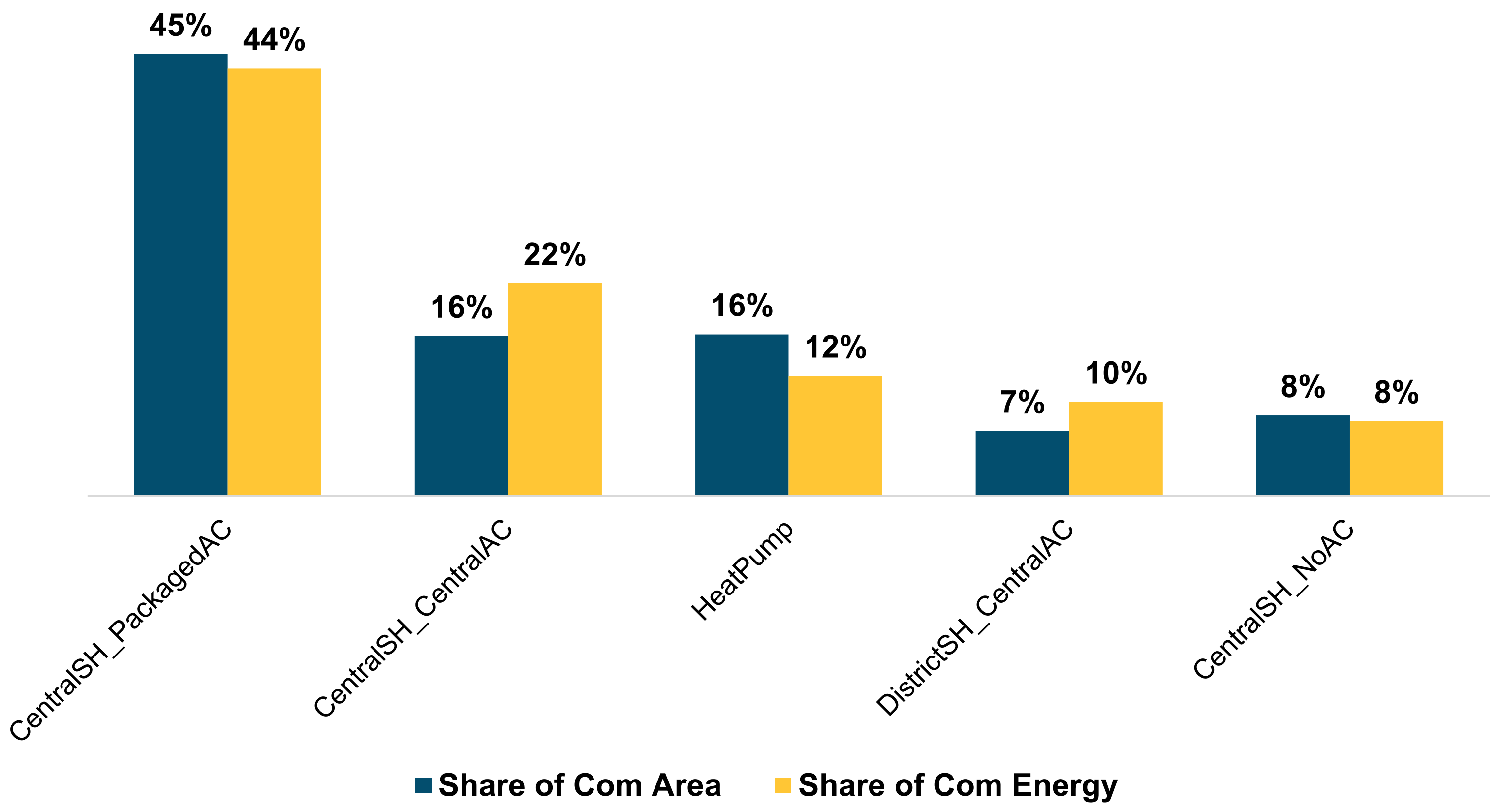
Excluded categories represent < 8% of commercial floorspace

= Equipment combination excluded from analysis

Commercial Building Stock Characterization

+ Five building categories represent the majority of commercial buildings

- > 94% of commercial energy use
- > 92% of commercial floorspace



Appendix: Residential Building Types

Building Type	Share of Area	Share of Energy
SingleF_HasAC_NatGasSH	24.15%	33.18%
SingleF_HasAC_HeatPump SH	19.96%	17.74%
SingleF_HasAC_Resistance SH	18.72%	17.55%
SingleF_HasAC_FuelOilSH	11.87%	15.46%
MultiF_HasAC_NatGasSH	9.22%	6.61%
SingleF_HasAC_OtherSH	3.73%	2.79%
MultiF_HasAC_ResistanceS H	4.97%	2.25%
SingleF_NoAC_NatGasSH	0.74%	0.96%
MultiF_HasAC_HeatPumpS H	1.57%	0.78%
MultiF_NoAC_ResistanceSH	1.58%	0.68%
Totals	**96.5%**	**98.0%**

Appendix: Commercial Building Types

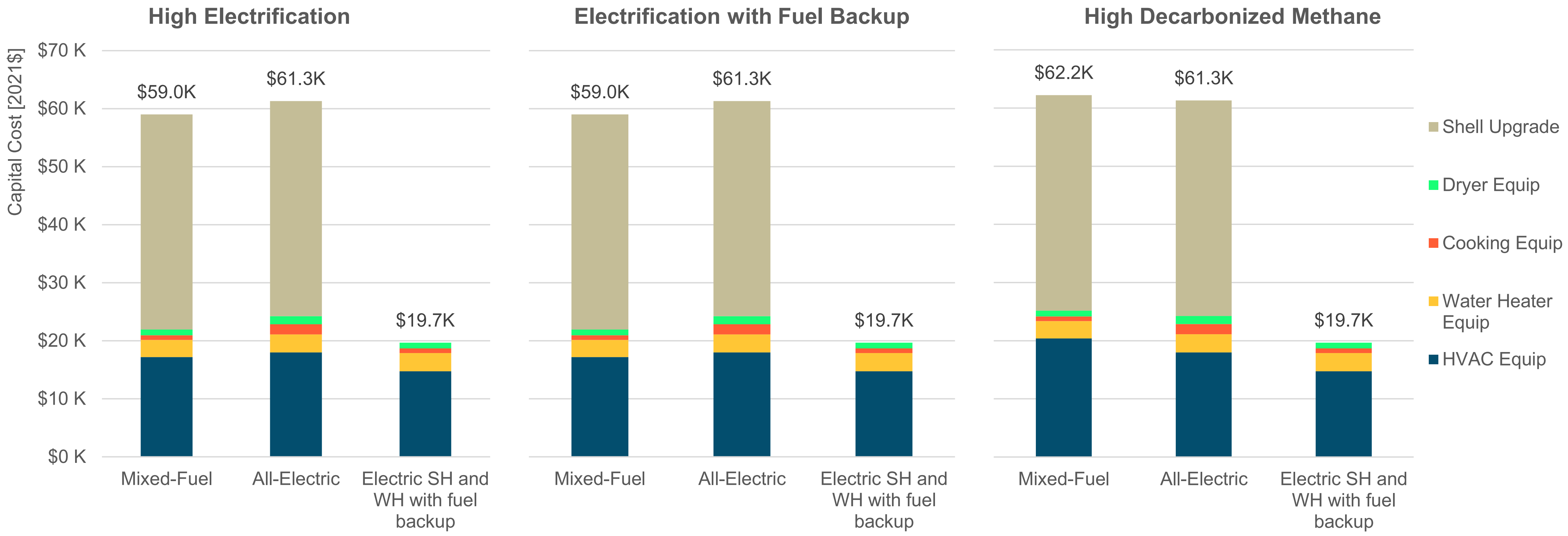
Building Type	Share of Area	Share of Energy	Median Square Feet	Median Annual kBTUs	Median Year Constructed
CentralSH_PackagedAC	44.99%	43.54%	24,000	1,689,634	1988
CentralSH_CentralAC	16.28%	21.66%	205,000	17,333,404	1985
HeatPump	16.46%	12.23%	6,400	418,621	1988
DistrictSH_CentralAC	6.62%	9.58%	282,500	30,916,029	1969
CentralSH_NoAC	8.20%	7.63%	5,900	364,809	1984
Totals	**90.7%**	**94.2%**			

Additional Consumer Cost Results

Draft Results

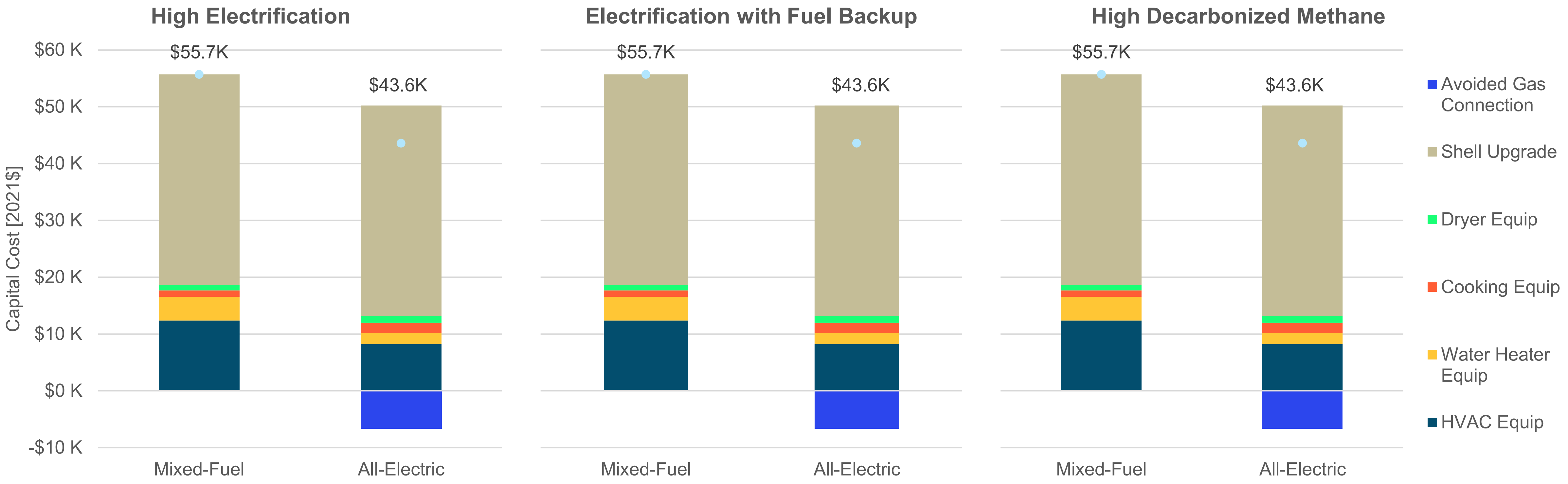
Switching to heat pumps saves costs for both retrofit and new construction residential single-family customers

+ **For single-family residential retrofit customers, installing a heat pump instead of a combined high-efficiency gas furnace + A/C system saves upfront cost**



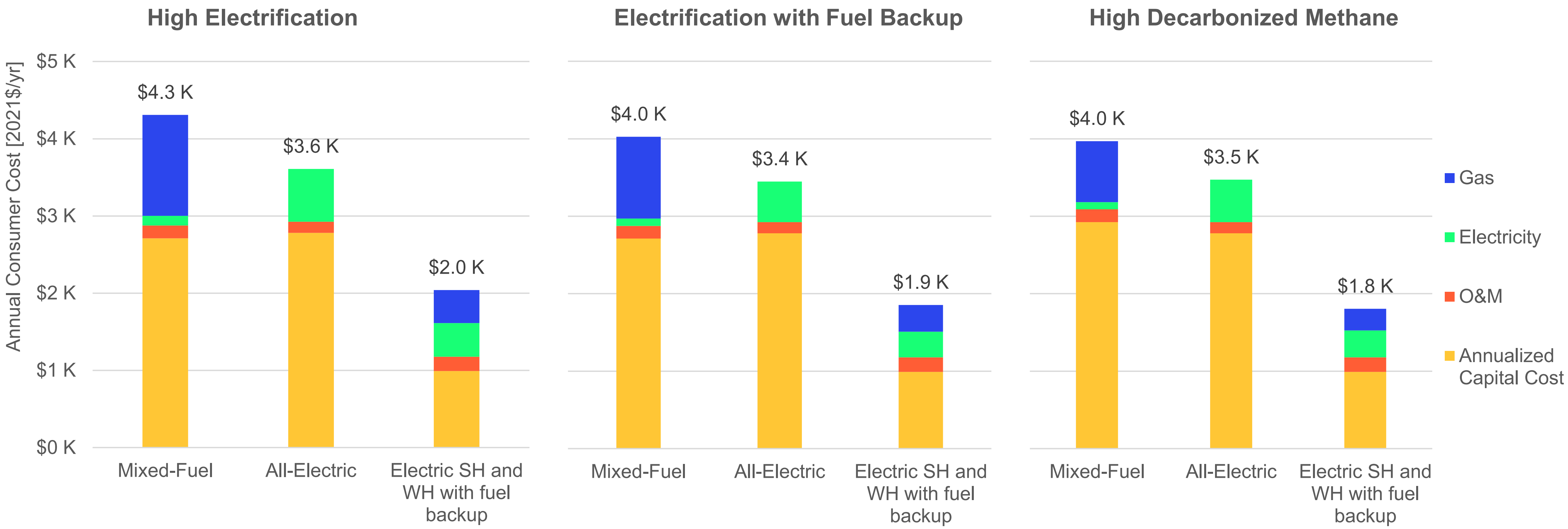
Switching to heat pumps saves costs for both retrofit and new construction residential single-family customers

+ All-electric new construction buildings are less expensive than mixed-fuel buildings



Multifamily residential retrofit consumer cost impact

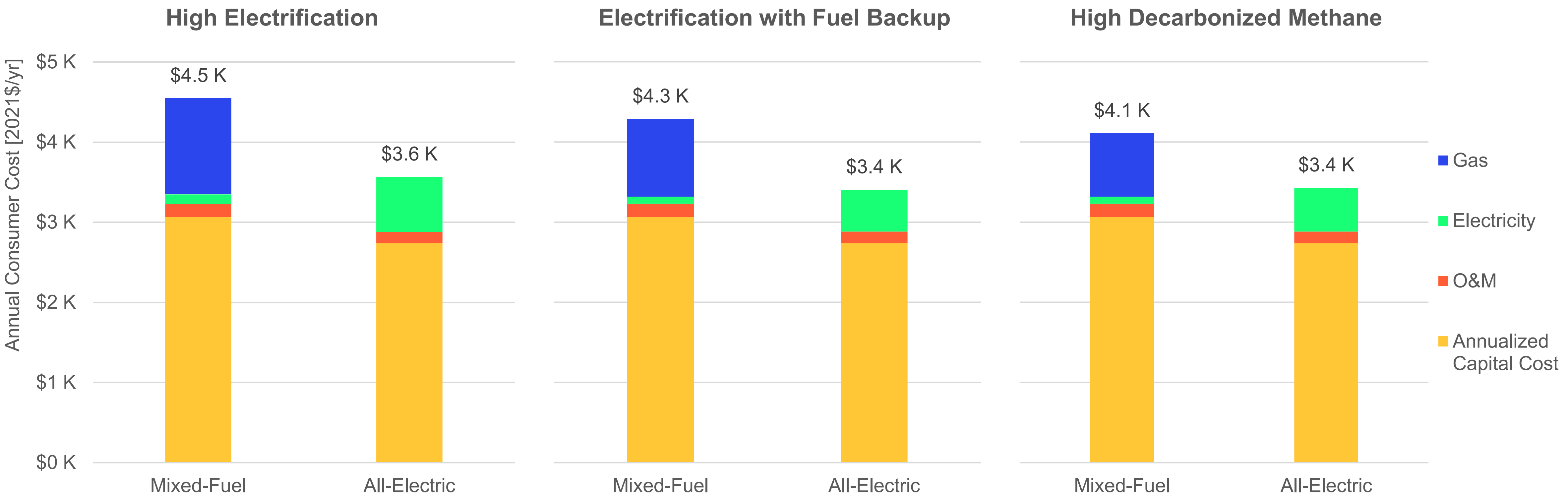
+ **"Hybrid" customers can save money by utilizing their existing fuel-based heating equipment to provide backup heating during coldest hours of a year, and by not having to upgrade building shells**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent "optimistic" rate scenario ("conservative" gas scenario has 5% higher total cost for mixed-fuel)

Multifamily residential new construction consumer cost impact

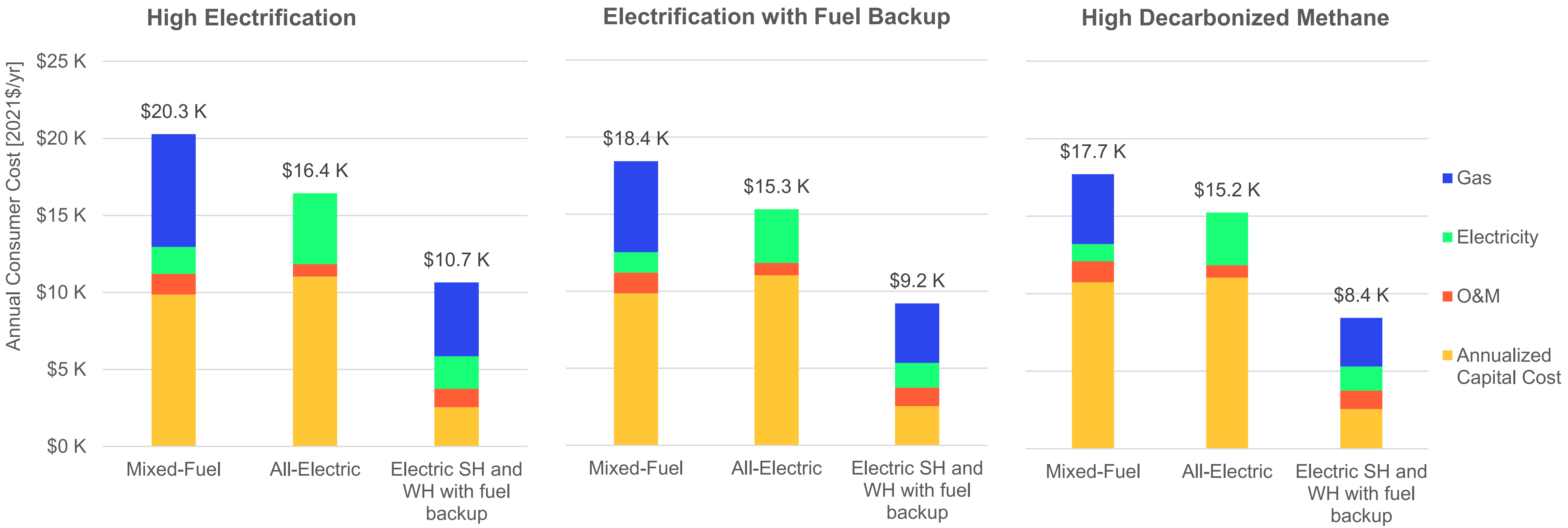
+ **All-electric new construction is cheaper than mixed-fuel new construction for multifamily residential homes across all decarbonization scenarios due to both lower capital (with avoided gas connection) and operating costs**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent "optimistic" rate scenario ("conservative" gas scenario has 4.5% higher total cost for mixed-fuel)

Small commercial retrofit consumer cost impact

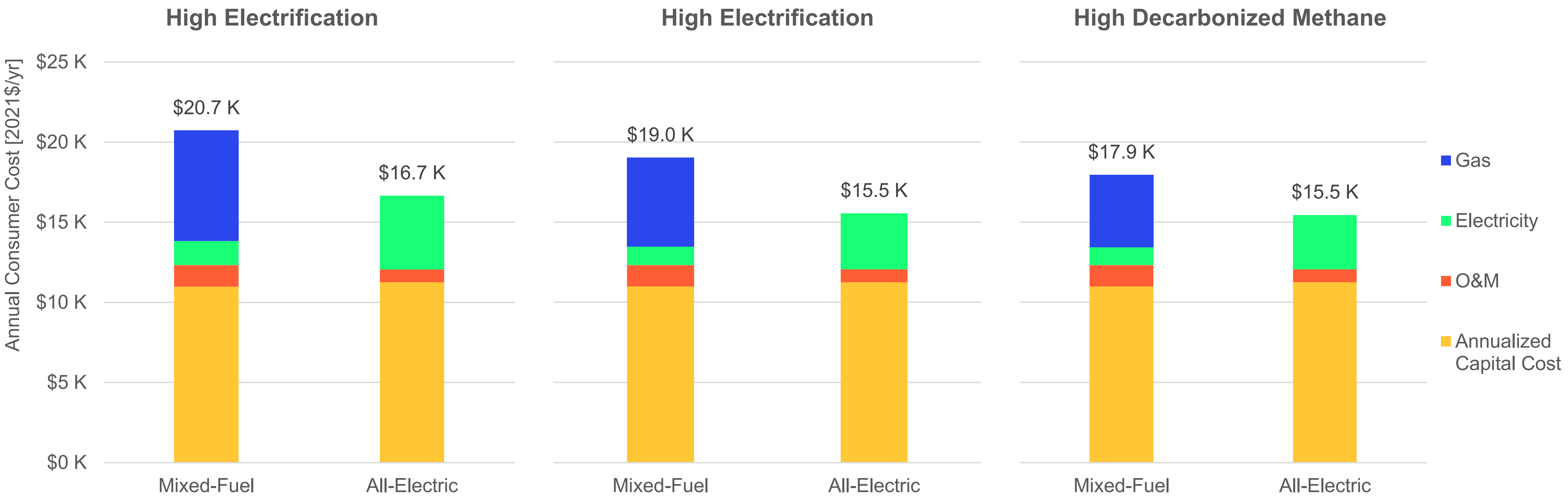
+ **"Hybrid" customers can save money by utilizing their existing fuel-based heating equipment to provide backup heating during coldest hours of a year, and by not having to upgrade building shells**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent "optimistic" rate scenario ("conservative" gas scenario has 6% higher total cost for mixed-fuel)

Small commercial new construction consumer cost impact

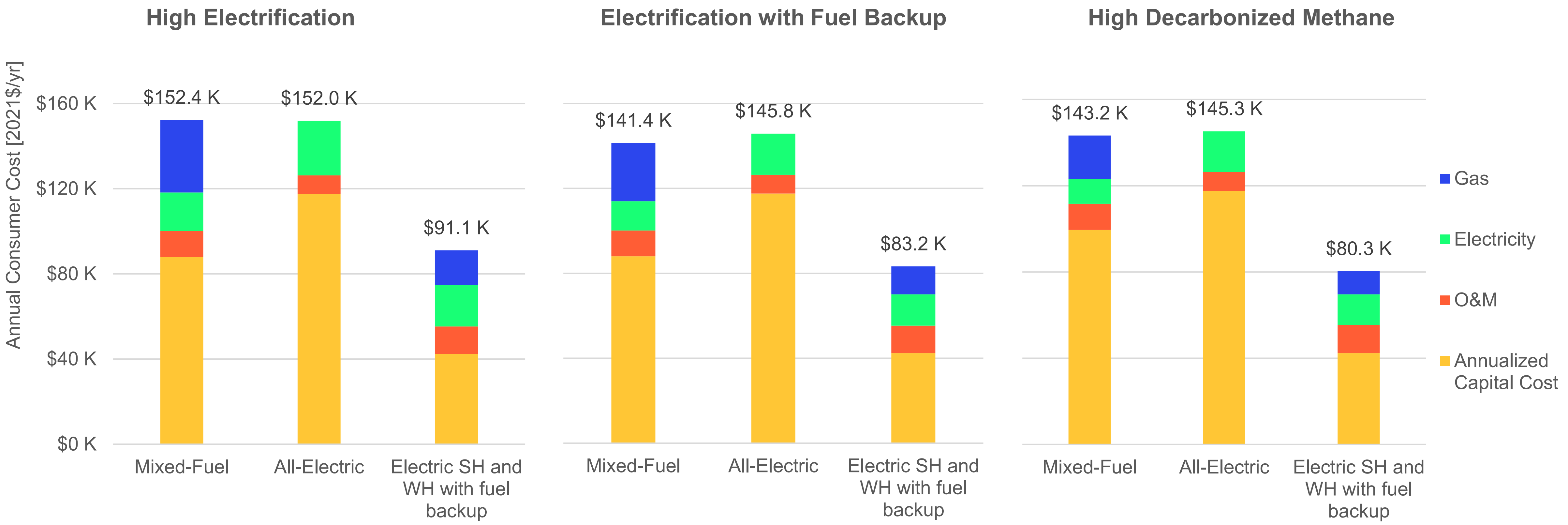
+ **All-electric new construction is cheaper than mixed-fuel new construction for small commercial buildings across all decarbonization scenarios due to both lower capital (with avoided gas connection) and operating costs**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent "optimistic" rate scenario ("conservative" gas scenario has 6% higher total cost for mixed-fuel)

Large commercial retrofit consumer cost impact

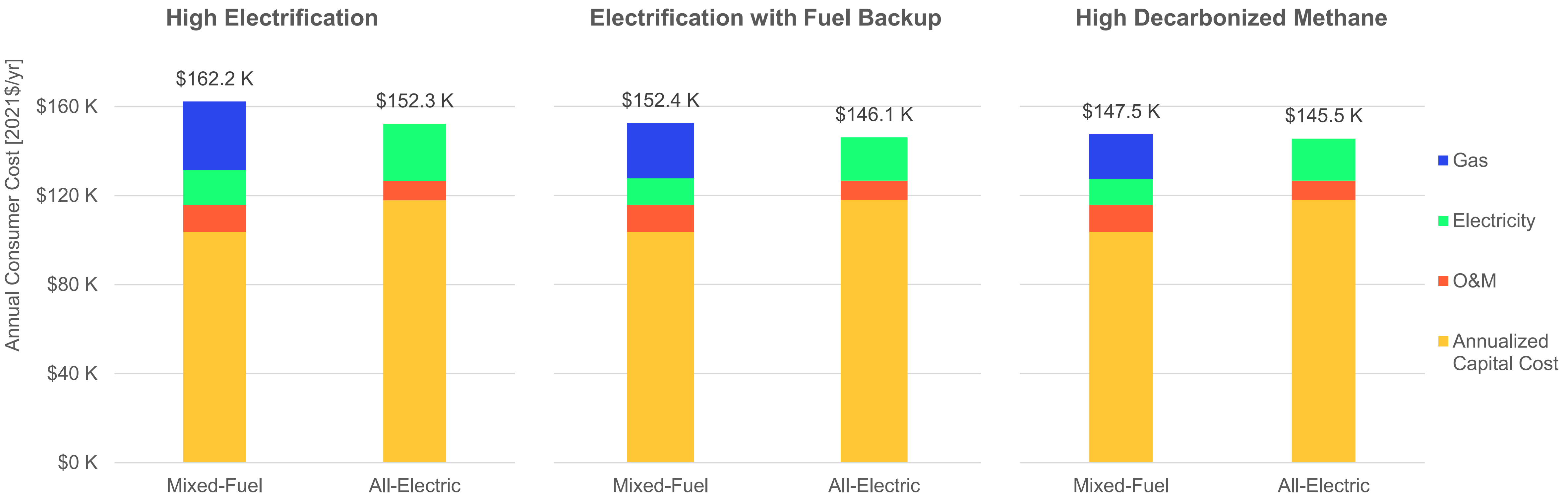
+ **"Hybrid" customers can save money by utilizing their existing fuel-based heating equipment to provide backup heating during coldest hours of a year, and by not having to upgrade building shells**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent "optimistic" rate scenario ("conservative" gas scenario has 4% higher total cost for mixed-fuel)

Large commercial new construction consumer cost impact

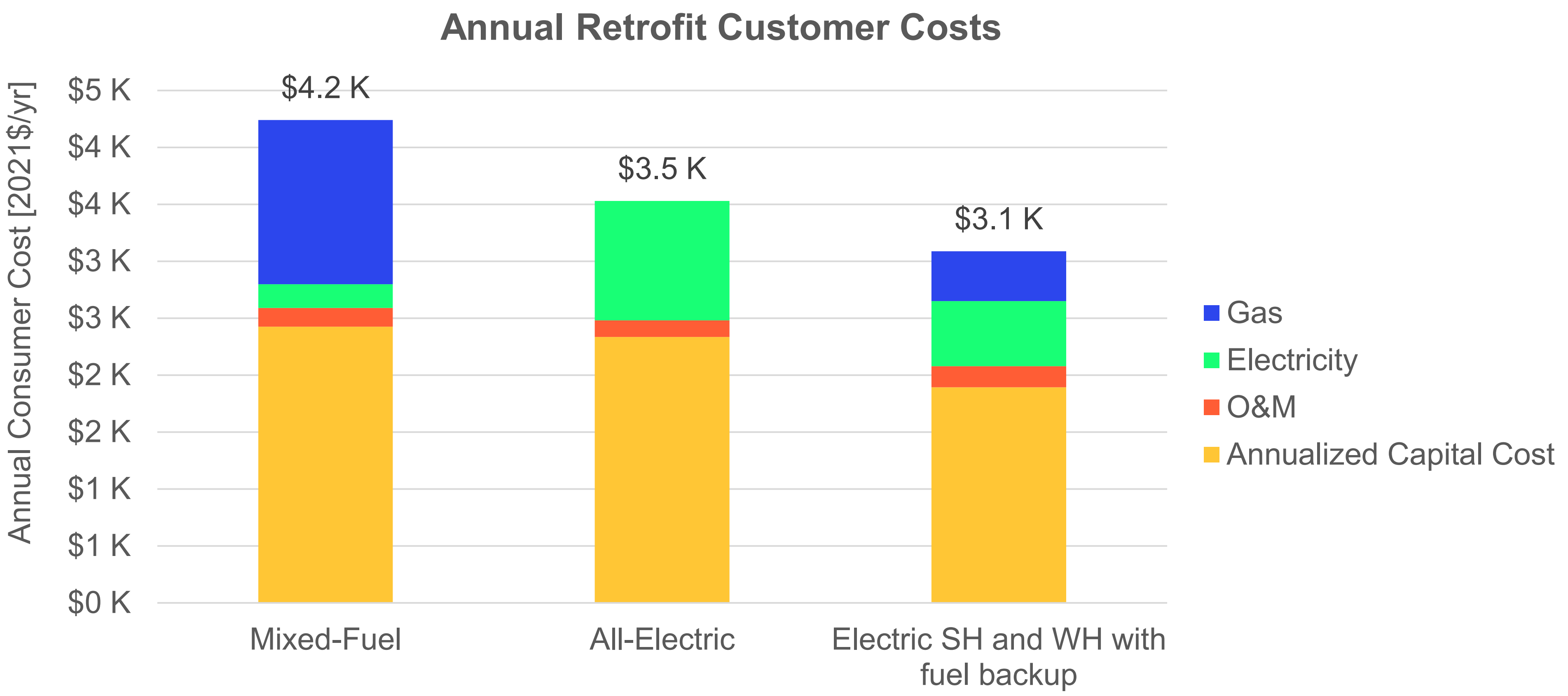
+ **All-electric new construction is cheaper than mixed-fuel new construction for large commercial buildings in a high electrification scenario and roughly cost neutral in all other decarbonization scenarios; By 2045, all-electric new construction is cheaper in every scenario**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent “optimistic” rate scenario (“conservative” gas scenario has 3% higher total cost for mixed-fuel)

When shell upgrade costs are removed from the Mixed-Fuel and All-Electric retrofits, electrifying heating with fuel backup is still expected to be the least expensive option for single family homes

+ **"Hybrid" customers can save money by utilizing their existing fuel-based heating equipment to provide backup heating during coldest hours of a year, and by not having to upgrade building shells**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates

STATE OF MARYLAND

PUBLIC SERVICE COMMISSION

December 29, 2023

President Bill Ferguson
H-107 State House
100 State Circle
Annapolis, MD 21401

Speaker Adrienne Jones
H-101 State House
100 State Circle
Annapolis, MD 21401

RE: Compliance with Sect. 10 of the Climate Solutions Now Act of 2022

Dear President Ferguson and Speaker Jones:

Section 10 of the Climate Solutions Now Act of 2022 (CSNA) requires the Public Service Commission (Commission) to complete a general system planning study to assess the capacity of each gas and electric company's distribution systems to successfully serve customers under a managed transition to a highly electrified building sector. The CSNA set Maryland on a course to achieve net zero greenhouse gas (GHG) emissions by 2045, and 60% GHG reduction by 2031 relative to 2006 levels. The Act includes provisions for extensive changes to various sectors including transportation, electricity, buildings, and agriculture. Further, the Act set the following requirements for this study:

- use a projection of average growth in system peak demand between 2021 and 2031 to assess the overall impact on each gas and electric distribution system
- compare future electric distribution system peak and energy demand load growth to historic rates
- consider the impacts of energy efficiency and conservation and electric load flexibility
- consider the capacity of the existing distribution systems and projected electric distribution system improvements and expansions to serve existing electric loads and projected electric load growth
- assess the effects of shifts in seasonal system gas and electric loads

The Maryland's Climate Pathway Report[1] demonstrates how Maryland can meet its ambitious climate goals of 60% reduction of greenhouse gas emissions by 2031 relative to 2006 levels, and attain a net-zero economy by 2045, all while realizing health and economic benefits

[1] *See* www.marylandsclimatepathway.com

WILLIAM DONALD SCHAEFER TOWER □ 6 ST. PAUL STREET □ BALTIMORE, MARYLAND 21202-6806

410-767-8000 □ Toll Free: 1-800-492-0474 □ FAX: 410-333-6495

MDRS: 1-800-735-2258 (TTY/Voice) □ Website: www.psc.state.md.us

for Marylanders, including improved air quality, new jobs, and household cost savings. This study modeled electrification scenarios that would result in direct building heating emissions reductions consistent with Maryland's Climate Pathway report.

The results indicate that the aggregate Maryland electric systems would see load growth rates in the range of 0.6–2.1% per year through 2031 with high electrification, assuming utility energy efficiency plans consistent with the Climate Solutions Now Act and existing utility demand response plans. This increase in load growth is accompanied by a 31–32% reduction in building sector gas demand by 2031 in high electrification scenarios. The Maryland electric distribution system, which is currently summer peaking, would switch to winter peaking around 2026–2027. Furthermore, additional energy efficiency and load flexibility measures could result in significant mitigation of load growth by 2031 to −0.2–1.2% per year. Historically, there was significant Maryland system load growth in the 1980s of 4.9% per year and more moderate growth of 1.2–1.5% from 1990–2010 while load declined between 2010–2020. These results show that peak load growth through 2031 with high electrification of the building sector will be comparable to or less than the growth rate the Maryland system has seen over the past 40 years.

This study provides system-level load growth projections to enable policymakers to understand and benchmark the impacts of different building decarbonization scenarios through 2031. While the study concludes that high levels of electrification can be handled by Maryland electric systems through 2031, consistent or lower than historical levels of Maryland load growth, the study does not quantify the costs and benefits of each scenario. Each scenario would result in several costs, including equipment installation and maintenance costs borne by building owners and grid investment and demand-side management program costs borne by utilities and utility ratepayers. Each scenario would also create several benefits, including fuel savings, avoided natural gas infrastructure investments, reduced societal impacts of GHG emissions, and reduced health impacts of air pollution.

It is also important to note that, while this study provides a utility system-level view of load growth trajectory under different scenarios, this study is not a substitute for more granular, locational distribution planning studies that could be conducted by the utilities. Through these studies, utilities will be able to plan specific upgrades to the distribution system based on the loading of existing equipment and forecasted customer adoption of various technologies.

Sincerely,

Frederick H. Hoover
Chair

cc: Chair Brian Feldman, Education, Energy and the Environment Committee
Chair C.T. Wilson, Economic Matters Committee
Chair Marc Korman, Environment and Transportation Committee
Eric Leudtke, Chief Legislative Officer

An Assessment of Electrification Impacts on the Maryland Electric Grid

PREPARED BY

Sanem Sergici
Akhilesh Ramakrishnan
Kate Peters
Ryan Hledik
J. Michael Hagerty
Ethan Snyder
Julia Olszewski
Hazel Ethier

PREPARED FOR

The Maryland Public Service Commission

WITH SUPPORT FROM

Applied Energy Group and Mondre Energy

DECEMBER 19, 2023

Brattle

NOTICE

This report was prepared for the Maryland Public Service Commission (PSC) in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts.

The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

While the analyses presented may assist Maryland PSC in rendering informed decisions, it is not meant to be a substitute for the exercise of PSC's own judgment. Neither we nor The Brattle Group will accept any liability under any theory for losses suffered, whether direct or consequential, arising from the reliance on the analyses presented, and cannot be held responsible if any conclusions drawn from this presentation should prove to be inaccurate.

There are no third-party beneficiaries with respect to this report, and The Brattle Group does not accept any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

ACKNOWLEDGMENTS

The authors would like to thank the members of the Electrification Study Working Group for participating in a collaborative process and making important contributions to the development of this study.

The authors would also like to extend their special thanks to Mr. John Borkoski, Senior Advisor with the Maryland Public Service Commission, for his excellent leadership and management of the working group process.

The authors would like to acknowledge excellent analytical and data support they received from the study partners Eli Morris and Kenneth Walter (Applied Energy Group) and Judith Mondre and Steven Miller (Mondre Energy).

TABLE OF CONTENTS

Key Takeaways

The Maryland's Climate Pathway Report demonstrates how Maryland can meet its ambitious climate goals of 60% reduction of greenhouse gas emissions by 2031 relative to 2006 levels, and attain a net-zero economy by 2045, all while realizing health and economic benefits for Marylanders, including improved air quality, new jobs, and household cost savings. This ***study modeled electrification scenarios that would result in direct building heating emissions reductions consistent with Maryland's Climate Pathway*** report.

The results indicate that the aggregate Maryland electric systems would see ***load growth rates in the range of 0.6–2.1% per year through 2031 with high electrification, assuming utility energy efficiency plans consistent with the Climate Solutions Now Act*** and existing utility demand response plans. This increase in load growth is accompanied by a ***31–32% reduction in building sector gas demand by 2031*** in high electrification scenarios. The Maryland electric distribution system, which is currently summer peaking, would switch to winter peaking around 2026–2027. Furthermore, ***additional energy efficiency and load flexibility measures could result in significant mitigation of load growth by 2031 to −0.2–1.2% per year***.

Historically, there was significant Maryland system load growth in the 1980s of 4.9% per year and more moderate growth of 1.2–1.5% from 1990–2010, while load declined between 2010–2020. These results show that ***peak load growth through 2031 with high electrification of the building sector will be comparable to or less than the growth rate the Maryland system has seen*** over the past 40 years.

Executive Summary

The Climate Solutions Now Act (CSNA),[1] passed into law in 2022, set Maryland on a course to achieve net zero greenhouse gas (GHG) emissions by 2045. In support of this goal, the Act stated the intent for Maryland to move toward electrification of the building sector, and directed the Maryland Public Service Commission ("PSC" or "Commission") to conduct a study "assessing the capacity of each company's gas and electric distribution systems to successfully serve customers under a managed transition to a highly electrified building sector." This study was developed to address the CSNA's directive to study the impacts of this transition through 2031.

This study assessed three high electrification scenarios that would result in reductions of direct greenhouse gas emissions from the building sector consistent with a pathway to meet the economy-wide goal of 60% reduction in emissions by 2031 relative to a 2006 baseline. These scenarios assume rapid electrification of the building sector, leading to 31–32% reduction of natural gas consumption and 27–28% reduction in liquid fuel (oil and propane) consumption in buildings by 2031 relative to 2022. All three scenarios also assume achievement of other key state decarbonization policies, including energy efficiency targets, the Renewable Portfolio Standard for electricity supply, the Advanced Clean Cars and Advanced Clean Trucks standards for vehicle sales, and the Building Energy Performance Standards for large buildings.

In a scenario where buildings electrify space and water heating primarily using less efficient heat pumps with resistive backup, results indicate that the aggregate Maryland electric system would see annual peak load growth of 2.1% through 2031. While these less efficient heat pumps are the most commonly used technology today, more efficient cold-climate heat pumps are commercially available and growing in market share.

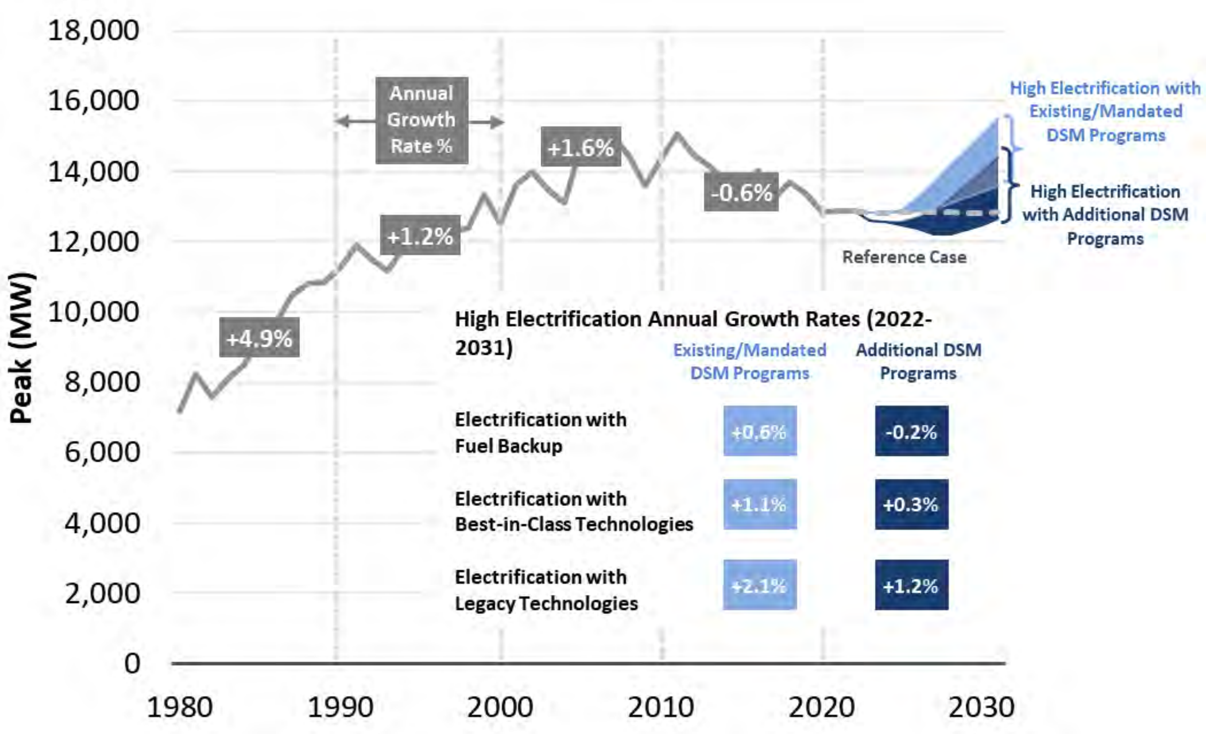
In a scenario where buildings electrify primarily using best-in-class cold climate heat pumps, the study projects an annual peak load growth of 1.1% through 2031. Cold-climate heat pumps can be sized to operate without backup and remain relatively efficient even at very low temperatures.

[1] Climate Solutions Now Act of 2022, Md. S.B. 528 (2022).

A "hybrid solution" to decarbonize buildings could consist of heat pumps operating for the majority of the year, with existing fossil fuel combustion equipment maintained as backup to operate during the coldest hours of the year. In a scenario where most buildings maintain and use their existing combustion equipment during the coldest hours, the study projects an annual peak load growth of 0.6% through 2031.

This projected range of 0.6–2.1% annual load growth assumes that utilities only implement demand-side management (energy efficiency and load flexibility) programs to mandated minimum levels. The study finds that load growth in high electrification scenarios can be further mitigated to −0.2 to 1.2% per year if utilities pursue additional demand-side management programs. Additional load flexibility programs could include managed EV charging, battery demand response, smart thermostat and smart water heater load control programs, and time-varying electricity rates.

FIGURE 1: HISTORICAL AND PROJECTED MARYLAND ANNUAL LOAD GROWTH



Sources and Notes: Maryland system peak loads are based on the total coincident peak of the six in-scope utilities. Historical load is backcasted using the 2022 peak load and the weighted average historical annual load growth of each utility. Historical growth rates are sourced from utility data if available or PJM zonal data for the corresponding zone. Projected load growth rates are based on utility load forecasts submitted for the 2022–2031 Ten Year Plan and Brattle modeling of the impacts of energy efficiency, behind-the-meter solar, load flexibility, transportation electrification, and building electrification.

Historically, there was significant load growth of 4.9% per year in Maryland in the 1980s and more moderate growth of 1.2 to 1.6% per year from 1990 to 2010. These historical load growth rates are indicators that the Maryland distribution utilities have successfully expanded capacity at growth rates comparable to or even higher than those projected in this study. Further, load declined between 2010 and 2020, implying that on average, existing utility distribution systems have capacity headroom to serve some load growth before system expansion would be required again.

This study provides system-level load growth projections to enable policymakers to understand and benchmark the impacts of different building decarbonization scenarios through 2031. While the study concludes that load growth through 2031 with high levels of electrification will be consistent or lower than historical levels of Maryland load growth, the study does not quantify the costs and benefits of electrification scenarios modeled. Each scenario would result in several costs, including equipment installation and maintenance costs borne by building owners and grid investment and demand-side management program costs borne by utilities and utility customers. Each scenario would also create several benefits, including fuel savings, avoided natural gas infrastructure investments, reduced societal impacts of greenhouse gas emissions, and reduced health impacts of air pollution.

It is also important to note that, while this study provides a utility system-level view of load growth trajectory under different scenarios, it does not identify exactly the timing, location, and magnitude of utility distribution system upgrades that may be needed. It is plausible that electrification may be concentrated on the parts of the distribution network with limited headroom for some of the in-scope utilities, and that these distribution assets will need more immediate upgrades than others. Therefore, this study is not a substitute for more granular, locational distribution planning studies that could be conducted by the utilities. Through these studies, utilities will be able to plan specific upgrades to the distribution system based on the loading of existing equipment and forecasted customer adoption of various technologies.

I. Introduction

The Climate Solutions Now Act (CSNA) set Maryland on a course to achieve net zero greenhouse gas (GHG) emissions by 2045, and 60% GHG reduction by 2031 relative to 2006 levels. The Act includes provisions for extensive changes to various sectors including transportation, electricity, buildings, and agriculture. Among provisions related to the buildings sector, the Act stated the intent for the State to "move toward broader electrification of both existing buildings and new construction," and directed the Maryland Public Service Commission ("PSC" or "Commission") to conduct this study to assess the electric and gas distribution system impacts of a managed transition to a highly electrified building sector. Further, the Act set the following requirements for this study:

- Use a projection of average growth in system peak demand between 2021 and 2031 to assess the overall impact on each gas and electric distribution system;
- Compare future electric distribution system peak and energy demand load growth to historic rates;
- Consider the impacts of energy efficiency and conservation and electric load flexibility;
- Consider the capacity of the existing distribution systems and projected electric distribution system improvements and expansions to serve existing electric loads and projected electric load growth; and
- Assess the effects of shifts in seasonal system gas and electric loads.

The Commission convened the Electrification Study Working Group to advise on the study, and engaged The Brattle Group to conduct the study, with assistance from Applied Energy Group and Mondre Energy. This Executive Summary Report outlines the framework and key findings of the study. Further details on the analytical methodology, assumptions, inputs, data sources, and results are provided in the accompanying Technical Appendix.

A. Scope of This Study

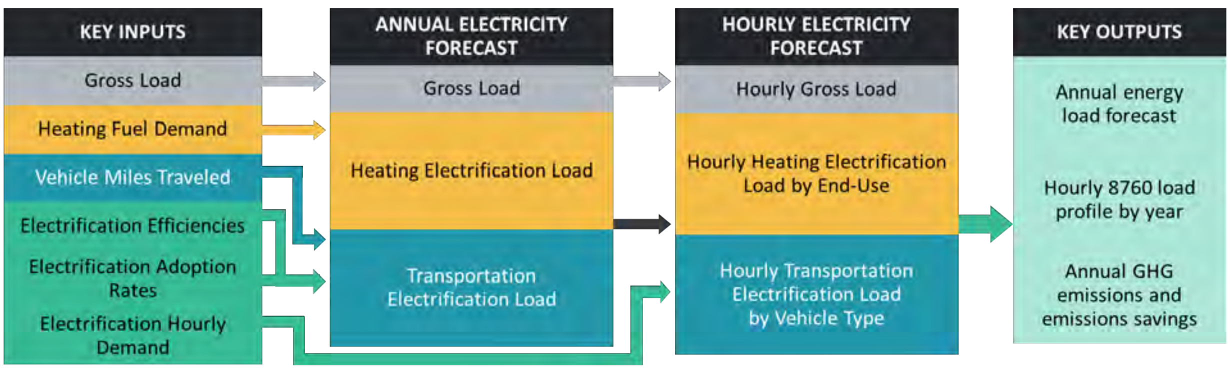
Per CSNA directives, the main objective of the study is to model the impact of building electrification on system average load growth for in-scope gas and electric utilities.

In-Scope Electric Utilities: Baltimore Gas and Electric (BGE), Choptank Electric, Delmarva Power (DPL), Pepco, Potomac Edison, Southern Maryland Electric Cooperative (SMECO)

In-Scope Natural Gas Utilities: Baltimore Gas and Electric (BGE), Columbia Gas of Maryland, Washington Gas Light (WGL) Maryland

Each in-scope utility system was modeled **using Brattle's Decarbonization, Electrification, and Economic Planning (DEEP) Model**. The model provides in-depth projections of electric load based on input scenarios detailing the uptake over time of heat pumps, electric vehicles, distributed energy resources (DERs), energy efficiency, and load flexibility. The model also quantifies changes to fossil fuel demand, including changes to natural gas, fuel oil, propane, and motor gasoline consumption, and associated direct GHG emissions.

FIGURE 2: BRATTLE'S DEEP MODEL FRAMEWORK



Sources and Notes: The DEEP model was calibrated to each in-scope utility system. It included a detailed characterization of each system in terms of the forecasted growth of non-electrification related loads; the existing number of types of equipment used by customers for heating, cooling, transportation, and distributed generation; and energy demand associated with each of these end uses. The model then produces hourly electric loads associated with each end use and appliance type through 2031, using assumptions on appliance efficiencies, usage, and the evolution of the fuel mix over time as customers adopt new technologies.

The DEEP model was used to project the impacts of stakeholder-defined scenarios centered on different possible rates of electrification and demand-side management (DSM). The modeled scenarios are described in Section II.

The projections of hourly electricity load through 2031 for each electric utility in each scenario are used to assess the impacts of a highly electrified building sector. The results are used to identify the rate of utility system average peak load growth as well as the timing of changes to summer and winter loads. Projected load growth rates are then compared to historical load growth rates managed by each utility from 1980–2020 to provide a benchmark for the severity of load impacts. Finally, the geographical overlap of each electric utility with each gas utility service territory is used to project changes to each gas utility's demand in each scenario.

Several proposed, ongoing, or recently concluded studies, proceedings, and rulemakings were used to inform the framework as well as assumptions used in this study. Key sources of information include the following:

The Maryland Department of Environment (MDE) Climate Pathway Study[2] is used primarily to inform this study on the GHG reduction contribution required from the building sector in order for Maryland as a whole to meet the 60% by 2031 GHG reduction goal.

The Maryland GHG Abatement Study[3] was completed in 2023 as part of EmPOWER Maryland ("EmPOWER") proceedings, and is used to inform this study on the existing mix of heating and cooling equipment types used by customers in each utility service territory.

EmPOWER 2024–2026 Program Cycle Utility Filings[4] were submitted by each EmPOWER utility in August 2023, and are used to inform this study on the expected electricity savings from energy efficiency programs.

The Maryland Renewable Portfolio Standard (RPS) Study[5] is an ongoing study being conducted by the Power Plant Research Program, and is used to inform this study on the capacity of behind-the-meter solar and storage resources that can be expected to be installed through 2031.

The Advanced Clean Cars (ACC) II Rule[6] was adopted by MDE in 2023 and requires vehicle manufacturers to gradually increase the zero-emission vehicle (ZEV) share of their total car sales to 100% by 2035. This study uses the Rule's annual targets to inform growth in EV sales.

---

2 Kennedy, Kathleen M. et al. "Maryland's Climate Pathway." Center for Global Sustainability, University of Maryland, June 2023. https://cgs.umd.edu/sites/default/files/2023-09/file_final_Maryland%27s Climate Pathway Report.pdf

3 Applied Energy Group (AEG) EmPOWER Maryland. "2024–2029 Greenhouse Gas Abatement Potential Study Final Report." Case No. 9648 ML #300751, Potomac Electric Power Company filed, on January 06, 2023.

4 Maryland EmPOWER Utilities, Maryland Department of Housing, and Community Development (DHCD). "The 2024-2026 EmPOWER Maryland Program." Case No. 9705, ML #303381, June 7, 2023. https://webpsc.psc.state.md.us/DMS/case/9705

5 Maryland Department of Natural Resources. "Maryland 100% Study." https://dnr.maryland.gov/pprp/Pages/maryland-100percent-study.aspx

6 Maryland Department of the Environment. "Advanced Clean Cars II." https://mde.maryland.gov/programs/air/MobileSources/Pages/Clean-Energy-and-Cars.aspx#:~:text=%E2%80%8BWhat%20is%20Advanced%E2%80%8B%E2%80%8B%20Clean%20Cars%20II&text=By%20adopting%20ACC%20II%20in,to%20reduce%20smog%2Dforming%20emissions.

The Advanced Clean Trucks (ACT) Rule[7] is similar to the ACC II Rule and requires vehicle manufacturers to gradually increase the ZEV share of their total medium/heavy duty vehicle sales by 2035 to 55% of Class 2b—3 truck sales, 75% of Class 4—8 straight truck sales, and 40% of truck tractor sales. The Advanced Clean Trucks Act, passed in 2023, directed MDE to adopt the ACT Rule. This study uses the Rule's annual targets to inform growth in EV sales.

The Building Energy Performance Standard (BEPS)[8] is proposed by MDE under the directive of the CSNA to require buildings over 35,000 sq. ft. to net-zero direct GHG emissions by 2040. This study uses the requirements of the BEPS to inform the assumed rate of electrification of buildings over 35,000 sq. ft.

B. Related Matters Outside the Scope of this Study

The transition to a highly electrified building sector is complex and multifaceted. Each facet merits detailed study during the process of policy development and implementation. This study is intended to inform policymakers regarding one facet of the transition—the impacts on electricity and natural gas demand through 2031.

This study does not address other important transition issues, including but not limited to:

- Cost-effectiveness of building electrification;
- The technical feasibility and commercial availability of electrification technologies for various types of customers;
- Locational distribution system upgrades that may be needed to support new load;
- Locational non-wire solutions that may defer distribution system upgrades;
- Potential decommissioning of parts of the gas delivery system as customers electrify;
- Regulatory mechanisms to sustainably manage gas utilities as gas throughput declines;
- Environmental justice and equity to ensure that disadvantaged communities are not left behind in the transition.

[7] Maryland Department of the Environment. "Facts about Adoption of COMAR 26.11.43 Advanced Clean Trucks Program." June 12, 2023. https://mde.maryland.gov/programs/regulations/air/Documents/Hearings/2023 ACT Fact Sheet.pdf

[8] Maryland Department of the Environment. "Building Energy Performance Standards." https://mde.maryland.gov/programs/air/ClimateChange/Pages/BEPS.aspx

II. Study Scenarios

A. Scenario Definitions

TABLE 1: SCENARIO DEFINITIONS

	Decarbonization Policy Goals Not Pursued		Pursuit of Policy Goals through Hybrid Solutions		Pursuit of Policy Goals through Zero Direct Emissions Solutions	
	Reference	**Low Electrification Scenario[1]**	**Mid Electrification Scenario[1]**	**High Electrification with Fuel Backup Scenario**	**High Electrification with Best-in-Class Technologies Scenario**	**High Electrification with Legacy Technologies Scenario**
Description	"Reference" for load impacts of other scenarios. Defined as the state of the world as implied by each utility's current load forecast.	Limited incremental electrification. Assumes policy goals are not met.	Mix of electrification and continued use of fuels.	High electrification with retention of existing fossil fuel equipment for backup.	Fossil fuel equipment is phased out through policy. Customers quickly adopt more advanced, efficient electric technologies.	Fossil fuel equipment is phased out through policy. Customers are slower to adopt more advanced, efficient electric technologies.
Buildings	**Fuel mix held flat** from 2022.	**Limited incremental electrification** (majority of existing gas and fossil customers do not adopt heat pumps).	**Fossil fuel equipment sales continue beyond 2030;** some customers switch to heat pumps.	By 2030, all new equipment sales are HPs. **Almost all existing customers retain their fossil fueled equipment as backup.**	By 2030, all new equipment sales are HPs.[2] **Most HPs are highly efficient ccASHPs.[3]**	By 2030, all new equipment sales are HPs.[2] **Most HPs are less efficient ASHP+resistance backup.**
Distributed Energy Resources	Distributed Energy Resources (DER) growth in line with RPS mandate.					
Transportation	Based on EIA projections.	3-year delay relative to ACC II and ACT.	Achievement of Advanced Clean Cars II (ACC II) and Advanced Clean Trucks (ACT) regulations.			
Demand-Side Management	For each scenario, we run two DSM cases: 1. **Existing/Mandated DSM Programs Only** 2. **Additional DSM Programs (i.e., new programs and growth of existing programs)**					

1 The Low and Medium Electrification Scenarios were modeled in this study but are not discussed in this report, as they are inconsistent with a pathway to meeting the state's climate goals. 2 With some exceptions for the hardest-to-electrify cases (we assume around 5% of sales will be exempt from the policy and remain as fossil fuel equipment sales); 3 ccASHP = cold climate air-source heat pump, ASHP = air-source heat pump.

Per the CSNA directive to study a "managed transition to a highly electrified building sector," the three scenarios discussed in this report assume high electrification of space and water heating in residential and commercial buildings. The study included modeling of two other scenarios—Low Electrification and Medium Electrification—that did not result in GHG emission reductions sufficient to meet Maryland's climate goals. Those scenarios are not discussed in this report. Assumptions and results related to those two scenarios are provided in the Technical Appendix. All of the scenarios, inputs, assumptions, and data sources were developed with close collaboration and review from stakeholders in the Electrification Study Working Group.

In this study's high electrification scenarios, high electrification is defined as a transition to all new heating equipment sales being heat pumps by 2030, with very limited exceptions. While this is an ambitious trajectory, it is consistent with the pace of decarbonization required to meet Maryland's climate goals, for at least three reasons:

- Due to the long lifetime of heating equipment (15–25 years), new equipment installed in 2030 will likely still be in operation in 2045, and therefore must be zero-emission in order for Maryland to meet its goal of net-zero emissions by 2045
- MDE's Climate Pathway Study identified that a 35% reduction of building sector emissions by 2031 relative to 2006 would be required for the state to meet the economy-wide goal of 60% emission reduction by 2031, relative to 2006. This is in parallel to decarbonization of other key sectors like electricity, transportation, and industry.
- Further, the MDE Climate Pathway Study showed that a zero-emission appliance standard for space and water heating by 2030 would result in the building sector emission reductions needed to meet the 2031 and 2045 climate goals.

As a result, all three high electrification scenarios modeled in this study were benchmarked against the Climate Pathway Study to ensure consistency with meeting Maryland's 2031 climate goal.

Electrification at such a pace likely requires policies to incentivize and/or require customer adoption of zero-emission technologies. Regulations to achieve this transition to zero-emission heating can take many forms. For example, the Building Energy Performance Standard proposed by MDE would penalize large buildings over 35,000 square feet for emissions above a cap that declines over time. Similar zero-emission standards could be implemented for smaller buildings, as envisioned in MDE's Climate Pathway Study, to accelerate the transition of residential and small commercial buildings.

While all three high electrification scenarios in this study assume a similar pace of building electrification, the key distinction between the scenarios is in the primary configuration or type of heat pumps used to electrify buildings. The study considers three heating electrification scenarios:

Electrification with Fuel Backup: In this scenario, most customers currently heating with fossil fuels are assumed to maintain their fossil fuel equipment for use during the coldest hours of the year, even after adopting a heat pump. The advantage of this solution is that peak electric heating loads, which occur during the coldest hours, can be mitigated by switching to fossil fueled heat, while limiting emissions by operating heat pumps in all other hours. However, it requires maintenance (and eventually, replacement) of two sets of heating equipment, in addition to ongoing maintenance and investment in fossil fuel infrastructure.

Electrification with Best-in-Class Technologies: In this scenario, most customers are assumed to adopt highly efficient cold-climate air-source heat pumps (ccASHPs). Modern cold-climate heat pumps operate at relatively high efficiencies even at very cold temperatures and can be sized to meet peak heating demands without inefficient resistive heating backup. This scenario also assumes a higher penetration of ground source heat pumps (GSHPs) than the other two scenarios.

Electrification with Legacy Technologies: In this scenario, most customers are assumed to adopt lower efficiency air source heat pumps (ASHPs), with resistive heating backup elements to serve heating demands during the coldest hours. These systems may be cheaper than newer, more efficient heat pumps, but add significant electric load due to their low efficiency at very cold temperatures.

Table 1 summarizes the study scenarios based on the key changes modeled within the building sector, transportation sector, distributed energy resources (DERs), and demand-side management (DSM). All of the modeled scenarios build from the Reference Case, which is defined primarily using the 2022–2031 load forecasts provided by each utility in the 2022–2031 Ten Year Plan of Electric Companies in Maryland.[9] The Reference Case assumes no change to the fuel mix of the building sector and very limited transportation electrification, and is

[9] Public Service Commission of Maryland. “Ten-Year Plan (2022-2031) of Electric Companies in Maryland.” https://www.psc.state.md.us/wp-content/uploads/2022-2031-Ten-Year-Plan-Final.pdf. Some adjustments were made to the utility forecasts to align all 6 in-scope utilities’ EV and DER assumptions in the Reference Case.

intended to capture load growth from factors unrelated to decarbonization, such as economic growth and population migration.

In order to isolate the impacts of different building electrification scenarios, the other key modeled sectors, transportation and DERs, were held constant across the electrification scenarios. All three high electrification scenarios assume vehicle sales follow the trajectories set by the Advanced Clean Cars II[10] and Advanced Clean Trucks[11] rules, which require vehicle manufacturers to gradually increase their fraction of zero-emission vehicle sales. The Advanced Clean Cars II rule requires 100% zero-emission light duty vehicle (LDV) sales by 2035, and the Advanced Clean Trucks rule requires 40–75% zero-emission sales across different medium/heavy duty vehicle (MHDV) classes by 2035. All three scenarios also assume DER capacity grows in line with the trajectory modeled by the Maryland RPS Study. Recent trends in distributed solar adoption suggest that rates of adoption are on track for RPS compliance.

Demand-side management through energy efficiency and load flexibility programs can be highly effective at mitigating load growth. To assess the impact of DSM, the study considers two DSM cases for each scenario:

Existing/Mandated DSM: This case assumes annual energy efficiency savings consistent with utility plans that meet the minimum requirements set forth by the CSNA. It assumes only existing utility demand response programs continue through 2031. The modeling in this case assumes that both mandated energy efficiency and existing demand response programs are already factored into utility load forecasts, and therefore does not adjust forecasts further for DSM.

Additional DSM: This case assumes significant additional energy efficiency, consistent with deployment of all cost-effective energy efficiency measures. It also assumes the introduction of new load flexibility programs, such as managed EV charging, and enrollment and participation of an ambitious but plausible fraction of customers in these programs.

10 California Air Resource Board. "Advanced Clean Cars II." https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/advanced-clean-cars-ii

11 "Final Regulation Order: Advanced Clean Trucks Regulation." https://ww2.arb.ca.gov/sites/default/files/2023-06/ACT-1963.pdf

B. Customer Adoption of Technologies by 2031

The study models the turnover of equipment stock in the transportation and building sectors as customers replace their existing equipment at the end of its average useful lifetime. Based on the definitions of each of the three scenarios, the mix of new equipment sales is assumed to change over time to reflect fuel-switching. However, the long lifetime of transportation and heating equipment means changes in the mix of new equipment sales take many years to lead to significant changes in the mix of the total installed stock of equipment. For example, an appliance having an average lifetime of 20 years implies that only 5% of customers replace their equipment in a given year. Table 2 through Table 5 summarize the assumed mix of new equipment sales and resulting changes to total installed equipment stock in 2031. Aggregate Maryland level figures are summarized here, and detailed utility level inputs and data sources are provided in the Technical Appendix.

TABLE 2: RESIDENTIAL SPACE AND WATER HEATING NEW SALES AND STOCK PROJECTIONS

	2022	2031							
	Current	Reference		Fuel Backup		Best Tech.		Legacy Tech.	
	Penetration	Sales	Stocks	Sales	Stocks	Sales	Stocks	Sales	Stocks
Residential Space Heating									
Gas	43%	43%	43%	3%	29%	3%	29%	3%	29%
Liquid Fuel	8%	8%	8%	1%	6%	1%	6%	1%	6%
ASHP + Fuel	5%	5%	5%	43%	18%	0%	3%	0%	3%
Electric Resistance	22%	22%	22%	0%	14%	0%	14%	0%	14%
ASHP + Resistance	17%	17%	17%	32%	22%	0%	11%	57%	32%
ccASHP	3%	3%	3%	16%	8%	82%	31%	29%	12%
GSHP	2%	2%	2%	5%	3%	14%	7%	10%	5%
Residential Water Heating									
Gas	35%	35%	35%	4%	20%	4%	20%	4%	20%
Liquid Fuel	3%	3%	3%	0%	2%	0%	2%	0%	2%
Resistance	55%	55%	55%	25%	48%	5%	29%	25%	48%
Heat Pump	6%	6%	6%	70%	30%	91%	49%	70%	30%

Sources and Notes: "Best Tech." refers to the Electrification with Best-in-Class Technologies Scenario and "Legacy Tech." refers to the Electrification with Legacy Technologies Scenario. The Reference Case assumes customers replace their existing space and water-heating equipment with the same technology at the end of its lifetime, meaning the installed mix of equipment in 2031 is identical to today. All three High Electrification Scenarios assume heat pump sales grow rapidly to meet a zero-emission standard for new space and water heating equipment sales by 2030, similar to modeling by MDE in the Climate Pathway Report. Delivered fuel and standalone gas equipment sales fall to almost zero, assuming regulations allow limited exceptions. The scenarios differ in terms of the mix of heat pump configurations adopted by customers. Sales and stocks are expressed as % of households.

TABLE 3: COMMERCIAL SPACE AND WATER HEATING NEW SALES AND STOCK PROJECTIONS

	2022	2031							
	Current	Reference		Fuel Backup		Best Tech.		Legacy Tech.	
	Penetration	Sales	Stocks	Sales	Stocks	Sales	Stocks	Sales	Stocks
Commercial Space Heating									
Gas	50%	50%	50%	3%	32%	3%	32%	3%	32%
Liquid Fuel	6%	6%	6%	1%	4%	1%	4%	1%	4%
ASHP + Fuel	0%	0%	0%	45%	17%	8%	3%	8%	3%
Electric Resistance	33%	33%	33%	1%	21%	1%	21%	1%	21%
ASHP + Resistance	10%	10%	10%	31%	18%	0%	6%	53%	27%
ccASHP	0%	0%	0%	15%	6%	74%	29%	26%	10%
GSHP	1%	1%	1%	5%	2%	13%	6%	9%	4%
Commercial Water Heating									
Gas	33%	33%	33%	3%	21%	3%	21%	3%	21%
Liquid Fuel	1%	1%	1%	0%	1%	0%	1%	0%	1%
Resistance	60%	60%	60%	15%	44%	4%	37%	15%	44%
Heat Pump	6%	6%	6%	81%	34%	93%	41%	81%	34%

Sources and Notes: "Best Tech." refers to the Electrification with Best-in-Class Technologies Scenario and "Legacy Tech." refers to the Electrification with Legacy Technologies Scenario. The Reference Case assumes customers replace their existing space and water heating equipment with the same technology at the end of its lifetime, meaning the installed mix of equipment in 2031 is identical to today. In the three High Electrification Scenarios, commercial buildings electrification is assumed to progress at a different pace for small commercial buildings (which are not covered by the BEPS) and large commercial buildings (which are covered by the BEPS). Smaller commercial buildings are assumed to follow a similar trajectory to residential buildings, with heat pump sales growing rapidly to meet a zero-emission standard for new space and water heating equipment sales by 2030, similar to modeling by MDE in the Climate Pathway Report. Delivered fuel and standalone gas equipment sales fall to almost zero, assuming regulations allow limited exceptions. Larger commercial buildings are assumed to electrify at a pace sufficient to comply with the BEPS based on modeling in the Climate Pathway Report. Sales and stocks are expressed as % of commercial square feet.

TABLE 4: ELECTRIC VEHICLE NEW SALES AND STOCK PROJECTIONS

	2022	2031			
	Current	Reference		High Electrification	
	Penetration	Sales	Stocks	Sales	Stocks
Electric Vehicles					
LDV	1%	20%	8%	76%	23%
Class 2B-3	0%	0%	0%	35%	8%
Class 4-8	0%	0%	0%	55%	13%
Class 7-8 Tractor	0%	0%	0%	35%	8%
School Bus	1%	0%	1%	55%	13%

Sources and Notes: The Reference Case assumes very limited growth in transportation electrification, consistent with the EIA's Annual Energy Outlook. All three High Electrification Scenarios assume the same level of transportation electrification, consistent with meeting the requirements of the Advanced Clean Cars and Advanced Clean Trucks regulations that have been adopted in Maryland. Sales and stocks are expressed as % of vehicles.

TABLE 5: MARYLAND BEHIND-THE-METER DISTRIBUTED ENERGY RESOURCE FORECASTS (MW)

	2022	2031
Solar	1,204	2,290
Storage	40	518

Sources and Notes: All three High Electrification Scenarios and the Reference Case assume the same level of growth of distributed energy resources (DERs) in line with RPS achievement as projected in the PPRP RPS Study.[12] Behind-the-meter storage in the Existing/Mandated DSM Program Cases does not affect peak load, since no utilities currently have battery storage demand response programs. The Additional DSM Programs Cases assume that utilities use BTM storage to manage peak load through demand response programs described below.

C. Demand Side Management (DSM)

Within each scenario, the study models two different portfolios of DSM programs to study the potential load mitigation impacts of additional DSM.

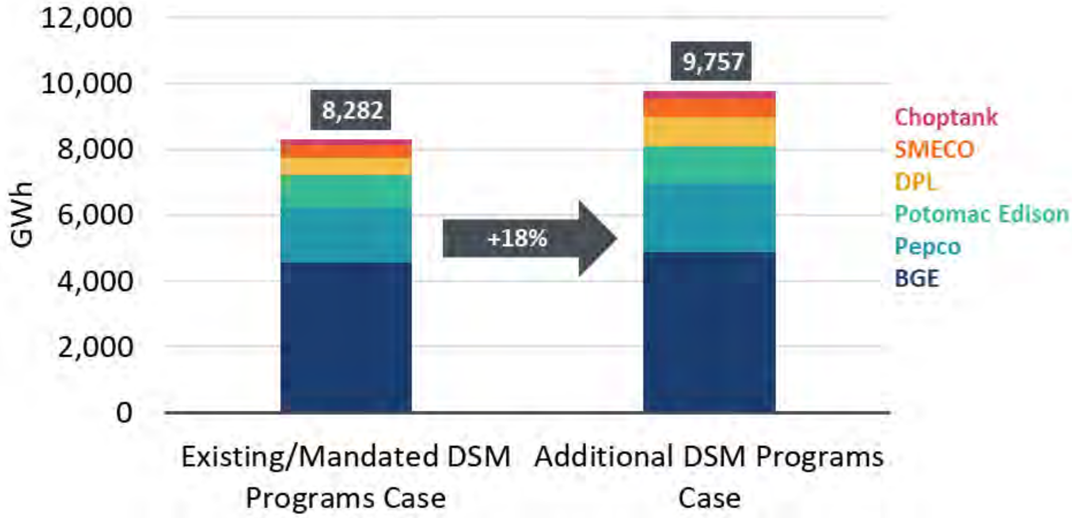
1. Energy Efficiency

Energy Efficiency assumptions are based on the EmPOWER 2024–2026[13] program cycle plans filed by utilities in August 2023. The Existing/Mandated DSM Programs Case assumes utilities achieve the "2023 Scenario" level of Energy Efficiency from these filed plans, which is based on achievement of minimum statutory requirements. The Additional DSM Programs Case assumes utilities adopt EE programs consistent with their filed "Maximum Achievable Scenarios," defined as the set of programs and measures that result in maximum cost-effective savings. Annual savings from 2027 to 2031 were assumed to be the same as 2026 savings. By 2031, Maryland-wide Energy Efficiency savings are 18% higher in the Additional DSM Programs case than the Existing/Mandated case.

12 Maryland Department of Natural Resources. "Maryland 100% Study." https://dnr.maryland.gov/pprp/Pages/maryland-100percent-study.aspx

13 Maryland Public Service Commission. "Energy Efficiency and EmPOWER Maryland." https://www.psc.state.md.us/electricity/empower-maryland/

FIGURE 3: ANNUAL ENERGY EFFICIENCY SAVINGS (GWH) IN 2031



Sources and Notes: The figure shows the 2031 savings from energy efficiency programs for the Existing/Mandated and Additional DSM Programs Cases. Program savings are sourced from EmPOWER 2024–2026 filed plans, which provide one case aligned with minimum mandates and another case aligned with maximum achievable cost-effective savings. Annual savings from 2027–2031 are assumed to be the same as in 2026. Adjustments were made to remove heating and cooling programs from energy efficiency portfolios, as these measures are modeled separately in this study.

2. Load Flexibility

The Existing/Mandated DSM Programs Case assumes utilities continue existing load flexibility programs at the same participation levels through 2031. The Additional DSM Programs Case assumes increased participation in existing programs and the deployment of new load flexibility programs using BTM storage, managed electric vehicle charging, expanded time-varying rates, and others described in Table 6.

TABLE 6: LOAD FLEXIBILITY PROGRAMS AND 2031 PARTICIPATION (% OF ELIGIBLE CUSTOMERS)

Program	Description	Existing Participation[14]	Additional Case Participation
Residential			
Time-of-use (TOU)	Time varying pricing signals, consistent with proposed utility rates	0%	15%
Peak time rebate (PTR)	Residential customers reduce load during called event hours	BGE, Pepco, DPL: 90% SMECO, Choptank, Potomac Edison: 0%	90%
Smart thermostat	Customers reduce cooling or heating load by adjusting thermostats during utility called events (<20/yr)	Summer: BGE (28%); Pepco (38%); DPL (20%); SMECO, Choptank, Potomac Edison (0%) Winter: 0% for all utilities	Summer (~+25%pt from existing): BGE (55%); Pepco (65%); DPL (45%); SMECO, Choptank, Potomac Edison (25%) Winter: 25% for all utilities
Smart water heating	Customers shift heat water during off peak hours on a frequent (daily) basis	0%	30%
Commercial			
Smart thermostat	Small commercial customers reduce cooling or heating load by adjusting thermostats during utility called events (<20/yr)	0%[15]	25%
Automated demand response (DR) – HVAC	Automated control of customer heating and cooling demand. Only applicable to large (Covered) customers	0%	10%
Interruptible tariff	Large customers (Covered) reduce load during called events. Events are infrequent (<10/yr)	0%	15%
Additional Programs			
Managed electric vehicle charging	Customers are incentivized to charge in off peak hours and shift EV load out of daily peak periods	0%	30% (all vehicle classes)
Behind-the-meter battery storage	Utilities can call on batteries to charge and discharge during event hours (70 events/yr). Assume only a portion of BTM storage capacity from the PPRP study enrolls in utility programs	0%	30% of BTM storage capacity

Sources and Notes: The Existing/Mandated DSM case assumes utilities continue to operate existing load flexibility programs at current participation levels. These existing programs are comprised mainly of smart thermostats and time-varying rates. The Additional Case participation assumes increasing participation in existing programs, in addition to the introduction new programs. These participation rates were informed by a review[16] of comparable programs deployed in other jurisdictions, representing aggressive but achievable enrollment.

III. Key Results

The Brattle Group's DEEP Model[17] was used to evaluate the impacts of each electrification scenario on fossil fuel consumption, electricity demand, and emissions at the utility system level. This section summarizes key results for the three high electrification scenarios at the aggregated Maryland level and then highlights differences between utility regions. The Low and Medium Electrification scenarios are not discussed as they are inconsistent with achievement of Maryland's GHG goals. Detailed annual results by utility for all modeled scenarios are available in the Technical Appendix.

A. Reductions in Fossil Fuel Consumption

Electrification of the building sector results in significant reductions in liquid fuel (fuel oil and propane) and natural gas consumption. Figure 4 shows that the modeled rate of electrification would reduce fossil fuel consumption for space and water heating by 31–32% relative to 2022.

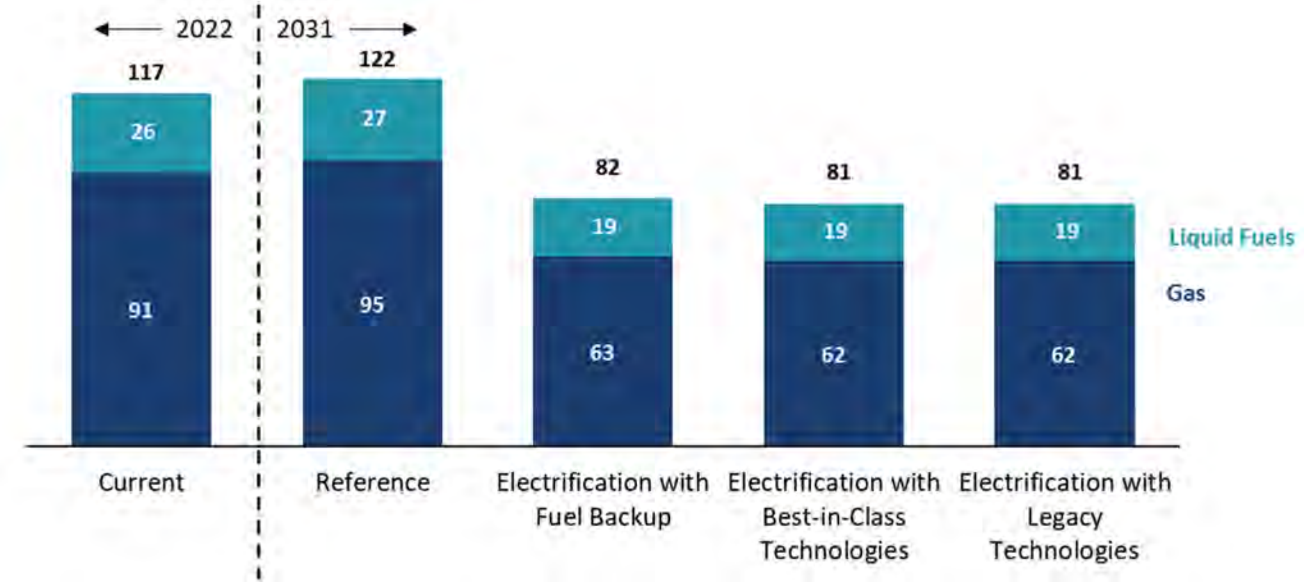
[14] Participation assumptions for existing load flexibility programs are sourced from utility EmPOWER filings. Maryland Public Service Commission. "Energy Efficiency and EmPOWER Maryland." https://www.psc.state.md.us/electricity/empower-maryland/

[15] Pepco and DPL have commercial smart thermostat programs, but participation is negligible.

[16] National Roadmap for Grid Interactive Efficient Buildings, The Brattle Group

[17] Modeling methodology and detailed assumptions and inputs are provided in the Technical Appendix.

FIGURE 4: FOSSIL FUEL CONSUMPTION FOR SPACE AND WATER HEATING IN MARYLAND
Million MMBTU per Year

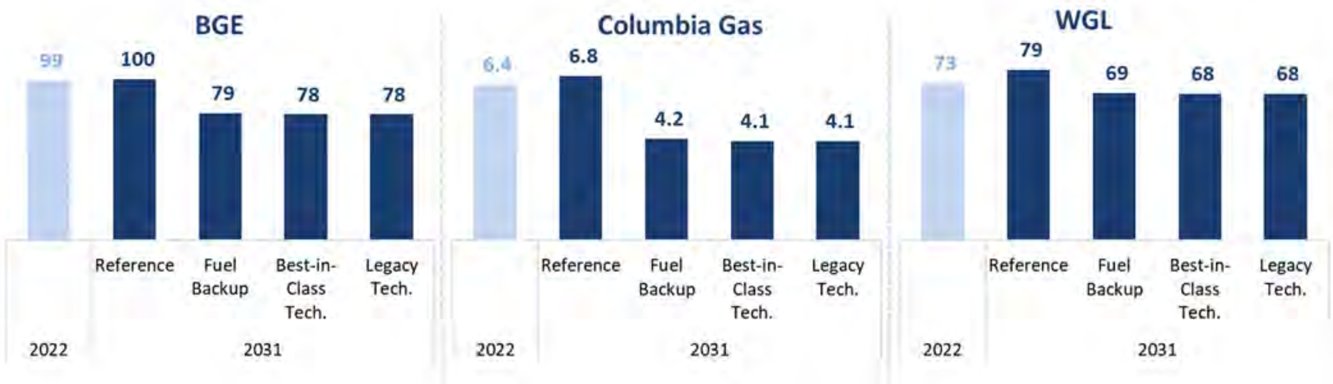


Sources and Notes: 2022 consumption of liquid fuels and natural gas are based on EmPOWER GHG abatement study data. The Reference Case is based on customer growth and the assumption that the percentage of customers using each fuels remains unchanged. The Electrification scenarios are based on the modeled shift of customers to heat pumps over time.

There are only minor differences in fossil fuel consumption across electrification scenarios as all three scenarios model a switch to 100% heat pump sales (when a customer installs a new heating unit) by 2030. The Fuel Backup scenario has slightly higher fuel consumption as heat pump customers continue to serve roughly 7% of their annual heating demand by operating their fossil fuel equipment in the 170 coldest hours of the year.

The 31-32% reduction in natural gas consumption for space and water heating end uses translates to a 19% reduction in total gas delivered in 2031 by the Maryland gas utilities relative to the Reference Case.

FIGURE 5: TOTAL NATURAL GAS DEMAND, BY UTILITY
Million MMBTU



Sources and Notes: "Best-in-Class Tech." refers to the Electrification with Best-in-Class Technologies Scenario and "Legacy Tech." refers to the Electrification with Legacy Technologies Scenario. 2022 and Reference Case 2031– natural gas demand are based on each utility's load forecast. Since WGL's forecast ends in 2027, Reference Case 2031 load was projected by Brattle based on WGL's forecasted 2020–2027 load growth rate. 2031 natural gas demand in the Electrification scenarios is based on the modeled reduction in gas usage for space and water heating relative to Reference. None of the other end uses of natural gas (e.g., industrial) are assumed to change in this study.

B. Reductions in GHG Emissions

The MDE Climate Pathway Study identified a pathway to achieving Maryland's 2031 climate goal that involves a 30% reduction in direct emissions from space and water heating in buildings from 2022 levels. Table 7 shows that each of the three modeled electrification scenarios approximately meet this 30% direct emission reduction target. The Fuel Backup scenario involves marginally higher emissions than the other two scenarios due to the direct emissions of the fossil fuel equipment used to provide backup during the coldest hours of the year.

Because this study is focused on the building sector, it does not attempt to repeat the economy-wide emissions modeling completed in the MDE Climate Pathway Study. Instead, this study benchmarks space and water heating emissions to the MDE study to ensure that the modeled building sector pathway is consistent with a broader economy-wide pathway to meeting Maryland's climate goal. Sectors that are outside the scope of this study, such as electricity generation and industry, must decarbonize at the pace modeled in MDE's study for the economy-wide goal to be achieved.

TABLE 7: DIRECT EMISSIONS FROM SPACE AND WATER HEATING EQUIPMENT (MILLION METRIC TONS OF CO_2E)

	2022	2031		
	Current	High Electrification *with Fuel Backup*	High Electrification *with Best-in-Class Technologies*	High Electrification *with Legacy Technologies*
Natural Gas	4.83	3.35	3.28	3.28
Liquid Fuels	1.99	1.44	1.43	1.43
Total Emissions	6.82	4.80	4.71	4.71
% Change	**–**	**–29.6%**	**–30.9%**	**–30.9%**

Sources and Notes: Emissions are estimated based on projected 2022 and 2031 consumption of each type of fossil fuel and the GHG emission rates of each fuel.

C. Electricity Demand

The study projects growth in seasonal and peak electricity loads through modeling of hourly load for each in-scope electric utility through 2031. The load forecasts submitted by each utility as part of the 2022–2031 Ten Year Plan (TYP) serve as the starting point for these projections. The utility load forecasts capture load growth associated with non-electrification related factors, such as customer growth and economic growth. Some utilities also account for the impacts of behind the meter (BTM) solar adoption and transportation electrification in their TYP load forecast. In order to align the assumptions of each utility's load forecast in this study's Reference Case, two adjustments were made to utility TYP load forecasts:

- **BTM Solar Adjustment:** Several utilities did not account for BTM solar at all in their load forecasts. To align assumptions, an adjustment is made to each utility's TYP load forecast so that the Reference Case reflects the level of solar adoption projected by the RPS Study. For all utilities except BGE this adjustment reduces projected load growth relative to the TYP. BGE already includes significant solar adoption impacts in its load forecast, so this adjustment is negligible for BGE's Reference Case.
- **Electric Vehicle Adjustment:** Some utilities did not account for electric vehicles at all in their forecasts and others assume significant adoption. To align assumptions, the electric vehicle component of each utility's TYP load forecast is adjusted so that the Reference Case reflects the level of sales growth projected by the Energy Information Administration.

TABLE 8: COMPARISON OF THIS STUDY'S REFERENCE CASE TO UTILITY TEN-YEAR PLANS (2022-2031)

	Annual Average Sales Growth Rate	Annual Average Peak Load Growth Rate
Ten Year Plan	0.10%	0.25%
Reference Case	−0.10%	−0.02%

Sources and Notes: This table shows the aggregate Maryland growth rates based on the weighted average of in-scope utilities. A utility-specific comparison is provided in the Technical Appendix.

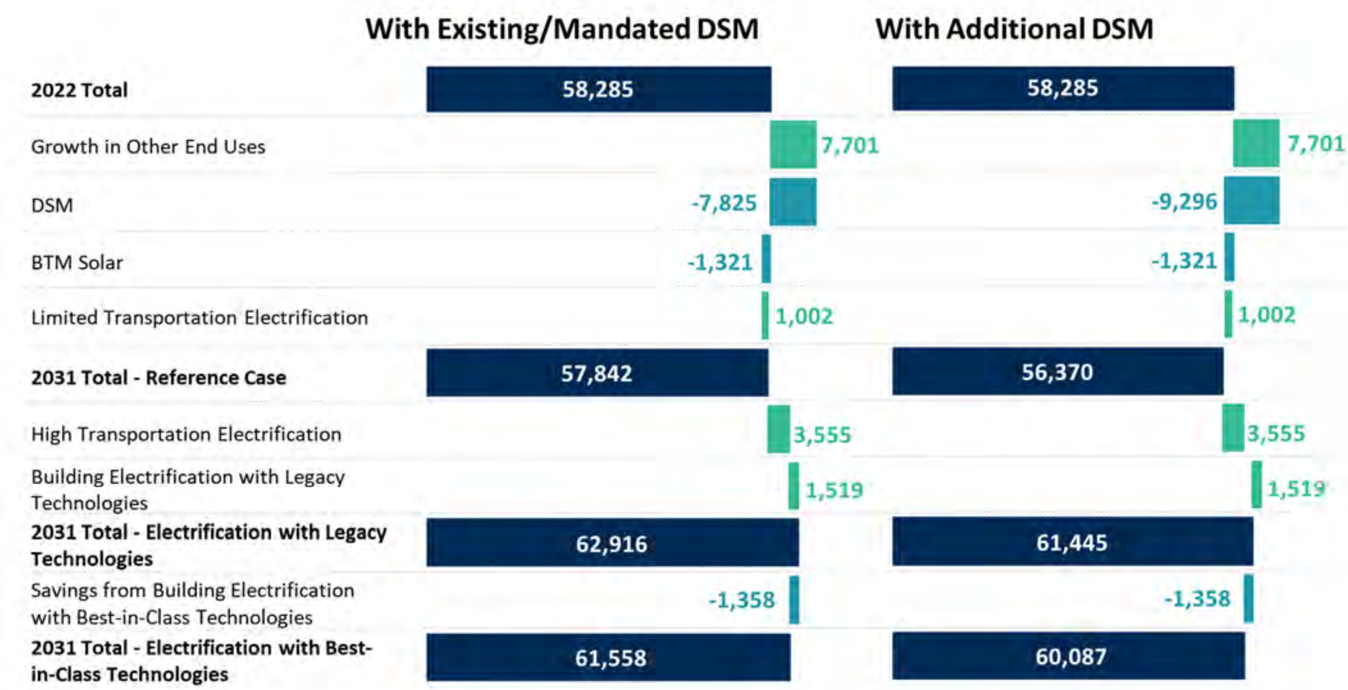
Electrification can have differing impacts on annual electricity sales and on peak load. Both metrics are important for planning purposes. Annual electricity sales are used as the basis for setting customer rates, and sufficient energy must be procured to meet customer demands. Higher electricity sales can drive electricity rates down, as costs are spread over a greater base of sales. Peak electricity loads drive grid investment, as each component of the distribution system must be sized to ensure reliability at peak load conditions. Higher peak loads can necessitate grid upgrades if existing parts of the grid do not have sufficient capacity, and associated costs would drive electricity rates up. This study quantifies the impacts of electrification on both sales and peak load, both at the system level.

1. Impact on Annual Electricity Sales

The Reference Case shows that with limited transportation electrification and no building electrification, the aggregate electric sales in Maryland would be flat (growth rate of −0.10% per year). As shown in Figure 6, flat electricity sales in the Reference Case are the result of growth being offset by mandated DSM programs and BTM solar adoption. Under the High Electrification with Fuel Backup and High Electrification with Legacy Technologies scenarios, sales would grow at 0.9% per year through 2031. The sales growth in these two scenarios is similar because the only difference between them is the use of backup fossil fuel equipment in a few hours of the year. Though this has a significant impact on peak load, it has a negligible impact on total electricity sales. In the Electrification with Best-in-Class Technologies scenario, the adoption of more efficient cold-climate heat pumps reduces the energy consumption for space and water heat, resulting in a slightly lower sales growth rate of 0.6% per year.

Expansion of DSM programs would mitigate some of the sales growth shown in the Existing/Mandated DSM Case. Figure 6 shows that the modeled additional DSM measures would result in annual energy savings of an additional 1,471 GWh by 2031. This would reduce the projected range of sales growth in the High Electrification Scenarios to 0.3-0.6% per year.

FIGURE 6: PROJECTED CHANGES IN MARYLAND ANNUAL ELECTRICITY SALES BETWEEN 2022 AND 2031

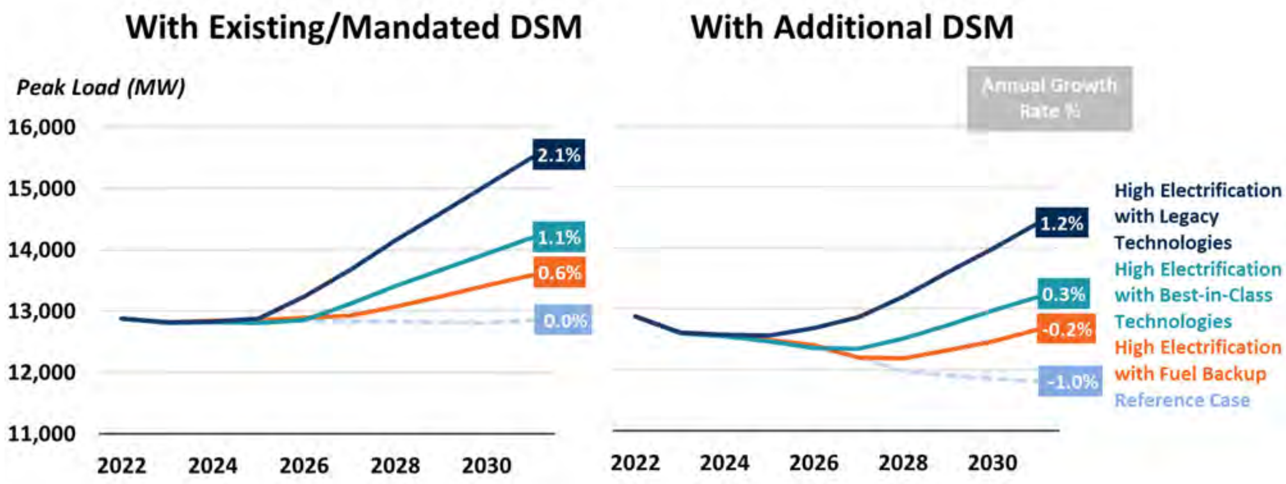


Sources and Notes: 2022 and 2031 Reference Case Sales Growth reflects utility load forecasts submitted as part of the 2022–2031 Ten Year Plan, with minor adjustments. The 2031 sales projection for the Electrification with Fuel Backup Scenario is the same as the Electrification with Legacy Technologies Scenario. DSM impacts are based on utility filings in the 2024–2026 EmPOWER program cycle. BTM solar, transportation, and building electrification impacts are based on Brattle modeling.

2. Impacts on Peak Load

In the Reference Case, which has limited transportation electrification and no building electrification, the aggregate Maryland system would remain summer-peaking, with negligible growth (−0.02% per year) through 2031. Under the High Electrification scenarios, the Maryland system would shift from summer-peaking to winter-peaking around 2026–2027, and load growth through 2031 would range from 0.6% to 2.1% per year with Existing/Mandated DSM programs, as shown in Figure 7.

FIGURE 7: PROJECTED AGGREGATE MARYLAND SYSTEM PEAK LOAD IN ELECTRIFICATION SCENARIOS



Sources and Notes: Reference Case reflects utility load forecasts submitted as part of the 2022–2031 Ten Year Plan, with minor adjustments. The Electrification Scenarios are projections based on Brattle modeling of the impacts of transportation and building electrification. Modeled additional DSM programs, which consist of cost-effective energy efficiency measures and a portfolio of load flexibility programs, would result in significant load mitigation relative to a case where only existing and mandated programs are deployed.

Peak loads in all three High Electrification scenarios occur around the coldest times of the year and are driven by electric heating loads. The Electrification with Legacy Technologies Scenario has the highest load growth of 2.1% per year. Peak loads in this scenario are driven by the use of relatively inefficient resistive heating that is assumed to supplement heat pumps when temperatures are below 22 F. The Electrification with Best-in-Class Technologies Scenario has significantly lower load growth of 1.1% per year. In this scenario, customer adoption of ccASHPs and GSHPs, both of which can be configured to operate without resistive backup, results in lower heating loads in the coldest hours of the year compared to legacy heat pumps. The Electrification with Fuel Backup Scenario results in the lowest load growth of 0.6% per year, as customers with existing fossil fuel heating are assumed to maintain their equipment and operate it during the coldest hours of the year when temperatures are below 20 F. This mitigates the highest potential electric heating peak loads, and shifts the peak load to less severe winter days.

Expansion of DSM programs would mitigate some of the peak load growth shown in the Existing/Mandated DSM Case. With Additional DSM, Figure 7 shows that in the High Electrification Scenarios, load growth through 2031 would range from −0.2% to 1.2%, which is significantly lower than the 0.6–2.1% growth rate projected with only existing/mandated DSM programs.

The portfolio of additional energy efficiency measures reduces load at various times of the day from various end uses, and has a small impact in the morning hours when the winter peak occurs. Load flexibility programs are more effective at mitigating peak loads by flattening the load shape relative to unmanaged load. This is achieved through various means, including preheating using smart thermostats, deferring water heating, and discharging behind-the-meter batteries.

As the timing of peak load shifts to mornings of the coldest days in winter, factors other than electric heating have less influence on the peak. BTM solar, which generates more energy in the summer and at mid-day, provides negligible load reduction during winter mornings. Electric vehicles, which tend to charge in the evenings and at night, do not significantly add to morning loads.

D. Utility-Specific Differences

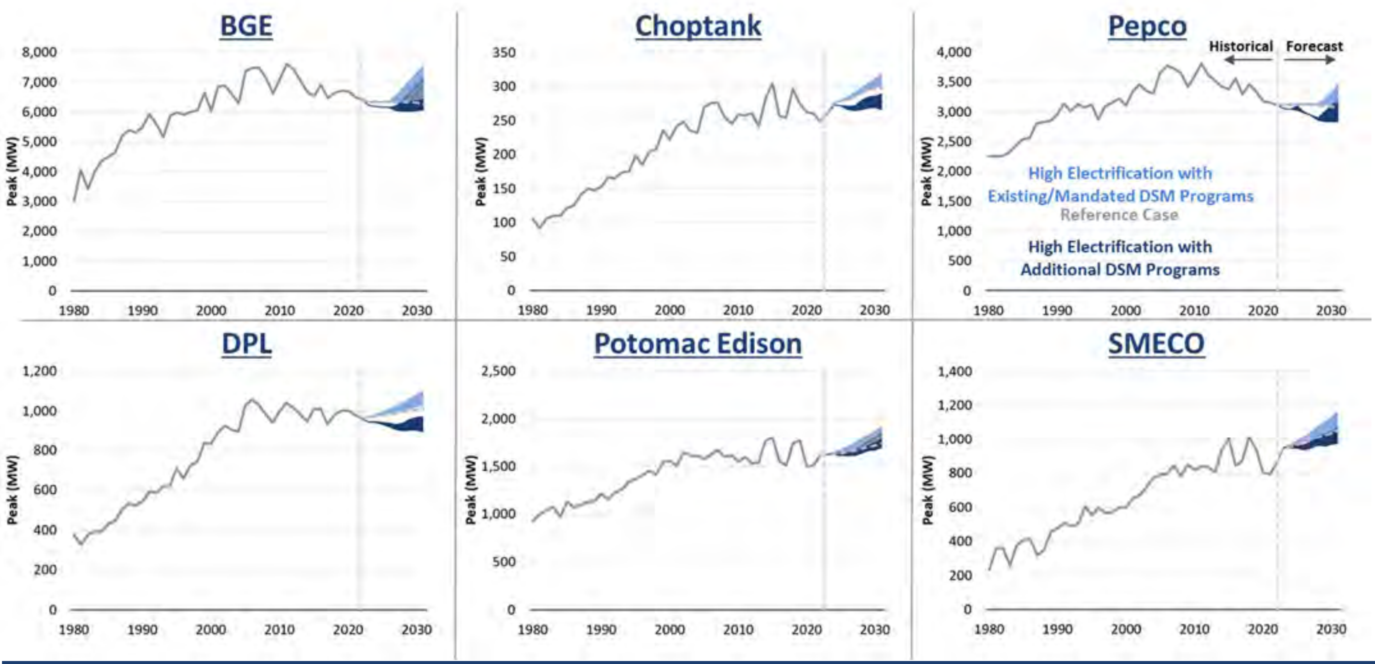
Each utility system and service territory may have unique characteristics in terms of its size, customer types, customer preferences, weather, regional economic growth, customer programs, and planning standards. While there are many factors that differ between the six in-scope electric utilities, two particularly important factors cause meaningful divergence in results.

Reference Case Forecast: The Reference Case forecasts indicate how much load growth each utility can expect with limited transportation electrification and no building electrification. There is significant divergence of Reference Case load forecasts between utilities. BGE and Pepco have load declining at rates of −0.27% and −0.16% per year respectively through 2031. On the other hand, Choptank, DPL, Potomac Edison, and SMECO have load growth of 0.56–2.30% per year through 2031. It follows that the utilities that already expect higher load growth in the Reference Case are also projected to have higher load growth in the High Electrification Scenarios.

Current Penetration of Electric Heating: The Maryland system as a whole peaks in the summer because the two largest utilities, BGE and Pepco, are summer-peaking. BGE and Pepco are summer-peaking because there is significant penetration of the natural gas delivery systems in their service territories, and fewer customers currently use electricity for heating. This implies the BGE and Pepco systems, currently sized for higher summer peaks, have some headroom for winter peak load growth before electric heating starts driving annual peaks. In contrast, DPL, Potomac Edison, and SMECO have more limited overlap with gas delivery service territories, and many more of their customers already use electricity for heating. Therefore, they are currently winter-peaking systems.

Figure 8 presents historical and projected in-scope utility system peak loads through 2031.

FIGURE 8: HISTORICAL AND PROJECTED UTILITY SYSTEM PEAK LOADS



	Reference	Fuel Backup		High Electrification with *Best-in-Class Technologies*		*Legacy Technologies*	
		Exst/Mandate DSM	Add. DSM	Exst/Mandate DSM	Add. DSM	Exst/Mandate DSM	Add. DSM
BGE	-0.3%	0.1%	-0.6%	0.8%	0.2%	1.8%	1.2%
Pepco	-0.2%	0.2%	-1.1%	0.2%	-0.6%	1.2%	0.4%
Potomac Edison	0.8%	1.2%	0.7%	1.2%	0.6%	1.9%	1.5%
DPL	0.6%	0.8%	-0.8%	0.8%	-0.7%	1.5%	0.1%
SMECO	2.3%	2.6%	1.6%	2.4%	1.5%	3.5%	2.6%
Choptank	2.0%	2.3%	1.3%	2.2%	0.8%	2.8%	1.8%

Sources and Notes: "Exst/Mandate DSM" refers to the Existing/Mandated DSM Programs cases and "Add. DSM" refers to the Additional DSM Programs cases. Historical load is sourced from utility data if available or backcasted from PJM zonal data for the corresponding zone if utility data is unavailable. Projected load growth rates are based on utility load forecasts submitted for the 2022–2031 Ten Year Plan and Brattle modeling of the impacts of energy efficiency, behind-the-meter solar, load flexibility, transportation electrification, and building electrification.

Finally, historical load growth trends suggest that the implications of projected load growth may vary across utilities. BGE and Pepco experienced their highest historical peak loads in 2011 and then saw load decline significantly from 2011 to 2022. Their load declines were significant enough that their projected 2031 peak loads in the highest load case of this study (Electrification with Legacy Technologies) is lower than their peak loads were in 2011. BGE's and Pepco's load declines from 2011–2022 suggest that their distribution systems likely have headroom to support some load growth, *on average*. However, it is possible for load growth to be concentrated in specific areas and still necessitate grid upgrades. The other four utilities saw flat or less significant load declines in the 2010s. Therefore, their projected 2031 peak loads in some high electrification scenarios are higher than their historical highest peak loads.

TABLE 9: COMPARISON OF HIGHEST PROJECTED PEAK LOAD TO HIGHEST HISTORICAL PEAK LOAD (MW)

Utility	Highest Projected 2031 Peak Load with Electrification	Highest Historical Peak Load (1980 -2022)
BGE	7,561	7,608
Pepco	3,460	3,806
Potomac Edison	1,921	1,798
DPL	1,100	1,056
SMECO	1,162	1,011
Choptank	318	305

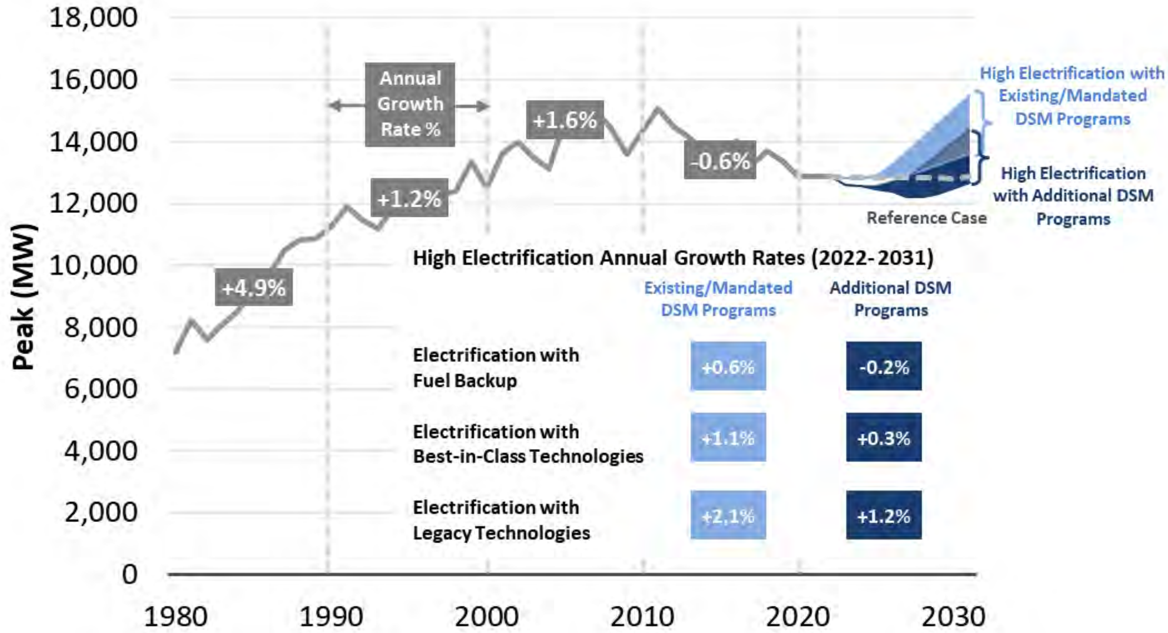
Sources and Notes: Historical load is sourced from utility data where available. Where utility data was unavailable, PJM historical growth rates for the corresponding zones were used to backcast 2022 peak load. Highest projected 2031 peak load with electrification refers to the Electrification with Legacy Technologies Scenario.

IV. Conclusion

The Maryland's Climate Pathway report demonstrates how Maryland can meet its ambitious climate goals of 60% reduction of greenhouse gas emissions by 2031 relative to 2006 levels, and attain a net-zero economy by 2045, all while realizing health and economic benefits for Marylanders, including improved air quality, new jobs, and household cost savings. This study modeled electrification scenarios that would result in direct building heating emissions reductions consistent with Maryland's Climate Pathway report. The results indicate that the aggregate Maryland electric systems would see growth rates in the range of 0.6–2.1% per year through 2031 with high electrification assuming utility energy efficiency plans consistent with the Climate Solutions Now Act and existing utility demand response plans. This increase in load growth is accompanied by a reduction in gas demand by about 20% by 2031 for high electrification scenarios. The Maryland electric distribution system, which is currently summer peaking, would switch to winter peaking around 2026–2027. Furthermore, additional energy efficiency and load flexibility measures could result in significant mitigation of load growth by 2031 to −0.2-1.2% compound annual growth per year.

Maryland electric utilities managed a peak growth rate of 4.9% per year in the 1980s, when there was rapid adoption of air conditioning. 1990–2010 saw more moderate load growth of 1.2–1.6%, and load declined in the 2010s during a period of large gains in energy efficiency. While the load growth caused by electrification would represent a paradigm shift in Maryland compared to the load declines of the past decade, even the highest projected growth rate of 2.1% per year is not extraordinary relative to growth served by the Maryland utilities in the past.

FIGURE 9: HISTORICAL AND PROJECTED ANNUAL LOAD GROWTH BY DECADE



Sources and Notes: Aggregate Maryland system load growth rates are based on the weighted average peak load growth of the in-scope utilities. Historical load growth rates are from utility provided forecasts when available or PJM zonal historic data for the corresponding zone. Projected load growth rates are based on utility load forecasts submitted for the 2022–2031 Ten Year Plan and Brattle modeling of the impacts of energy efficiency, behind-the-meter solar, load flexibility, transportation electrification, and building electrification.

This study projects utility system level average load growth rates through 2031. The modest system average load growth rates do not necessarily imply that distribution upgrades needed to support electrification will be insignificant. Distribution system planning is necessarily locational, and pockets of concentrated load growth may necessitate upgrades in some locations. A locational analysis of existing distribution system capacity and projected customer adoption of different technologies would be needed to identify specific areas that may require distribution upgrades. Nevertheless, the load declines of the past decade imply that on average, there is headroom on distribution systems to serve near-term load growth. In addition, the results show that deploying a portfolio of energy efficiency and load flexibility measures can lead to significant mitigation of load growth, even with high electrification. This combination of factors suggests that the transition to a highly electrified building sector in Maryland is manageable through 2031.

AUTHORS

Dr. Sanem Sergici |Principal | Boston

Sanem's practice focuses on regulatory and planning matters related to innovative rate design, electrification, distributed energy resources, and grid modernization. Sanem led numerous studies in these areas that were instrumental in regulatory approvals of grid modernization investments and integrated resource plans. She received her PhD in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her M.A. in Economics from Northeastern University, and B.S. in Economics from Middle East Technical University (METU), Ankara, Turkey.

sanem.sergici@brattle.com

Akhilesh Ramakrishnan |Managing Energy Associate | Chicago

Akhilesh specializes in policy analysis, regulatory economics, and strategic planning related to the demand side of the electricity sector. He has supported clients on a range of topics including economic analyses of electrification, rate design, resource planning, load flexibility, and value of solar. Prior to joining Brattle, he developed business strategy and policy for Exelon's electric and gas utility businesses. He received his M.S. in Mechanical Engineering from Columbia University, with a concentration in Energy Systems. He received his B.S. in Electrical Engineering from SRM University, India.

akhilesh.ramakrishnan@brattle.com

Kate Peters | Energy Research Associate | New York

Kate focuses her research on resource planning in decarbonized electric markets and economic analysis of distributed energy resources. She has supported utilities, renewable developers, research organizations, technology companies, and other private sector clients in a variety of energy regulatory and strategy engagements. Kate received her B.A. in Environmental Economics from Middlebury College.

kate.peters@brattle.com

Ryan Hledik| Principal | San Francisco

Ryan's consulting practice is focused on regulatory and planning matters related to emerging energy technologies and policies. His research on the "grid edge" has been cited in federal and state regulatory decisions, as well as by Forbes, National Geographic, The New York Times, Vox, and The Washington Post. Ryan received his M.S. in Management Science and Engineering from Stanford University, with a concentration in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics.

ryan.hledik@brattle.com

J. Michael Hagerty | Principal | Washington, DC

Michael specializes in the economic analysis of new technologies and resources across the power sector supply chain, including transportation and heating electrification, distributed solar resources, and transmission system upgrades. He assists electric utilities, renewable developers, transmission developers, and RTOs in understanding and preparing for a shifting market and policy landscape. Michael received his M.S. in Technology and Policy at Massachusetts Institute of Technology, and B.S. in Chemical Engineering from the University of Notre Dame.

michael.hagerty@brattle.com

Ethan Snyder and Julia Olszewski are Senior Energy Analysts, and Hazel Ethier is an Energy Analyst with The Brattle Group.

Technical Appendix

An Assessment of Electrification Impacts on the Maryland Electric Grid

TECHNICAL APPENDIX TO THE REPORT

Brattle

Table of Contents

1 – Study Scope and Scenario Design

Purpose of the Electrification Study

Senate Bill 528 ("SB528" or "The Climate Solutions Now Act of 2022" or CSNA) requires Maryland to reduce GHG emissions by 60% from 2006 levels by 2031 and achieve net-zero GHG emissions by 2045.

SB528 directed the PSC to conduct this study "*assessing the capacity of each company's gas and electric distribution systems to successfully serve customers under a managed transition to a highly electrified building sector.*"

In addition, SB528 set the following requirements for this study:

- *use a projection of average growth in system peak demand between 2021 and 2031 to assess the overall impact on each gas and electric distribution system*
- *compare future electric distribution system peak and energy demand load growth to historic rates*
- *consider the impacts of energy efficiency and conservation and electric load flexibility*
- *consider the capacity of the existing distribution systems and projected electric distribution system improvements and expansions to serve existing electric loads and projected electric load growth*
- *assess the effects of shifts in seasonal system gas and electric loads*

Our scenario design is focused on meeting the requirements for this study as stated in the CSNA

Climate Solutions Now Act of 2022, Md. S.B. 528 (2022)

What is In Scope

- For each in-scope utility system, in depth modeling of electric load, including hourly load impacts by end use and appliance type for transportation and buildings sectors through 2031
- Calibration of end uses in each sector to each utility's baseline, i.e., representing the mix of uses and equipment penetration that exists today based on the best available data
  - Distributed Energy Resources (DERs), energy efficiency, load flexibility, vehicles, heat pumps, hot water etc.
  - Rely on EmPOWER GHG abatement study, the PPRP 100% RPS Study and the MDE Pathway study
- Analysis of historical electric and/or gas demand trends for each in-scope utility
- Model six study scenarios and the implied incremental electrification additional to what is already included in utility baseline forecasts
- Track reductions in consumption of natural gas and other fossil fuels as electrification adoption increases
- Model the impacts of electric load mitigation measures (energy efficiency and load flexibility)
- Track the impacts (peak demand, annual energy, emissions) of increased electricity demand due to electrification and reductions in transportation and heating fuel demand on Maryland GHG emissions

1 The MDE Pathway study modeled Maryland's economy-wide decarbonization pathway to achieving the climate goals set by the CSNA (https://cgs.umd.edu/sites/default/files/2023-09/file_final_Maryland%27s Climate Pathway Report.pdf)

What is NOT in Scope

- Cost of each scenario and mitigation option
- Recommendations on specific utility distribution/delivery investment plans
- Questions and modeling efforts pertaining to the future of the gas delivery systems
- Regulatory and business models for electric and gas utilities
- Impact on electric and gas systems beyond 2031

Scenario Matrix

	Decarbonization Policy Goals not Pursued		Pursuit of Policy Goals through Hybrid Solutions		Pursuit of Policy Goals through Zero Direct Emissions Solutions	
	S.0	S.1	S.2A	S.2B	S.3A	S.3B
	Reference	Low Electrification	Mid Electrification	High Electrification with Fuel Backup	High Electrification with Best-in-Class Technologies	High Electrification with Legacy Technologies
Description	"Reference" for load impacts of other scenarios. Defined as the state of the world as implied by each utility's current load forecast.	Limited incremental electrification. Assumes policy goals are not met.	Mix of electrification and continued use of fuels.	High electrification with retention of existing fossil fuel equipment for backup.	Fossil fuel equipment is phased out through policy. Customers quickly adopt more advanced, efficient electric technologies.	Fossil fuel equipment is phased out through policy. Customers are slower to adopt more advanced, efficient electric technologies.
Buildings	**Fuel mix held flat** from 2022.	**Limited incremental electrification** (majority of existing gas and fossil customers do not adopt heat pumps by 2031).	**Fossil fuel equipment sales continue beyond 2030;** some customers switch to heat pumps.	By 2030, all new equipment sales are HPs. **Almost all existing customers retain their fossil fueled equipment as backup.**	By 2030, all new equipment sales are HPs[1]. **Most HPs are highly efficient ccASHPs.**	By 2030, all new equipment sales are HPs[1]. **Most HPs are less efficient ASHP+resistance backup.**
DERs	Distributed Energy Resources (DER) growth in line with RPS mandate.					
Transportation	Based on EIA projections.	3-year delay relative to ACC II and ACT.	Achievement of Advanced Clean Cars II (ACC II) and Advanced Clean Trucks (ACT) regulations.			
Demand Side Management (DSM)	For each scenario, we run two DSM cases with a range of Energy Efficiency (EE) and Load Flexibility programs: **1) Existing/Mandated DSM Programs Only** **2) Additional DSM Programs (i.e., new programs and growth of existing programs)**					

1 With some exceptions for the hardest-to-electrify cases (we assume at least 5% of sales will be exempt from the policy and remain as fossil fuel equipment sales)
ccASHP = cold climate air-source heat pump, ASHP = air-source heat pump, HP = heat pump

Goals and Design of Adoption Curves for Each Scenario

For each scenario, we model the evolution of heating and transportation equipment penetration in MD based on:

- The best available data on existing equipment penetration as the starting point
- Annual sales adoption curves for each equipment type through the end of the study period or beyond
- Typical pace of equipment stock turnover; we do not model accelerated replacements

What the adoption curves are:

- The adoption curves are formulated as S-shaped curves representing the share of annual new equipment sales for each modeled equipment type
- They are designed to enable us to study plausible future states of the world that fulfill the study's goal of evaluating the grid impacts of a "highly electrified building sector" in the context of MD's 2031 and 2045 climate goals
- They are informed (qualitatively) by the relative economics and policies related to different fuels and equipment types. E.g., ground source heat pump adoption may be low due to the high upfront cost; IRA incentives may accelerate heat pump adoption

What the adoption curves are not:

- They are not forecasts; they are "what-if" scenarios
- **They are not an endorsement of the technical feasibility or cost-effectiveness of a certain technology/solution**

Benchmarking to the 60x31 Decarbonization Goal

While the scope of this study is focused on quantifying the electric load impacts of high electrification of the building sector, it was important to benchmark resulting emission reductions to Maryland's decarbonization goals

- This benchmarking is necessarily imperfect due to differing studies, models, and data sources and the fact that the state's goals apply to the entire economy, not specific sectors such as buildings
- This study quantifies the reduction in fossil fuel consumption and associated direct emissions resulting from the electrification of residential and commercial space and water heating, but not the electric grid emissions impacts
- This study is not an economy-wide decarbonization study, and therefore does not model changes to components of the Maryland economy outside of transportation and buildings
- To benchmark this study's building electrification scenarios to the State's decarbonization goals, we calibrate emission reductions in the modeled sector of interest (building heating) to the emission reductions in MDE's economy-wide Climate Pathways Scenario for those particular end uses
- All three high electrification scenarios (S.3A, S.3B, S.2B) result in direct building heating emissions reductions consistent with MDE's Climate Pathways modeling, implying the 60x31 economy-wide goal can be met if other sectors also decarbonize according to MDE's Climate Pathways modeling. Two of these scenarios (S.3A, S.3B) pursue zero direct emissions solutions while S.2B pursues hybrid solutions with customers maintaining their fossil equipment as backup
- Other scenarios (S.0, S.1, S.2A) result in less direct building heating emissions reductions than MDE's Climate Pathways modeling, implying that unless other sectors of the economy decarbonize faster than MDE's modeled pathway, the 60x31 economy-wide goal will not be met

2 – Load Modeling Methodology and Assumptions

Goals of the Modeling Approach

- Incorporate the load impacts of sectors/technologies relevant to this study (EE, DERs, electrification, load flexibility)
- Account for future changes in load not modeled in this study
- Avoid double counting any end uses that may be modeled in both this study and the utility load forecasts
- Maintain consistency across utilities and with other state studies to the extent possible

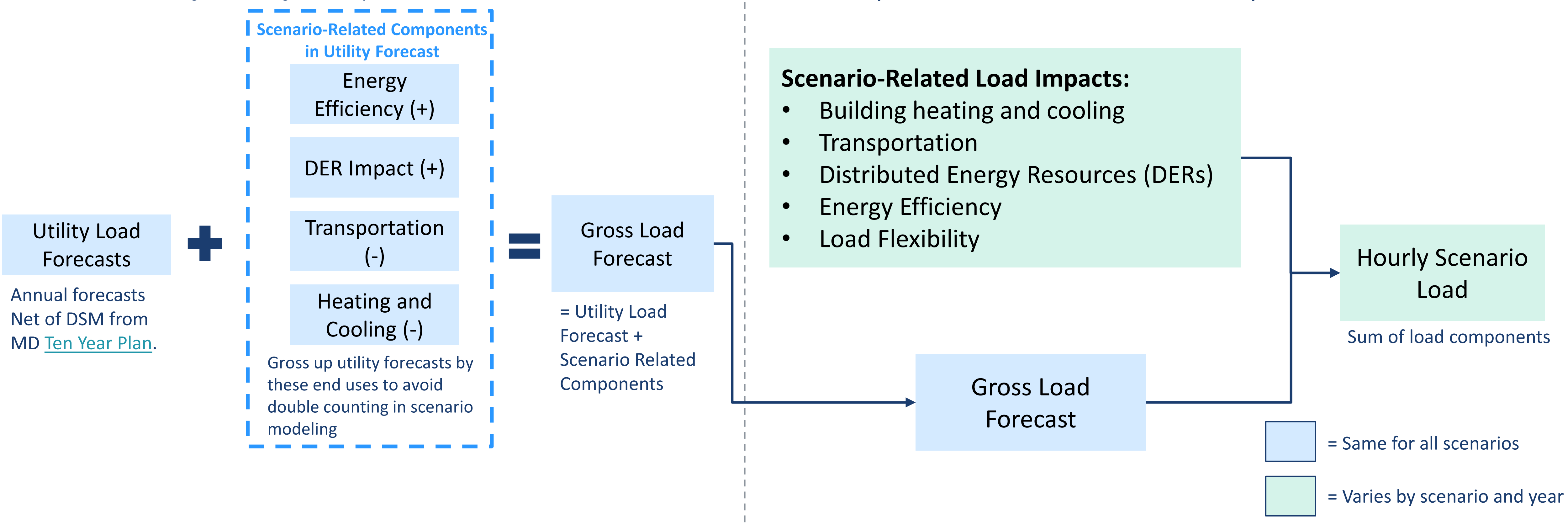
Approach to Scenario Load Modeling (I)

1 Disaggregate Utility Load Forecasts

Isolate end uses that will be modeled in this study (EE, DERs, heating, cooling, transportation)

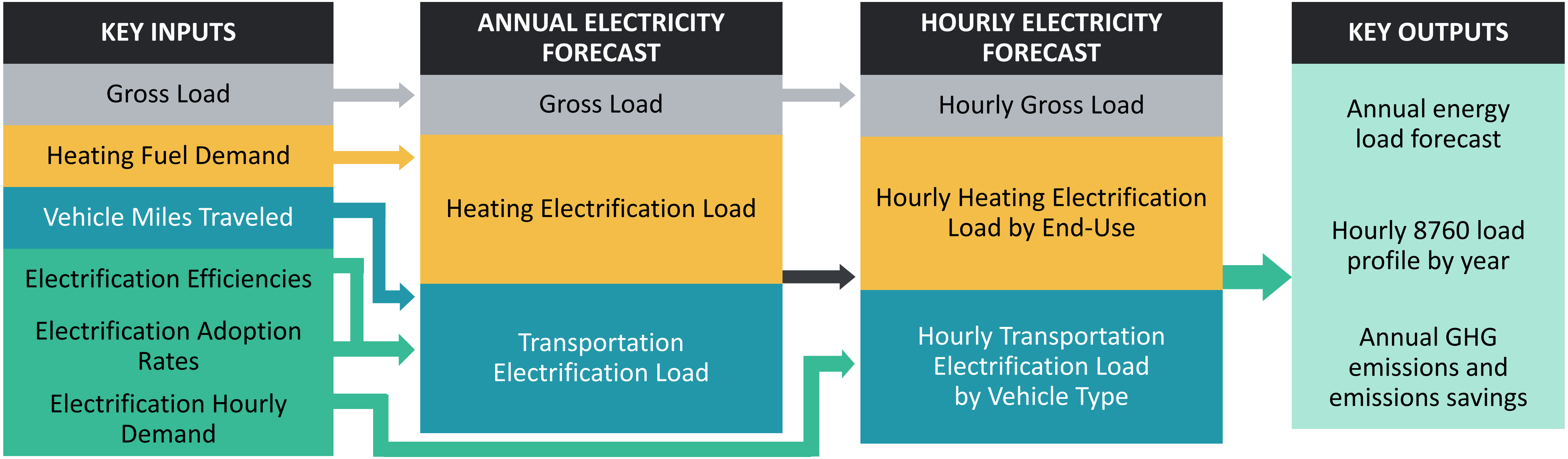
2 Model Electricity Demand in Each Scenario

Model scenario-based electrification for building and transportation sectors to assess load impacts



Approach to Scenario Load Modeling (II)

We rely on Brattle's Decarbonization, Electrification, & Economic Planning ("DEEP") Model to conduct the analyses of electric and gas load impacts of the six study scenarios



2019 Weather Year

The hourly load shape and temperature-related modeling use historical 2019 data

- 2019 was a non-extreme weather year that was close to the historical 30-year average high, low, and average temperatures
- Hourly load is built up from the 2019 actual hour load shape; the net load shape changes over time as projected electrification, DER, and load flexibility impacts take effect
- We use temperature data from a weather station in each utility region to capture regional differences

Baltimore Temperature Stats (1993-2022)

Metric	Degrees F
50/50 Low	8
90/10 Low	1
Lowest Low (ocurred in 1994)	-5
2019 Low Temp (Used in Study)	6

Baltimore Temperature (1993-2022)

	High Temperature	Low Temperature	Average Temperature
1993	100	9	55
1994	101	-5	56
1995	102	5	57
1996	94	-1	54
1997	101	1	55
1998	99	9	57
1999	102	7	56
2000	95	7	54
2001	98	14	56
2002	100	6	56
2003	93	5	54
2004	92	6	55
2005	96	9	56
2006	100	12	57
2007	102	8	56
2008	96	8	56
2009	94	2	55
2010	105	8	57
2011	106	8	58
2012	104	13	59
2013	97	11	56
2014	96	3	54
2015	97	1	56
2016	100	8	57
2017	98	8	57
2018	99	1	57
2019	**100**	**6**	**58**
2020	100	19	59
2021	99	19	59
2022	99	6	58
Average (1993-2022)	**99**	**8**	**56**

1994 = lowest low

2019 = model year

Source: NOAA

3 – Building Sector Assumptions and Inputs

Modeled Building and Equipment Types

Sector	Modeled Building Types	Space Heating Equipment Types	Water Heating Equipment Types
Residential	Single Family	• Fuel Oil furnace/boiler • Gas furnace/boiler • Gas heat pump • Other Fuels (propane, wood, etc.) • Electric resistance • Cold Climate air-source heat pump (ASHP) • ASHP + Resistance Backup • ASHP + Existing Fuel as Backup • GSHP	• Propane • Fuel Oil • Avg. Efficiency Gas • Efficient Gas • Electric Resistance • Electric Heat Pump
	Multifamily[2]		
Non-Residential	Exempt Commercial[1]		
	Covered Commercial[2]		

1 "Exempt" category includes: all buildings under 25k sq. ft., buildings 25k-35k sq. ft. outside Montgomery county, and any building types exempt from the Building Energy Performance Standards (BEPS).
2 "Covered" category includes buildings over 25k sq. ft. in Montgomery county or over 35k in the rest of MD, except exempt building types. "Covered Commercial" includes some residential multifamily building types.

Detail on Modeled Electric Heating Equipment

Modeled Equipment Types	Description
Electric Resistance Heaters	Some customers are currently heated by 100% resistive heat. This equipment is significantly less efficient than heat pumps and significant load reductions can be achieved by replacing them with heat pumps.
Cold Climate Air Source Heat Pump (ccASHP)	Standalone cold climate heat pumps sized to meet customers' peak heating load. No backup resistive heat.
ASHP + Resistance Backup	Less efficient and smaller heat pump. Resistive heating supplements the heat pump at temperatures below 22F.
ASHP + Fuel Backup	Less efficient and smaller heat pump. Their existing fossil fuel equipment is maintained. The heat pump is assumed to supply 100% of the heat above 20F and the fossil equipment supplies 100% of the heat below 20F.
Ground Source Heat Pump (GSHP)	Standalone ground source heat pumps sized to meet customers' peak heating load.

Calibrating to Maryland's Existing Fuel Mix

The starting point for equipment penetration was based on the best available data from previous MD studies, with some adjustments to account for newer information.

- Current saturation of residential space and water heating equipment informed primarily by Verdant's September 2022 survey for the GHG potential study.
- Current saturation of commercial space and water heating equipment informed by EIA CBECS 2018
- The Heat Pump Subgroup conducted a survey of contractors about the mix of heat pump configurations they installed or serviced in the past 12 months in Maryland. We used the results to inform more granular assumptions on heat pump configurations:
  - **12%** of existing homes with heat pumps qualify as cold-climate ASHP
  - **69%** of homes with heat pumps operate with electric resistance backup
  - **10%** of homes with heat pumps operate with gas backup
  - **9%** of homes with heat pumps operate with fuel backup
- Though the contractor survey was limited to the residential sector, we assume the same mix of heat pump configurations for the commercial sector due to lack of other data sources
- Our adoption curves (for annual new sales) use the existing equipment saturation proportions as the starting point. E.g., since ~30% of homes currently use heat pumps, we assume 30% of 2023 new equipment sales are heat pumps (this is likely a conservative assumption as heat pump sales have been growing).

Existing Fuel Mix by Utility

Existing Fuel Mix (2022)

	BGE	Choptank	DPL	PEPCO	Potomac Edison	SMECO	BGE	Choptank	DPL	PEPCO	Potomac Edison	SMECO
	Residential Water Heating						**Commercial Water Heating**					
Electric Heat Pump	5%	6%	6%	4%	9%	15%	5%	8%	8%	5%	7%	7%
Electric Resistance	52%	71%	71%	43%	73%	63%	56%	91%	89%	58%	75%	72%
Fossil	43%	23%	23%	52%	18%	23%	39%	1%	3%	37%	18%	21%
	Residential Space Heating						**Commercial Space Heating**					
ccASHP	3%	5%	5%	2%	3%	5%	0%	0%	0%	0%	0%	0%
GSHP	2%	2%	2%	1%	3%	6%	1%	1%	1%	1%	1%	1%
ASHP + Resistance	16%	27%	27%	12%	20%	26%	9%	23%	23%	8%	17%	15%
ASHP + Fuel Hybrids	4%	7%	7%	4%	5%	7%	0%	0%	0%	0%	0%	0%
Electric Resistance	20%	25%	25%	17%	31%	26%	28%	75%	72%	27%	55%	55%
Fossil	54%	34%	34%	63%	38%	30%	62%	1%	5%	64%	27%	30%

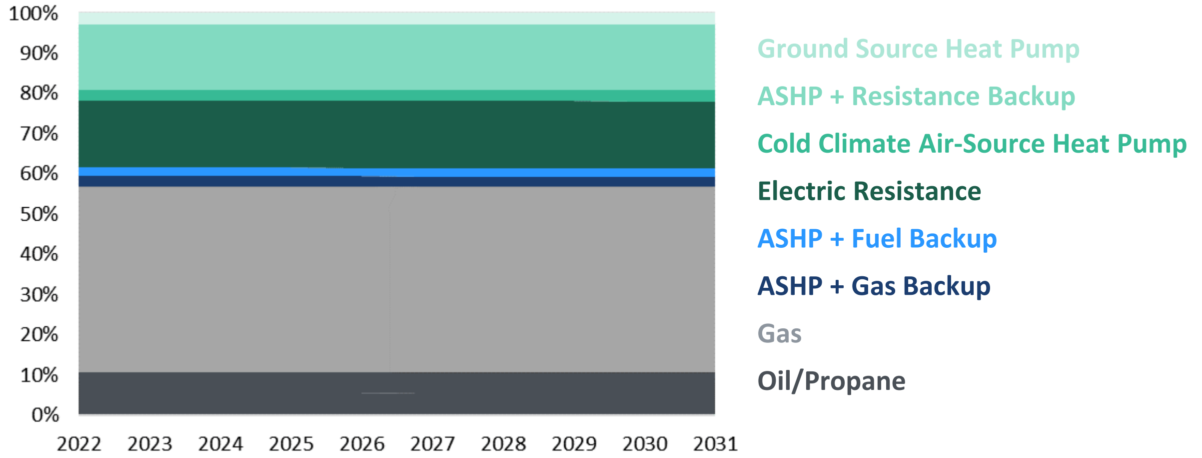
Note: Utility totals may not sum to 100% due to rounding. ccASHP = cold climate air source heat pump, ASHP = air source heat pump, GSHP = ground source heat pump
Data sources noted in previous slide.

Residential Space Heating Adoption Curves – All MD – S.0 and S.1

Adoption Curves (% of new sales)

Description

S.0: Reference

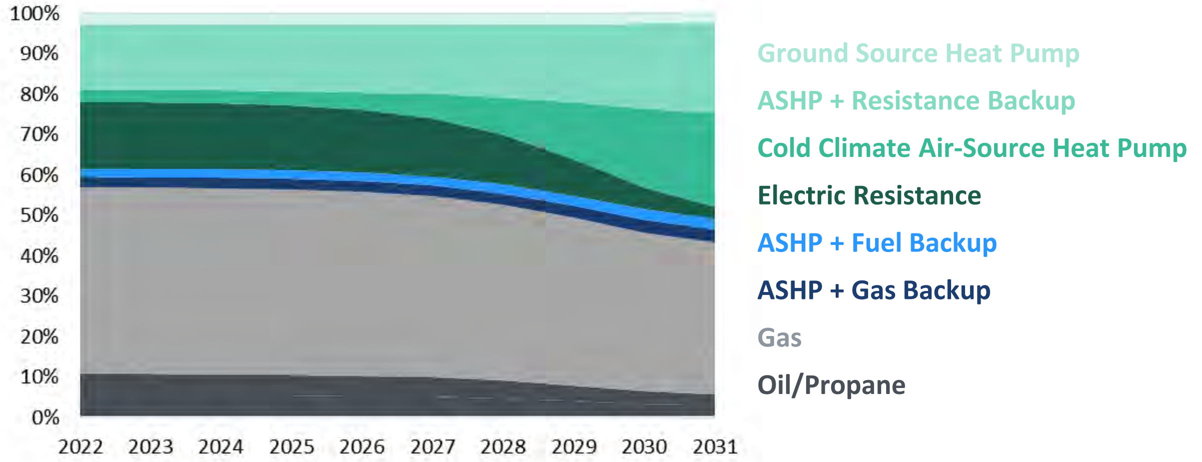


Assumes no fuel switching:

- At the end of equipment lifetimes stock is replaced by new equipment of the same type
- Aligned with EmPOWER GHG study BAU case

Leads to 2031 fuel mix the same as today's mix.

S.1: Low Electrification



Very slow change in fuel mix:

- Delivered fuel equipment sales fall by almost 50% by 2031
- Gas equipment sales fall by 20% by 2031
- Electric heating equipment sales are 48% ccASHP, 44% ASHP+resistance, 5% GSHP, and 3% Electric Resistance

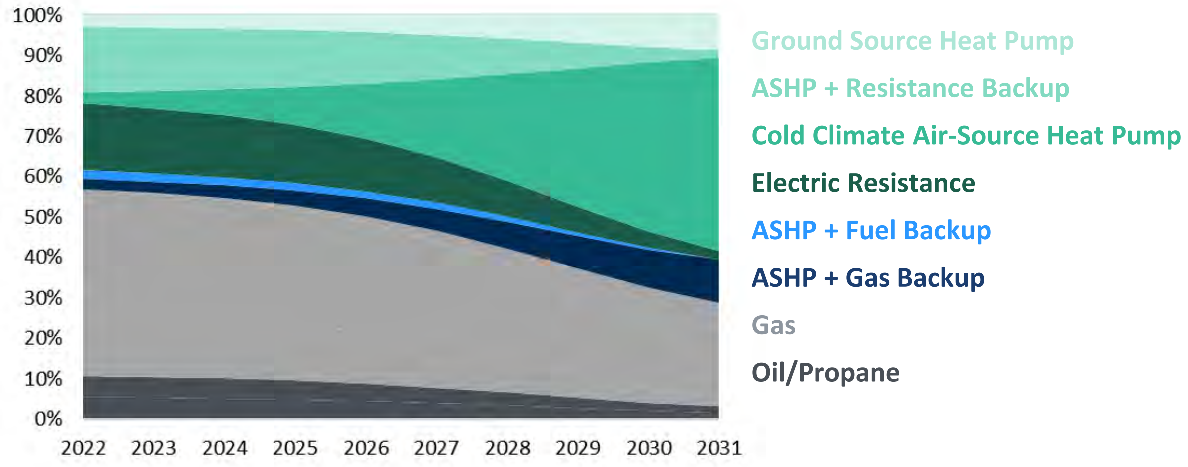
Leads to 2031 mix similar to today's mix.

Residential SH Adoption Curves – all MD – S.2

Adoption Curves (% of new sales)

Description

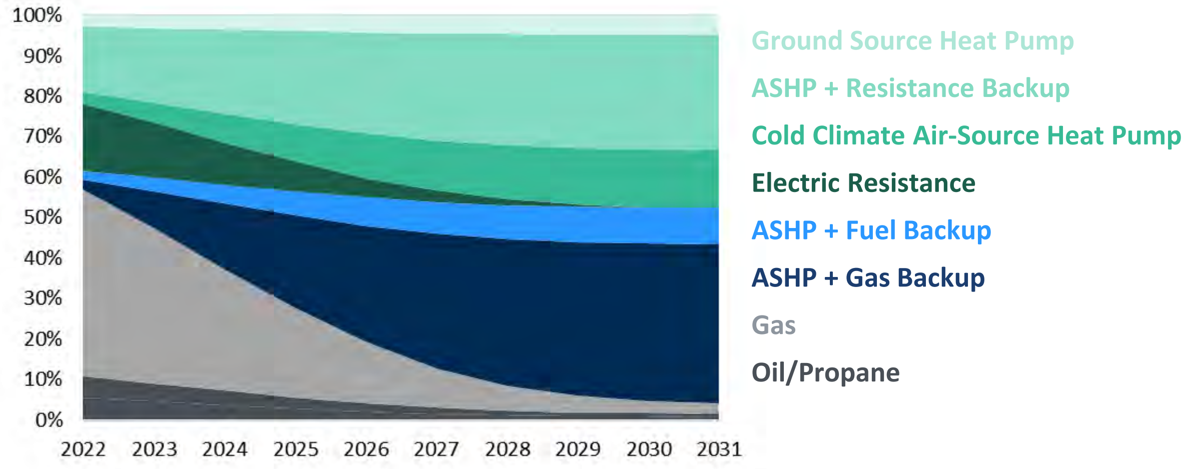
S.2A:
Mid
Electrification



Heat pumps sales grow but fuel equipment sales continue beyond 2031:

- Delivered fuel equipment sales fall 70% by 2031
- Gas equipment sales fall 40% by 2031
- Full electric heating equipment sales are 85% ccASHP, 15% GSHP

S.2B:
High
Electrification
with Fuel
Backup



Most new equipment sales are HPs by 2030*:

- At end of equipment life, 85% of existing fossil fuel customers add ASHPs and keep their fossil equipment (gas, oil, or propane) for backup
- Full electric heating equipment sales are 30% ccASHP, 60% ASHP+resistance, 10% GSHP

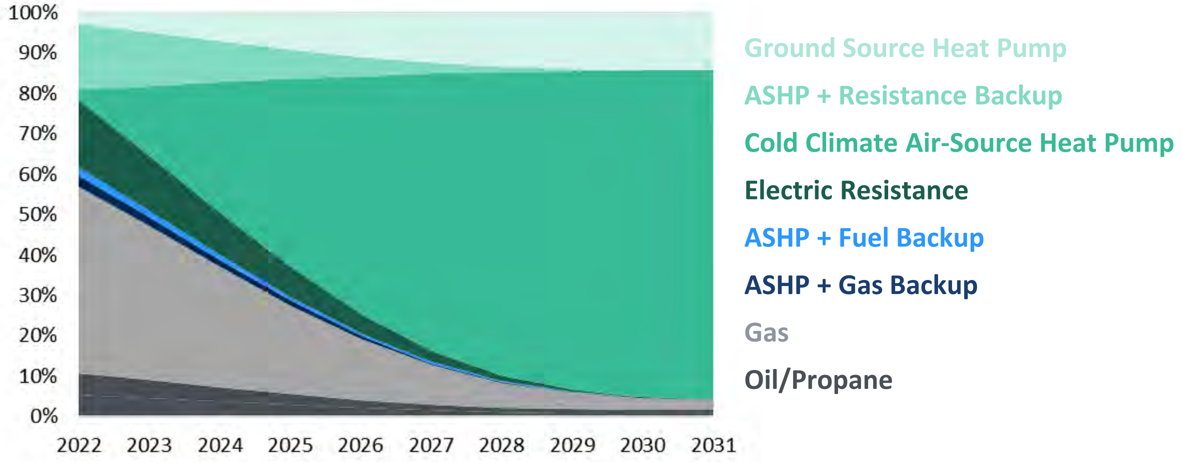
*Note: Delivered fuel and standalone gas equipment sales fall to almost zero (we assume a small amount because the regulation is likely to allow some exceptions)

Residential SH Adoption Curves – all MD – S.3

Adoption Curves (% of new sales)

Description

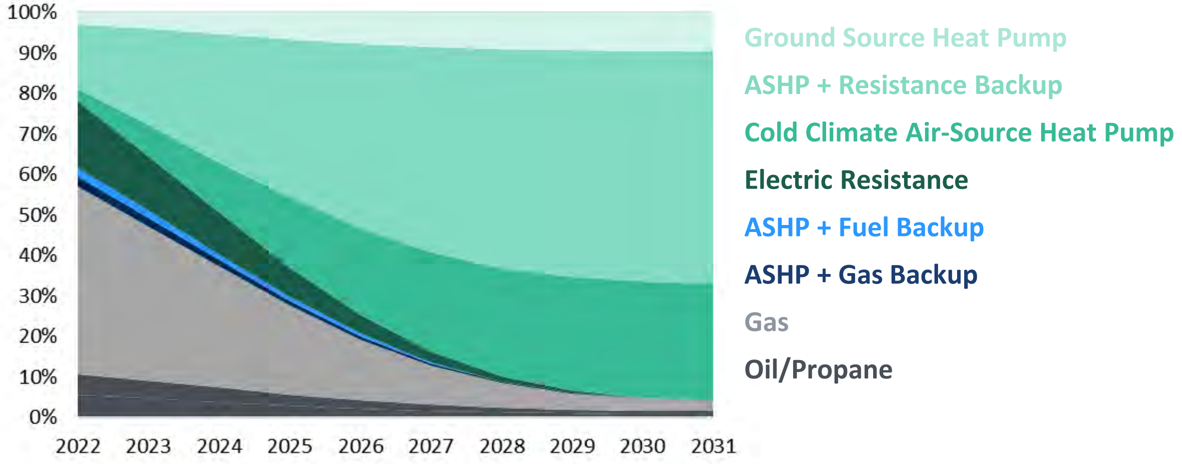
S.3A: High Electrification Best-in-Class Technologies



All fossil fuel equipment sales fall to zero by 2030:

- Fully electric sales are 85% ccASHP and 15% GSHP
- ASHP+resistance sales fall to zero because ccASHPs are more efficient and widely available (in this scenario per definition)
- Delivered fuel and standalone gas equipment sales fall to almost zero (we assume a small amount because the regulation is likely to allow some exceptions)

S.3B: High Electrification with Legacy Technologies



All fossil fuel equipment sales fall to zero by 2030:

- Fully electric sales are 30% ccASHP, 60% ASHP+resistance, 10% GSHP
- Delivered fuel and standalone gas equipment sales fall to almost zero (we assume a small amount because the regulation is likely to allow some exceptions)

Scenarios - Residential Space Heating Stock

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

Space Heating Equipment Penetration, *% of residential customers*

Fossil = gas, oil, propane equipment; ASHP = air source heat pumps; GSHP = ground source heat pumps; ccASHP = cold climate air source heat pumps
Water heating equipment penetrations are provided in the appendices.

Scenarios - Commercial Space Heating Stock

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

Space Heating Equipment Penetration, *% of heated floor area*

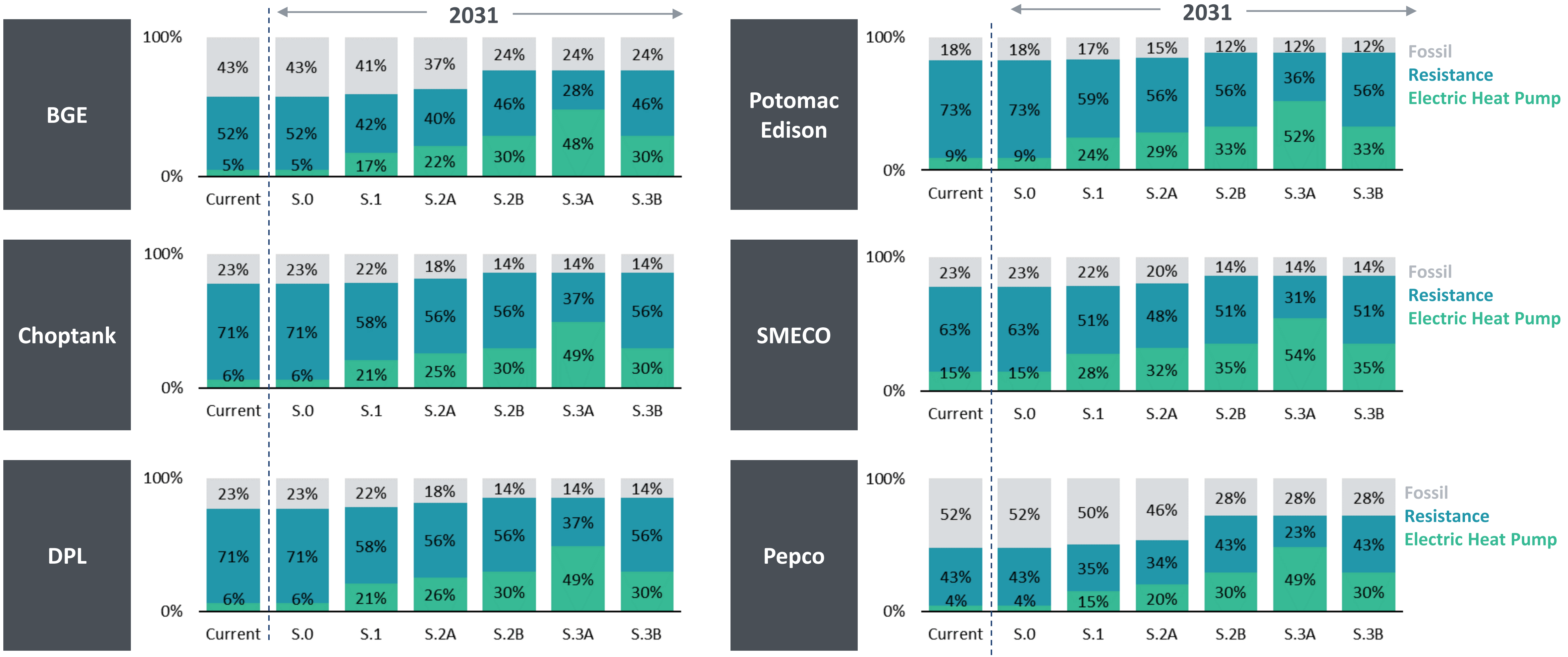
Fossil = gas, oil, propane equipment; ASHP = air source heat pumps; GSHP = ground source heat pumps; ccASHP = cold climate air source heat pumps
Water heating equipment penetrations are provided in the appendices.

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

BUILDING SECTOR ASSUMPTIONS AND INPUTS

Scenarios - Residential Water Heating

Water Heating Equipment Penetration, *% of residential customers*

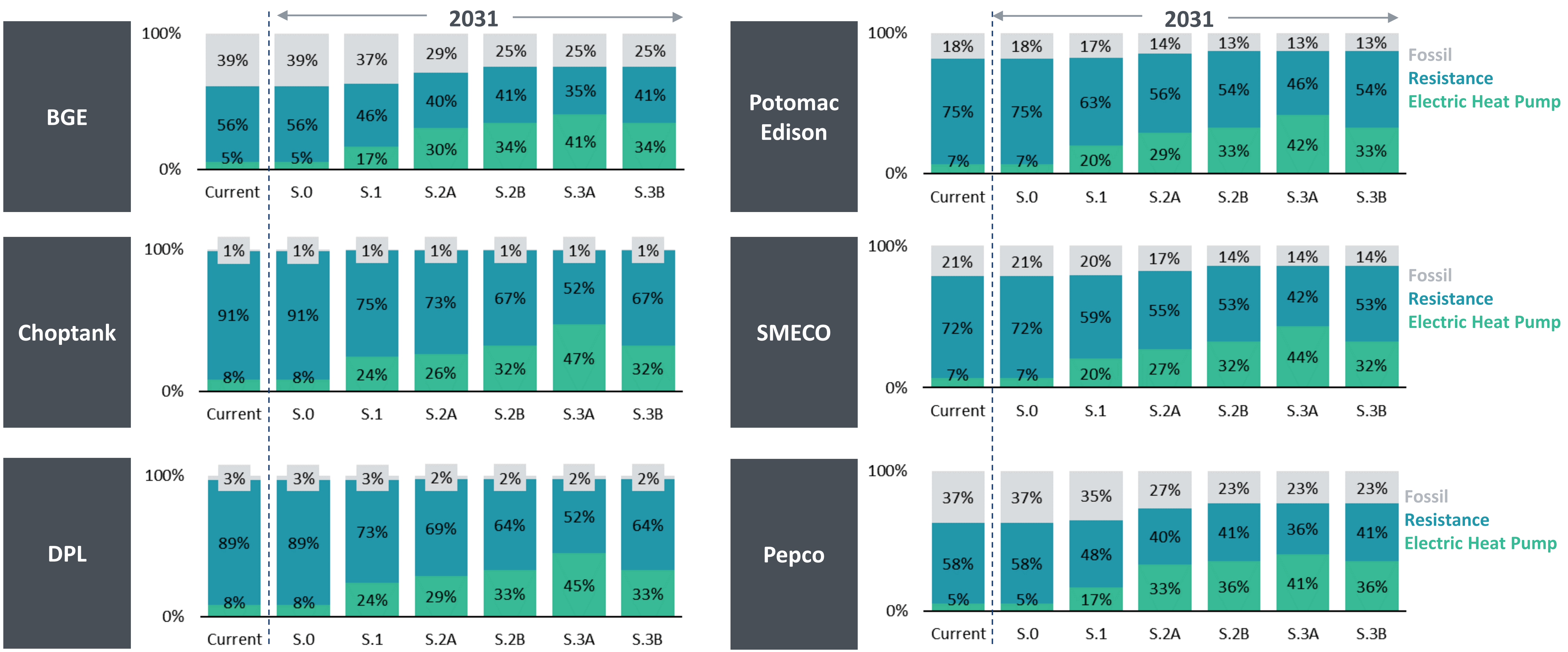


Fossil = gas and oil.

Scenarios - Commercial Water Heating

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

Water Heating Equipment Penetration, *% of floor area*



Fossil = gas and oil.

Utility Customer Forecasts

Utility-Level Customer Count and Square Footage Forecast

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2022- 2031 CAGR
Residential Single-Family Home Customer Count											
BGE	870,886	875,307	879,491	883,719	888,108	892,711	897,418	902,176	906,904	911,240	0.5%
DPL	112,398	112,775	113,209	113,627	114,036	114,446	114,857	115,270	115,684	116,101	0.4%
Pepco	374,346	377,753	381,060	384,385	387,664	390,971	394,306	397,671	401,063	404,485	0.9%
PE	191,453	194,068	196,766	199,382	201,961	204,500	206,967	209,387	211,773	214,126	1.3%
Chop	30,709	30,889	31,069	31,186	31,271	31,358	31,452	31,556	31,673	31,795	0.4%
SMECO	127,036	131,428	133,208	135,069	137,254	139,359	141,463	143,648	145,914	147,532	1.7%
Total	**1,706,829**	**1,722,219**	**1,734,803**	**1,747,367**	**1,760,293**	**1,773,344**	**1,786,463**	**1,799,708**	**1,813,011**	**1,825,279**	**0.7%**
Residential Multi-Family Home Customer Count											
BGE	329,406	331,078	332,660	334,259	335,919	337,661	339,441	341,241	343,029	344,669	0.5%
DPL	69,630	69,864	70,133	70,392	70,645	70,899	71,154	71,410	71,667	71,924	0.4%
Pepco	169,639	171,182	172,681	174,187	175,673	177,172	178,684	180,208	181,746	183,296	0.9%
PE	59,568	60,381	61,221	62,035	62,837	63,627	64,395	65,148	65,890	66,622	1.3%
Chop	19,024	19,135	19,247	19,319	19,373	19,427	19,485	19,549	19,621	19,697	0.4%
SMECO	29,937	30,972	31,392	31,831	32,346	32,841	33,337	33,852	34,386	34,768	1.7%
Total	**677,204**	**682,613**	**687,334**	**692,024**	**696,793**	**701,627**	**706,495**	**711,408**	**716,339**	**720,976**	**0.7%**
Commercial Covered Square Footage (Thousands)											
BGE	706,336	710,437	713,966	717,495	721,023	724,552	728,081	731,610	735,139	738,667	0.5%
DPL	57,405	57,680	57,958	58,217	58,467	58,720	58,973	59,228	59,482	59,739	0.4%
Pepco	322,740	325,566	327,714	329,869	331,811	333,760	335,721	337,695	339,676	341,676	0.6%
PE	92,812	96,860	96,860	96,860	96,860	96,860	96,860	96,860	96,860	96,860	0.5%
Chop	39,762	39,994	40,227	40,375	40,488	40,601	40,721	40,855	41,011	41,166	0.4%
SMECO	40,108	40,415	40,696	41,054	41,361	41,616	41,898	42,179	42,460	42,664	0.7%
Total	**1,259,163**	**1,270,951**	**1,277,421**	**1,283,869**	**1,290,011**	**1,296,109**	**1,302,253**	**1,308,426**	**1,314,627**	**1,320,773**	**0.5%**
Commercial Exempt Square Footage (Thousands)											
BGE	332,969	334,902	336,565	338,229	339,892	341,556	343,219	344,883	346,546	348,210	0.5%
DPL	70,620	70,958	71,301	71,619	71,927	72,238	72,549	72,862	73,176	73,492	0.4%
Pepco	122,154	123,224	124,037	124,853	125,588	126,325	127,068	127,815	128,565	129,322	0.6%
PE	78,331	81,748	81,748	81,748	81,748	81,748	81,748	81,748	81,748	81,748	0.5%
Chop	86,593	87,097	87,605	87,928	88,174	88,420	88,681	88,973	89,311	89,650	0.4%
SMECO	48,735	49,108	49,450	49,884	50,257	50,568	50,909	51,251	51,593	51,841	0.7%
Total	**739,403**	**747,037**	**750,705**	**754,261**	**757,586**	**760,855**	**764,175**	**767,533**	**770,939**	**774,262**	**0.5%**

Sources and notes: Utility provided customer forecasts, Ten Year Plan (November 2022), GHG EmPOWER study surveys, and CBECs 2018. "Covered" refers to buildings covered by the BEPS and Montgomery county regulations (large buildings); "Exempt" refers to buildings exempt from the regulations (smaller buildings).

Service Demand per Customer

Service demand per customer refers to the amount of usable energy required by customers for each end use (regardless of the fuel/equipment it comes from).

Building Service Demand (Annual MMBtu/residential customer or Btu/commercial sq ft)

	BGE	DPL	Choptank	Pepco	Potomac Edison	SMECO
Single Family Space Heat	52.1	62.3	62.3	52.7	49.2	51.7
Single Family Water Heat	8.2	8.9	8.9	7.8	8.8	8.8
Single Family Cooling	41.9	46.1	46.1	40.0	42.3	48.7
Multi Family Space Heat	13.1	12.9	12.9	23.0	18.8	18.2
Multi Family Water Heat	7.1	7.1	7.1	7.1	7.3	7.9
Multi Family Cooling	15.5	14.5	14.5	13.4	19.4	26.6
Covered Space Heat	31,052	31,428	29,835	33,396	30,991	28,454
Covered Water Heat	4,330	4,634	4,887	4,472	4,460	5,150
Covered Cooling	55,110	56,413	54,460	53,640	54,390	53,131
Exempt Space Heat	30,234	35,658	36,924	30,960	34,076	32,798
Exempt Water Heat	4,396	4,972	4,618	3,977	4,603	4,867
Exempt Cooling	52,427	53,458	52,032	51,805	52,011	52,205

Sourced from Verdant survey and utility customer data from EmPOWER GHG Potential Study. “Covered” refers to buildings covered by the BEPS and Montgomery county regulations (large buildings); “Exempt” refers to buildings exempt from the regulations (smaller buildings).

Equipment Efficiencies and Useful Lifetimes

Residential Sector Equipment Efficiencies

	2022 New Installs	2031 New Installs	2022-2031 CAGR	Equipment Lifetimes
Space Heating				
Fuel Oil	0.83	0.83	0.00%	20
Avg. Efficiency Gas	0.80	0.80	0.00%	20
Efficient Gas	0.95	0.95	0.00%	20
Gas Heat Pump	1.30	1.30	0.00%	20
Electric Resistance	0.98	0.98	0.00%	20
Cold Climate Air-Source Heat Pump (ASHP)	N/A	N/A	3.24%	20
ASHP + Resistance Backup	N/A	N/A	2.26%	20
ASHP + Gas Hybrid System	N/A	N/A	2.26%	20
ASHP Hybrid, Other Fuels	N/A	N/A	2.26%	20
Ground-Source Heat Pump	3.64	4.23	1.70%	20
Propane	0.83	0.83	0.00%	20
Cooling				
ASHP	4.48	4.75	0.64%	20
GSHP	5.07	5.07	0.00%	20
Central AC	4.13	4.25	0.30%	20
Water Heating				
Fuel Oil	0.64	0.64	0.00%	15
Avg. Efficiency Gas	0.61	0.61	0.00%	15
Efficient Gas	0.83	0.83	0.00%	15
Electric Resistance	0.92	0.92	0.00%	15
Electric Heat Pump	3.30	3.79	1.55%	15
Propane	0.64	0.64	0.00%	15

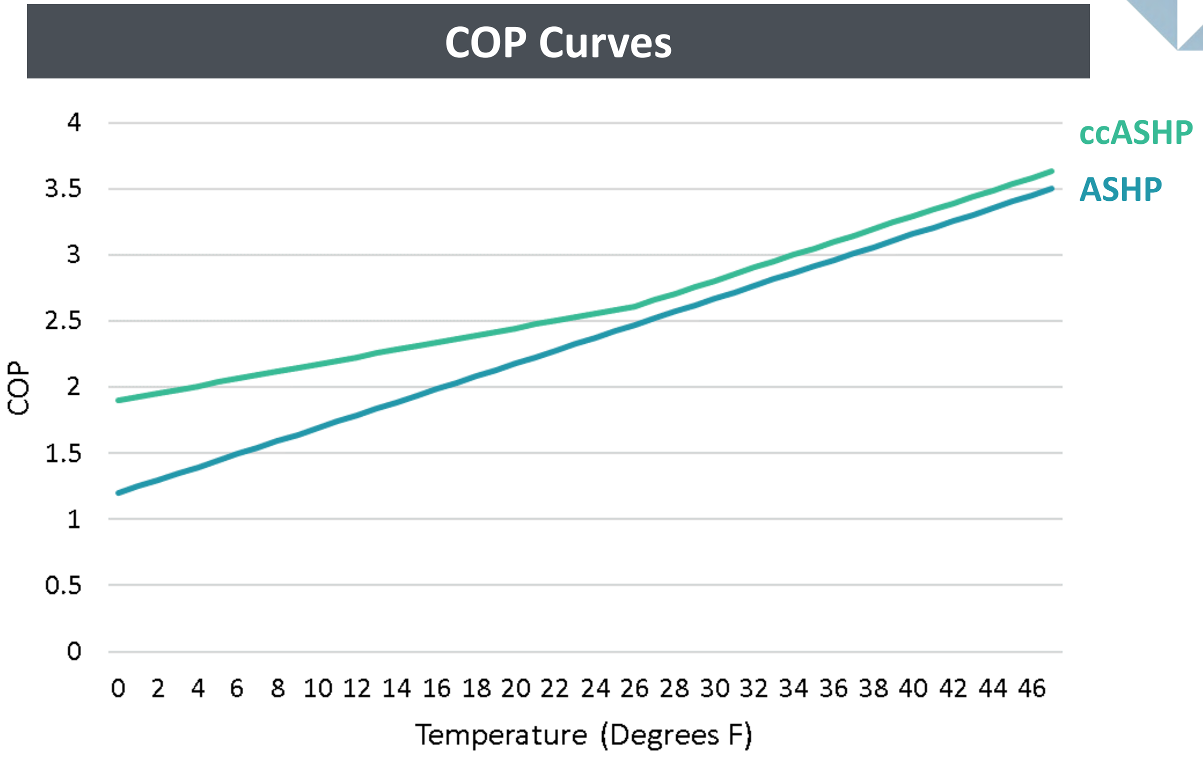
Commercial Sector Equipment Efficiencies

	2022 New Installs	2031 New Installs	2022-2031 CAGR	Equipment Lifetimes
Space Heating				
Fuel Oil	0.82	0.82	0.00%	16
Avg. Efficiency Gas	0.81	0.81	0.00%	16
Efficient Gas	0.95	0.95	0.00%	16
Gas Heat Pump	1.30	1.30	0.00%	16
Electric Resistance	0.98	0.98	0.00%	16
Cold Climate Air-Source Heat Pump (ASHP)	N/A	N/A	2.26%	16
ASHP + Resistance Backup	N/A	N/A	0.65%	16
ASHP + Gas Hybrid System	N/A	N/A	0.65%	16
ASHP Hybrid, Other Fuels	N/A	N/A	0.65%	16
Ground-Source Heat Pump	3.44	4.00	1.70%	16
Propane	0.82	0.82	0.00%	16
Cooling				
ASHP + Resistance Backup	4.10	4.10	0.00%	16
ASHP + Gas Hybrid System	3.55	3.55	0.00%	16
ASHP Hybrid, Other Fuels	4.19	4.23	0.10%	16
Ground-Source Heat Pump	4.98	4.98	0.00%	16
Water Heating				
Fuel Oil	0.80	0.80	0.00%	16
Avg. Efficiency Gas	0.80	0.80	0.00%	16
Efficient Gas	0.94	0.94	0.00%	16
Electric Resistance	0.98	0.98	0.00%	16
Electric Heat Pump	3.90	4.19	0.80%	16
Propane	0.80	0.80	0.00%	16

Sources and notes: For heat pump technologies, annual COP is a function of hourly COP that is modeled based on hourly temperature. Efficiency improves each year with the CAGR.
EIA - Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case and NREL EFS

Heating Load Modeling: Hourly Heat Pump COPs

- **ASHP:** Coefficient of Performance (COP) modeled as a function of hourly temperature based on input COP vs. temperature curves. See chart for COP assumptions for standard ASHP and cold-climate ASHP (ccASHP)
- **ASHP with fossil backup:** ASHP serves 100% of heating load in hours above cut-in temperature (20 degrees F). All heating demand below cut-in temperature is served exclusively by fossil source. Fossil backup COP does not vary with temperature
- **ASHP with resistance backup:** Resistive heat supplements the ASHP below cut-in temperature (22 degrees F), at COP of 1. ASHP continues to operate.
- **Ground Source Heat Pump:** COP does not vary with hourly temperature



Sources for COP and cut-in temperature: Gibb, *et. al*, Coming in from the cold: Heat Pump efficiency at low temperatures; Goodman GSH13 Split System Heat Pump Product Specifications. ASHP curve based on NEEP Standards. Chart shows Brattle interpolation of the point ratings provided in the sources.

Electric Load Impacts of Fuel Switching

As customers switch fuel types, their electric peak impact varies based on a few key factors:

- **Current fuel**: Customers that currently heat with fossil fuels add electric load after fuel-switching. Customers that already have electric heat reduce load when adopting heat pumps due to the higher efficiency.
- **Customer size** Larger customers have higher heating demands. Data shows that oil and natural gas customers, on average, have much larger homes than electric resistance heating customers.
- **Adopted electric equipment** impacts are highest for fuel-switching to electric resistance and lowest for customers that switch to GSHP (this study does not model any switching to resistance).

Impact of Fuel Switching on Electric Load (non-coincident peak)

Varies by current fuel and new equipment type

Current Fuel Type	Customer Size	Per-Customer Electrification Peak Impact (kW)				
		Electric Resistance	ASHP + Resistance Backup	Cold-Climate Heat Pump (ccASHP)	ASHP + Fossil Backup	Ground-Source Heat Pump (GSHP)
Liquid Fuels	Some of the largest customers currently heat their homes with liquid fuels. When these customers electrify, they have the largest electric impacts. (85.6 MMBTu/customer-yr heating service demand)	12.02	8.84	5.75	5.12	3.23
Natural Gas	The majority of residential customers heat their homes with natural gas and have average annual heating service demands of 59.1 MMBTu/customer-yr	8.34	6.13	3.99	3.53	2.24
Electric Resistance	Homes that currently use electric resistive heating tend to be smaller. Resistive heat being replaced by heat pumps reduces load. (25.1 MMBTu/customer-yr heating service demand)	--	-0.93	-1.84	-2.03	-2.58

Notes: Peak impacts shown are for single family homes in BGE. Other utility impacts vary slightly based on differences in customer heating demands. Impacts shown are the non-coincident peaks of the heating equipment only. ASHP + fossil backup has no electric peak impact during the coldest hours of the year, when it relies fully on backup equipment to heat the home.

4 – Transportation Sector Assumptions and Inputs

Calibrating to MD's Current EV Stock

The starting point for EV penetration is based on the best available data from public data sources

- LDV EV stock from MD DOT MVA Electric Vehicle Registration Data; allocated utilities based on zip code mapping
- MHDV starting stock based on the Maryland Open Data Portal registration data
  - Majority of existing MHDV EVs are electric school buses and passenger buses
- We assume all 91 existing EV school buses are in Pepco service territory
  - 86 school buses are currently in operation at 5 Montgomery County Public School Bus Depots. Montgomery County covers three utilities (mainly served by PEPCO)
  - An additional 240 buses are to be added by the end of the 2024-2025 school year
- We assume all 20 existing EV passenger buses are in BGE service territory
  - 7 battery electric buses deployed in early 2023 through MDOT MTA's first pilot ZEB program, at MTA Kirk Avenue Bus Division (served by BGE)

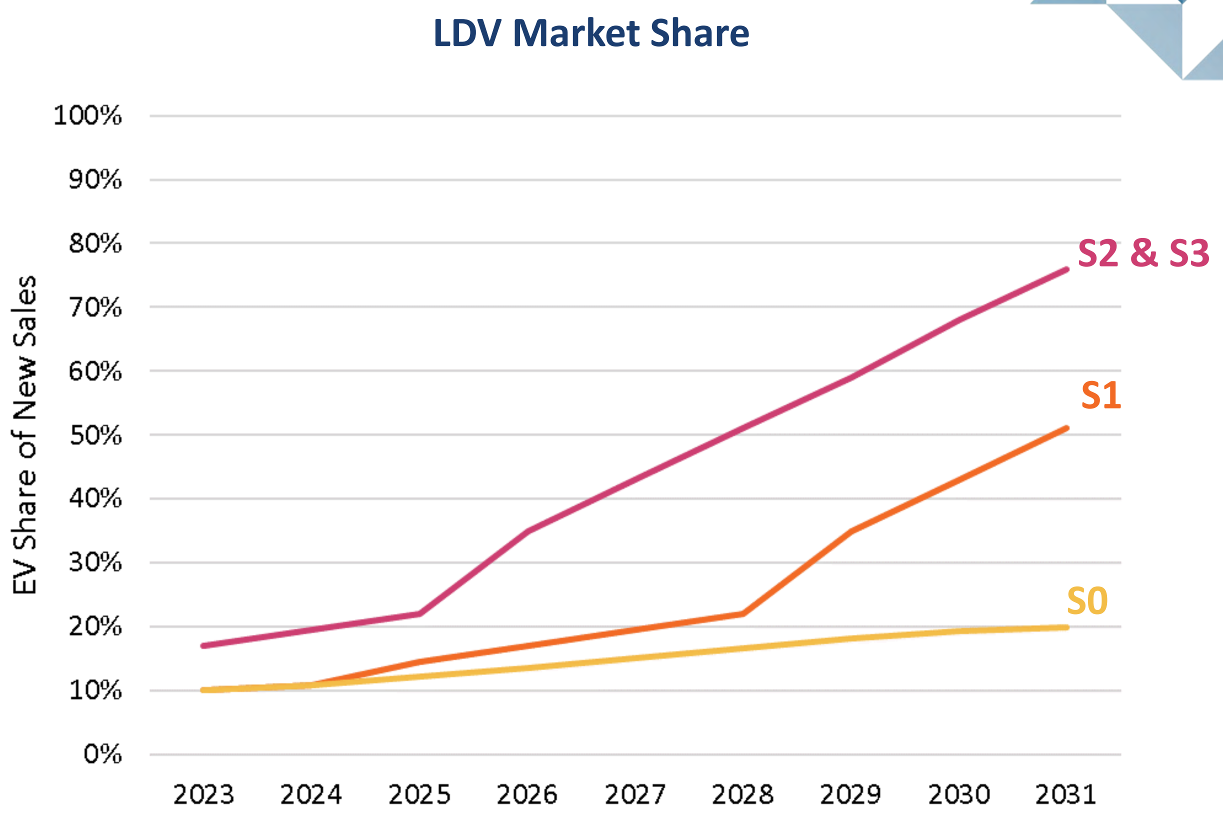
Assumed Electric Vehicle Starting Stock by Utility

	BGE	DPL	PEPCO	PE	Choptank	SMECO	In-Scope MD
LDV-BEV	18,394	1,103	13,950	4,211	301	1,735	39,694
LDV-PHEV	9,476	568	7,186	2,169	155	894	20,448
Class 2b-3 Light Truck	-	-	-	-	-	-	-
Class 4-8 Truck	20	-	-	-	-	-	20
Class 7-8 Tractor Trailer	2	-	-	-	-	-	2
School Bus	-	-	91	-	-	-	91
Total LDV	**27,870**	**1,671**	**21,136**	**6,380**	**456**	**2,629**	**60,142**
Total MHDV	**22**	**-**	**91**	**-**	**-**	**-**	**113**

LDV Adoption Curves

Because the scope of the study is more focused on studying the electrification of the building sector, we keep the same EV adoption curve in all S.2 and S.3 scenarios

- **S.2 and S.3 (Decarb. Scenarios):** Assume the standards set in the Advanced Clean Cars II (ACC II) regulation are met
  - 76% EV share of new sales by 2031
  - 1.0M EV LDVs on the road by 2031, or 22% of vehicles
- **S.1 (Low Electrification):** Based on annual EV sales growth rate from EIA Annual Energy Outlook for 2023-2025; assumes the ACC II standards are met with a 3-year delay for 2026-2031
  - 51% EV share of new sales by 2031
- **S.0 (Reference):** Based on annual EV sales growth rate from EIA Annual Energy Outlook 2023



LDV Adoption Modeling Methodology and Data Sources

LDV Stock = **2022 LDV Stock, by Fuel Type** + **New LDV Sales** - **LDV Retirements**

2022 LDV Stock, by Fuel Type:

- **2022 EV Stock**
  - **Source:** MD DOT MVA Electric Vehicle Registration data, allocated to utilities based on zip code mapping.
- **2022 ICE Stock**
  - **Source:** 2022 Total EV Stock subtracted from MVA MD Vehicle Registration data. Allocated to in-scope utilities using 2022 residential customer counts.

New LDV Sales:

- **Annual Total Vehicle Sales** ✖ **New Sales Share (%) by Fuel**
- **Annual Total Vehicle Sales**
  - **Source:** MDOT.
  - **Notes:** Sales are modeled based on growth in vehicle stock from MDE and an assumed vehicle lifetime. Allocated to utilities using forecasted customer counts.
- **New Sales Share (%) by Fuel**
  - **Source:** ACC II Regulation for share of new sales that must be zero emission.
  - **Notes:** Low electrification case assumes a 3-year delay on the ACC II regulation.

LDV Retirements:

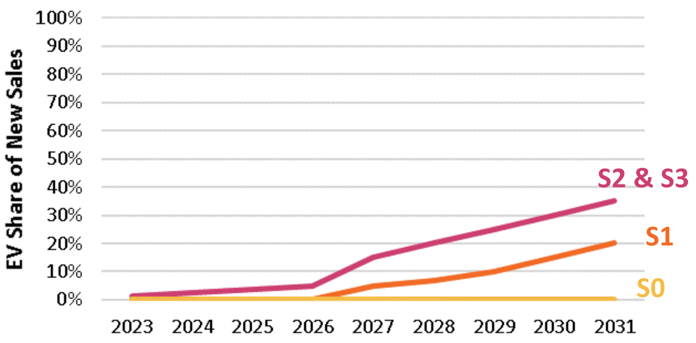
- **Source:** Assumed 18 year lifetime for LDVs, implicit in AEO projections.

MHDV Adoption Curves

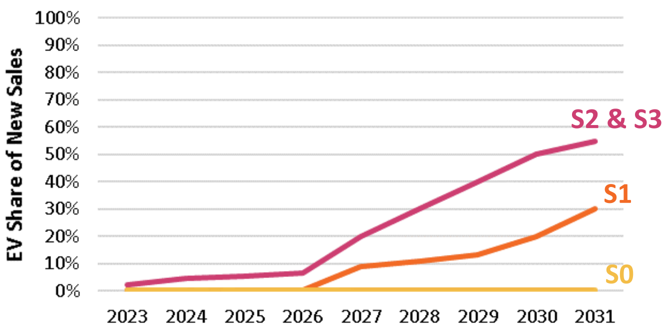
Because the scope of the study is more focused on studying the electrification of the building sector, we keep the same EV adoption curve in all S.2 and S.3 scenarios

- **S.2 and S.3 (Decarb. Scenarios):** Assumes the standards set in the Advanced Clean Trucks (ACT) regulation are met
  - 35% to 55% EV share of new sales by 2031 (varies by vehicle class)
  - Because MD's adoption of the ACT only starts in 2027, we set 2024-2026 EV penetration at half the level prescribed in the ACT. 2023 is interpolated between 2022 actuals and projected 2024
- **S.1 (Low Electrification):** Assumes the ACT standards are met with a 3-year delay
  - 20-30% EV share of new sales by 2031
- **S.0 (Reference):** Based on annual EV sales growth rate from EIA Annual Energy Outlook 2023

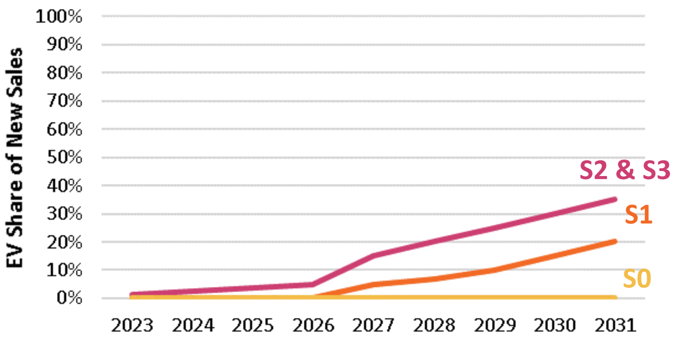
Class 2b-3



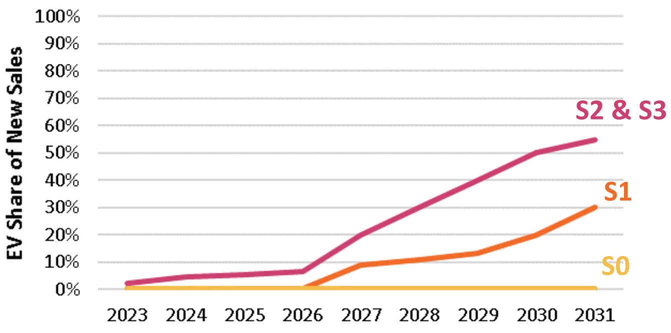
Class 4-8



Class 7-8 Tractor



School Bus



MHDV Adoption Modeling Methodology and Data Sources

MHDV Stock = 2022 MHDV Stock, by Fuel Type & Class + New MHDV Sales by Class - MHDV Retirements by Class

2022 MHDV Stock, by Fuel Type & Class:

- **2022 EV Stock**
  - **Source:** MDOT Electric Vehicle Registrations by Classification.
  - **Notes:** We allocate all existing electric school bus stock to PEPCO and all electric transit bus and tractor stock to BGE, due to news announcements.
- **2022 ICE Stock**
  - **Source:** MDOT.
  - **Notes:** MHDV stock taken directly from MDOT dataset. Maryland-level data scaled to utility-level based on county level diesel consumption.

New MHDV Sales by Class = Annual Total Vehicle Sales × New Sales Share (%) by Fuel

- **Annual Total Vehicle Sales**
  - **Source:** MDOT.
  - **Notes:** Sales are modeled based on growth in vehicle stock from MDOT and an assumed vehicle lifetime.
- **New Sales Share (%) by Fuel**
  - **Source:** Advanced Clean Trucks Act starting in 2027.
  - **Notes:** Low electrification case assumes a 3-year delay on the ACT regulation.

MHDV Retirements by Class

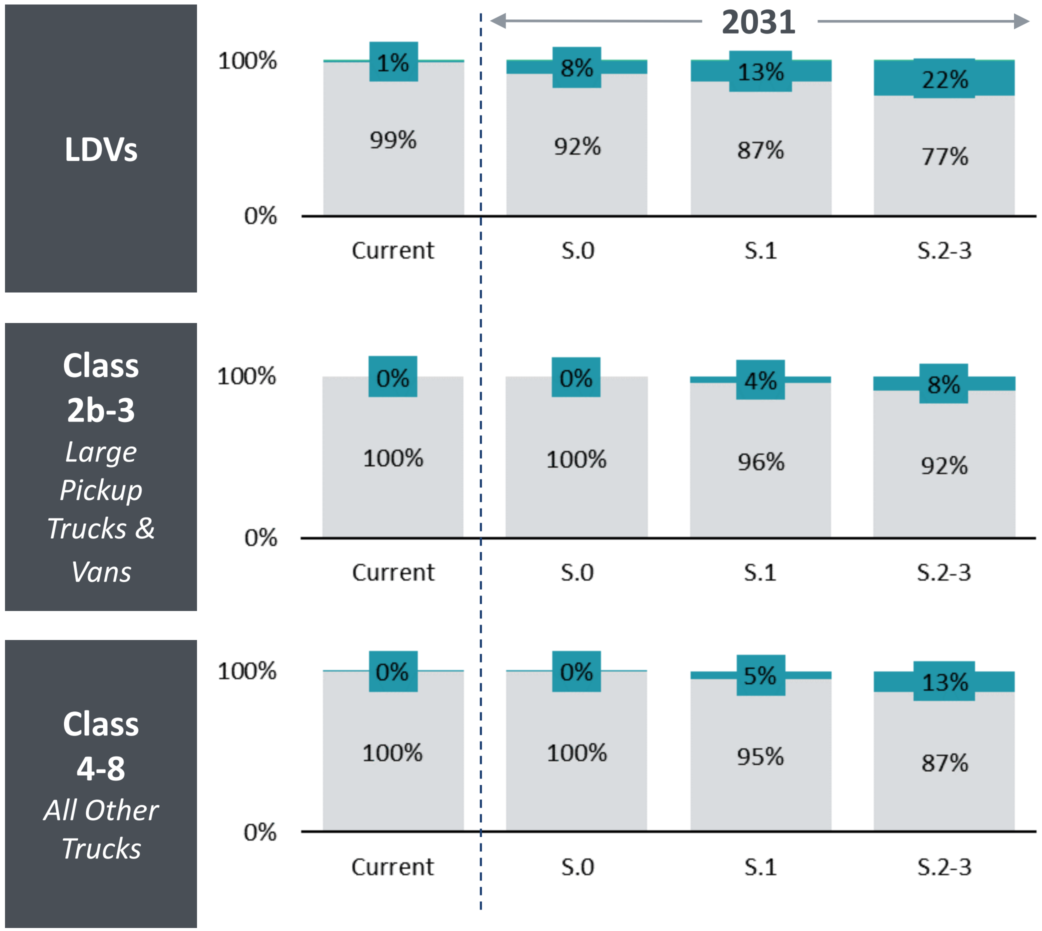
- **Assumption:** 18 year lifetime. No advanced retirements

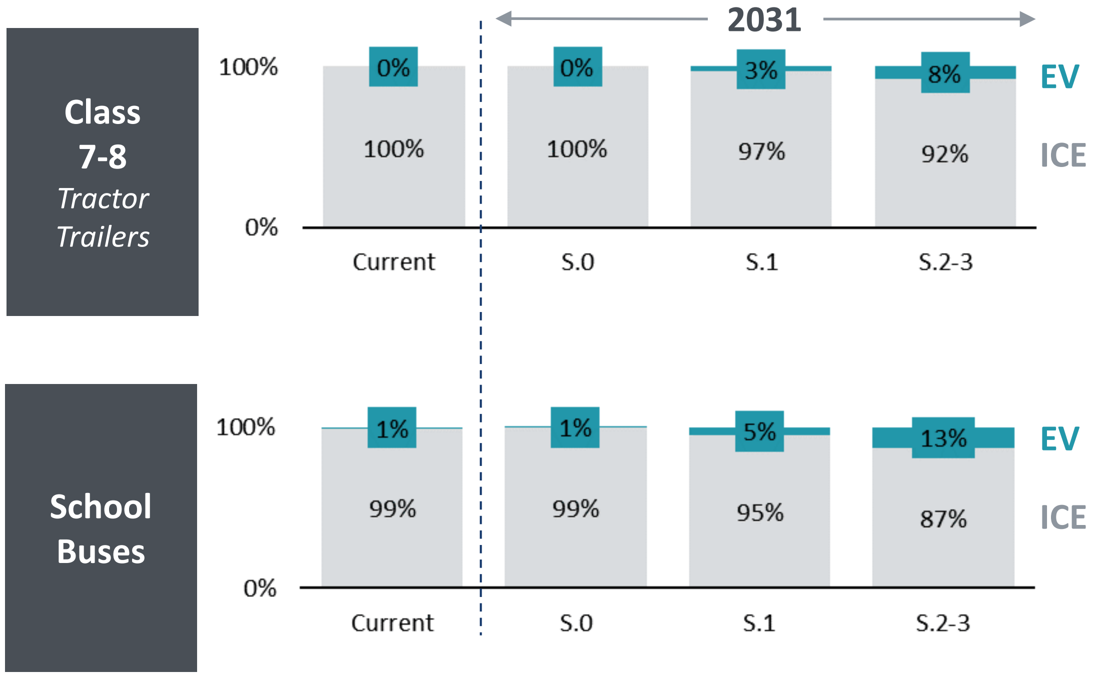
S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

EV Penetration Scenarios - Statewide

Electric Vehicle Penetration by Weight Class, *% of on-road vehicles*

Charts show state level data – inter-utility variation is negligible





LDV = light-duty vehicle, EV = electric vehicle, ICE = internal combustion engine

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

EV Penetration Scenarios by Utility

Electric Vehicle Stock by Weight Class, *# of on-road electric vehicles*

2031 Electric Vehicle Stock						
Vehicle Class	BGE	Choptank	DPL	PEPCO	Potomac Edison	SMECO
S.0						
LDV	203,868	8,058	29,414	98,425	44,695	28,045
Class 2b-3	161	4	24	80	49	14
Class 4-8	82	2	11	36	22	6
Class 7-8	18	0	3	9	5	2
School Bus	6	0	1	48	2	1
S.1						
LDV	325,850	13,070	47,713	155,237	71,722	45,545
Class 2b-3	4,145	103	610	2,045	1,254	367
Class 4-8	3,347	83	491	1,647	1,010	295
Class 7-8	550	14	81	271	166	49
School Bus	270	7	40	179	82	24
S.2 - S.3						
LDV	560,459	22,735	82,995	263,910	123,144	78,692
Class 2b-3	9,802	243	1,442	4,836	2,966	867
Class 4-8	8,525	211	1,253	4,201	2,576	753
Class 7-8	1,306	32	192	644	395	116
School Bus	688	17	101	385	208	61

Vehicle miles traveled (VMT) Forecast

Electric vehicle load impacts are quantified based on stock forecasts and annual VMTs

- VMT forecasts based on MDOT forecast
- LDV VMTs are allocated to utilities based on residential customer counts
- MHDV VMTs are allocated to utilities based on county shares of state diesel fuel sales and county-to-utility mapping

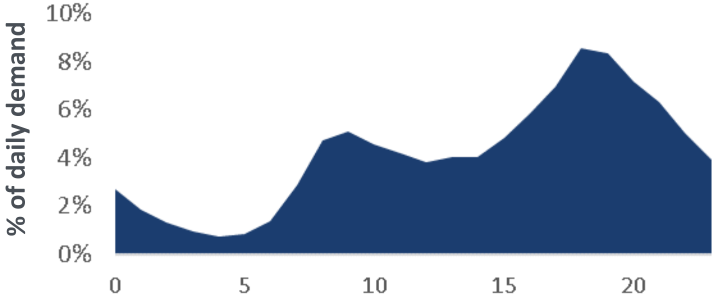
Projected VMT in Maryland by Vehicle Category (million miles)

Vehicle Category	2022 VMT (million miles)	2031 VMT (million miles)	CAGR (%)
Light-Duty Vehicles	47,959	52,009	0.90%
Class 2b-3 Light Truck	2,861	3,159	0.98%
Class 4-8 Truck	1,796	1,975	0.94%
Class 7-8 Tractor Trailer	2,310	2,541	0.95%
School Bus	220	239	0.85%

Sources and Notes:
MDOT-provided VMT forecast.

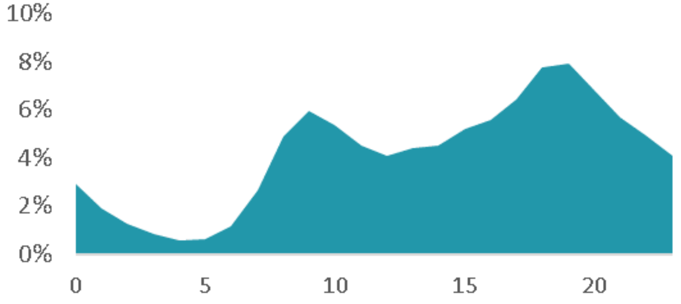
Electric Vehicle Load Shapes

LDV-BEV



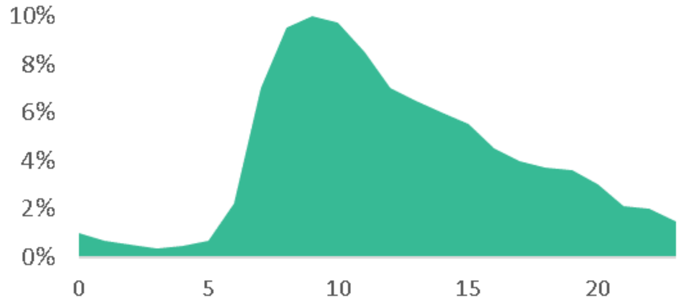
Source: EVI Pro-Lite

LDV-PHEV



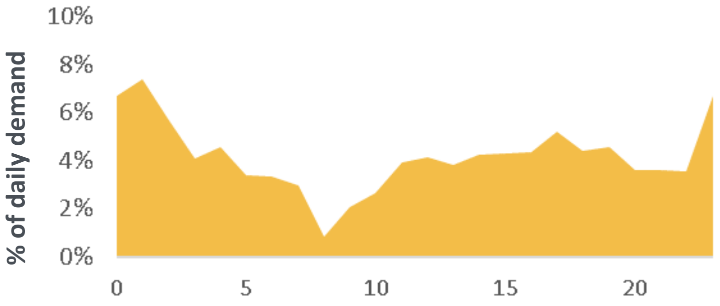
Source: EVI Pro-Lite

Class 2b-3



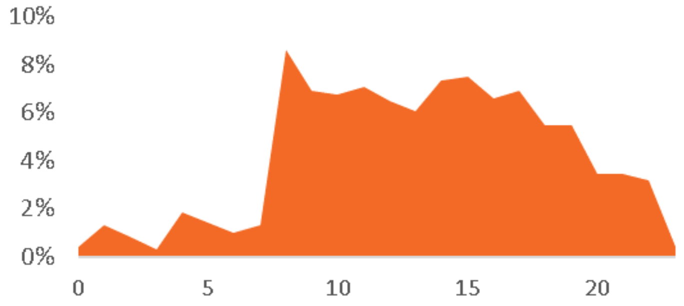
Source: California Load Shapes Report
Notes: We assume the commercial LDV load shape is representative of this vehicle class.

Class 4-8 Truck



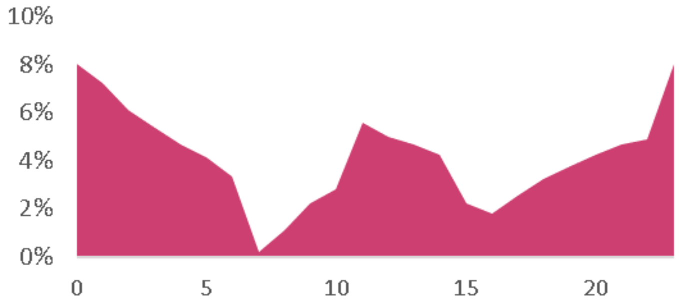
Source: 2023 ICCT Report
Notes: The profile is an aggregated profile of all class 4-8 trucks. The ICCT report utilized the HEVI-LOAD tool which is the same tool used in the California reports.

Class 7-8 Tractor Trailer



Source: 2021 California Report
Notes: Specifically, the tractor-trailer load shape is used for this category.

School Bus



Source: 2021 California Report
Notes: Specifically, the school bus load shape is utilized.

Profiles show natural charging profiles, without any utility TOU or programs to incentivize off peak charging.

5 – Distributed Energy Resources and Demand Side Management Inputs

Distributed Energy Resource Penetration

Distributed (i.e., behind-the-meter) solar and storage growth in all scenarios is based on results from the Power Plant Research Program (PPRP) 100% RPS Study BAU Case

- The current capacity is also sourced from the PPRP study for consistency
- We use the same solar projection in all scenarios, including Reference and Low Electrification, because the RPS achievement trajectory is consistent with the level of annual solar adoption already occurring
- BAU and High EE and load flexibility cases have the same BTM solar and storage assumptions
  - Storage capacity in the BAU case does not impact load since none of the utilities currently have a storage DR program
  - Only a portion of distributed storage is assumed to participate in utility programs based on achievable program participation

Distributed Solar Capacity by Utility (MW)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
All Scenarios										
BGE	610	650	692	736	804	875	947	1,022	1,099	1,159
DPL	71	76	81	86	94	103	111	120	129	136
Potomac	118	126	134	143	156	170	184	198	213	225
PEPCO	306	326	348	369	404	439	476	513	552	582
SMECO	78	83	88	94	103	112	121	130	140	148
Choptank	21	22	24	25	28	30	33	35	38	40
MD Total	**1,204**	**1,285**	**1,368**	**1,453**	**1,589**	**1,728**	**1,872**	**2,020**	**2,172**	**2,290**

Distributed Storage Capacity by Utility (MW)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
All Scenarios										
BGE	20	23	27	30	37	219	238	259	260	262
DPL	2	3	3	4	4	26	28	30	31	31
Potomac	4	5	5	6	7	42	46	50	51	51
PEPCO	10	12	14	15	19	110	119	130	131	132
SMECO	3	3	3	4	5	28	30	33	33	33
Choptank	1	1	1	1	1	8	8	9	9	9
MD Total	**40**	**46**	**54**	**59**	**73**	**432**	**469**	**511**	**514**	**518**

Source: 100% RPS Study

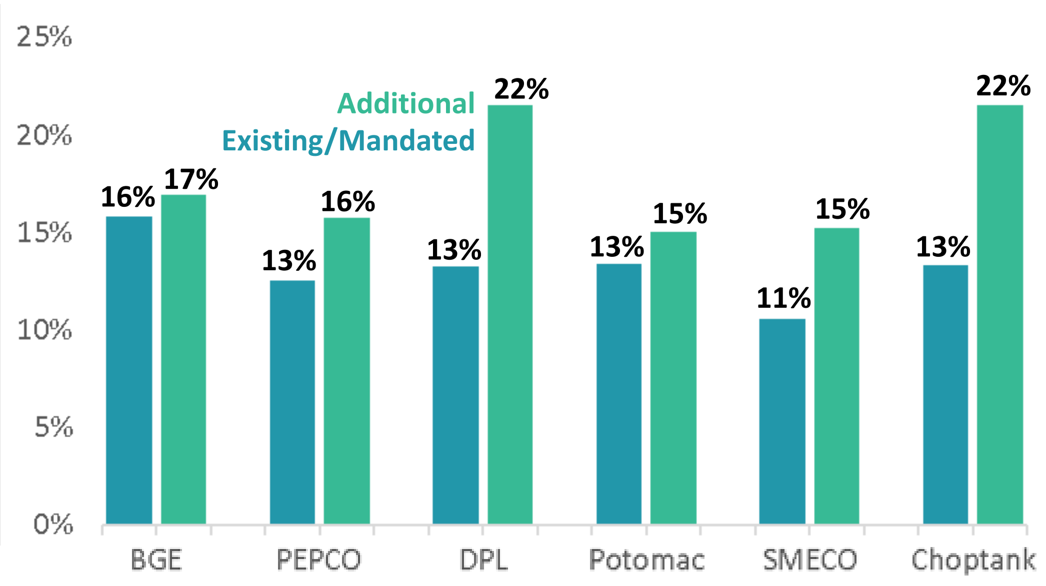
Energy Efficiency Assumptions

Energy efficiency assumptions are based on the EmPOWER 2024-2026 program cycle plans filed by the utilities in August

- **Existing/Mandated DSM Programs Case:** We map the BAU Case to utilities' filed "2023 Scenario", which was defined based on current EE programs and current statutory requirements
- **Additional DSM Programs Case:** We map the High Case to utilities' filed "Maximum Achievable Scenario", which was defined as the set of programs and measures that result in maximum savings at a higher spending level
- We remove all heating and cooling related programs from EE accounting as efficiency improvements for those end uses are accounted for within our model
- We assume Choptank EE deployment is comparable to DPL's as Choptank is not an EmPOWER utility

Energy Efficiency Assumptions

2031 EE as % of 2022 Actual Consumption



Source: August 1st, 2023 utility filings in Case No. 9705

Load Flexibility Participation Assumptions

Electric utilities can reduce electrification peak load growth impacts by deploying load flexibility programs:

- Existing/Mandated DSM Programs Case assumes existing load flexibility programs continue, without growth
- Existing utility load flexibility impacts are accounted for in Ten Year Plan forecasts sourced from utilities
- Additional DSM Programs Case assumes growth in existing program participation and deployment of new Demand Response (DR) programs, representing advanced but achievable deployment
- Additional DSM Programs Case participation ramps up from current levels (low for most utility programs) to end state participation by 2031, following S-curve adoption
- Program impact assumptions are based on existing MD programs and pilot data when applicable, or data from other jurisdictions, tailored to MD customer characteristics. See following slides for more information

Load Flexibility Participation Assumptions

Additional DSM Programs Case participation ramps up from current levels (low for most utility programs) to end state participation by 2031, following S-curve adoption

Program	Description	Existing Participation	Additional Case Participation
Residential			
Time-of-use (TOU)	Time varying pricing signals, consistent with proposed utility rates	0%	15%
Peak time rebate (PTR)	Residential customers reduce load during called event hours	BGE, Pepco, DPL: 90% (assume limited use of the program and that impacts are not reflected in utility forecasts) SMECO, Choptank, Potomac Edison: 0%	90%
Smart thermostat	Customers reduce cooling or heating load by adjusting thermostats during utility called events (<20/yr)	Summer: BGE (28%, 342,000 customers); Pepco (38%, 206,012 customers); DPL (20%, 33,844 customers); SMECO, Choptank, Potomac Edison (0%) Winter: 0% for all utilities	Summer (~+25%pt from existing): BGE (55%); Pepco (65%); DPL (45%); SMECO, Choptank, Potomac Edison (25%) Winter: 25% for all utilities
Smart water heating	Customers shift heat water during off peak hours on a frequent (daily) basis	0%	30%
Commercial			
Smart thermostat	Small commercial customers reduce cooling or heating load by adjusting thermostats during utility called events (<20/yr)	0%*	25%
Automated demand response (DR) – HVAC	Automated control of customer heating and cooling demand. Only applicable to large (Covered) customers	0%	10%
Interruptible tariff	Large customers (Covered) reduce load during called events. Events are infrequent (<10/yr)	0%	15%
Additional Programs			
Managed electric vehicle charging	Customers are incentivized to charge in off peak hours and shift EV load out of daily peak periods	0%	30% (all vehicle classes)
Behind-the-meter battery storage	Utilities can call on batteries to charge and discharge during event hours (70 events/yr). Assume only a portion of BTM storage capacity from the PPRP study enrolls in utility programs	0%	30% of BTM storage capacity

*Note: Pepco and DPL have commercial smart thermostat programs, but participation is negligible. Participation expressed as % of eligible customers.

Load Flexibility Program Impact Assumptions

Program impacts are modeled on a per-participant basis. See following slides for assumption justifications

Program	% of Load Shifted	# of Hrs Shifted from	# of Hrs Shifted to
Residential			
Time-of-use (TOU)	10% (summer); 5% (winter)	5 (summer); 3 (winter)	7 (summer); 8 (winter)
Peak time rebate (PTR)	5%	3	5
Smart thermostat	60% (cooling); 20% (heat pump space heating); 40% (electric resistance space heating)	3	6
Smart water heating	Modeled by shifting water heating load out of system peak windows. Maximum impact is 50% of hourly water heating load shifted out of peak hours	8	16
Commercial			
Smart thermostat	20% (cooling); 5% (heat pump space heating); 10% (electric resistance space heating)	3	6
Automated demand response (DR) – HVAC	60% (cooling); 15% (heat pump space heating); 30% (electric resistance space heating)	3	6
Interruptible tariff	20%	3	0
Additional Programs			
Managed electric vehicle charging	Modeled by shifting charging load out of system peak windows. Maximum impact is 50% of hourly vehicle charging load (on average, across all vehicles) shifted out of peak hours	6	18
Behind-the-meter battery storage	Impacts modeled at aggregate level. Maximum per customer impact is per customer battery storage capacity	4	7

Notes: '% of Load Shifted' refers to the percent of applicable end use load that is curtailed during each load flexibility event.

Load Flexibility Sources Considered

Program impacts are based on MD programs and pilot data when applicable, or data from other jurisdictions, tailored to MD customer characteristics

Program	Sources Considered
Residential	
Time-of-use (TOU)	Impacts based on Maryland PC44 Time of Use Pilots: End-of-Pilot Evaluation
Peak time rebate (PTR)	Impacts based on Brattle's database of time-varying pricing offerings, Arcturus 3.0
Smart thermostat	Impacts based on Brattle review of third-party reports analyzing thermostat DR operations: CenterPoint, Cadmus (2022); Indianapolis Power & Light, Cadmus (2020); KCP&L, Navigant (2017); PGE 2017/2018 electric BYOT program; Michigan electric DR potential study; ACEE study of DR for electric baseboard heating in Quebec; Pepco DR Electrification Study (FC 1167)
Smart water heating	Assumptions for grid interactive water heating and static timed water heating are derived from studies, for example, Ryan Hledik, Judy Chang, and Roger Lueken. "The Hidden Battery: Opportunities in Electric Water Heating." January 2016
Commercial	
Smart thermostat	Impacts based on Brattle review of third-party reports analyzing thermostat DR operations: CenterPoint, Cadmus (2022); Indianapolis Power & Light, Cadmus (2020); KCP&L, Navigant (2017)
Automated demand response (DR) – HVAC	The potential for C&I customers to provide around-the-clock load flexibility was primarily derived from data supporting a 2017 statewide assessment of DR potential in California, a 2013 LBNL study of DR capability, and electricity load patterns representative of C&I buildings developed by the U.S. Department of Energy
Interruptible tariff	Impacts based Brattle analysis of FERC data on utility DR programs in other jurisdictions
Additional Programs	
Managed electric vehicle charging	The ability to curtail charging load is guided by a review of utility EV charging DR pilots, including managed charging programs at several California utilities (PG&E, SDG&E, SCE, and SMUD) and United Energy in Australia
Behind-the-meter battery storage	Impacts based on full dispatch of behind-the-meter battery with assumed average capacity of 5 kW / 15 kWh

6 – Emissions and Gas Consumption Results

Calibrating Emissions to MDE Climate Pathway

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

2031 Maryland[1] Total Fuel Consumption and Emissions from Building Sector Space and Water Heating

		S.0	S.1	S.2A	S.2B	S.3A	S.3B	MDE Climate Pathway
Fuel Consumption *Million MMBTU*	**Gas**	94.9	91.5	80.8	63.1	61.7	61.7	76.4
	Liquid Fuels	27.2	25.5	22.1	19.1	18.9	18.9	14.6
	Total Fossil	122.1	116.9	102.9	**82.2**	**80.6**	**80.6**	**90.9**
	2022-2031 % Change	4.2%	-0.2%	-12.2%	**-29.8%**	**-31.2%**	**-31.2%**	**-30.1%**
Direct Emissions *Million Metric Tons CO_2e*	**Gas**	5.05	4.87	4.30	3.35	3.28	3.28	4.06
	Liquid Fuels	2.05	1.92	1.67	**1.44**	**1.43**	**1.43**	**1.01**
	Total Fossil	7.10	6.79	5.97	**4.80**	**4.71**	**4.71**	**5.07**
	2022-2031 % Change	4.1%	-0.5%	-12.5%	**-29.6%**	**-31.0%**	**-31.0%**	**-30.0%**

The High Electrification and Hybrid with Fuel Backup scenarios roughly match the MDE Climate Pathway's emission reductions from space and water heating.

Note: Tables include fuel and emissions from direct fossil fuel consumption for residential and commercial space and water heating. Total fossil liquids were modeled separately as oil and propane, and combined in tables above for comparison with MDE categories. MDE data is based on consumption by end use, customer type, and fuel type. Emissions are calculated from fuel consumption based on emission factors based on 20-year global warming potential from EPA (consistent with MDE's modeling).

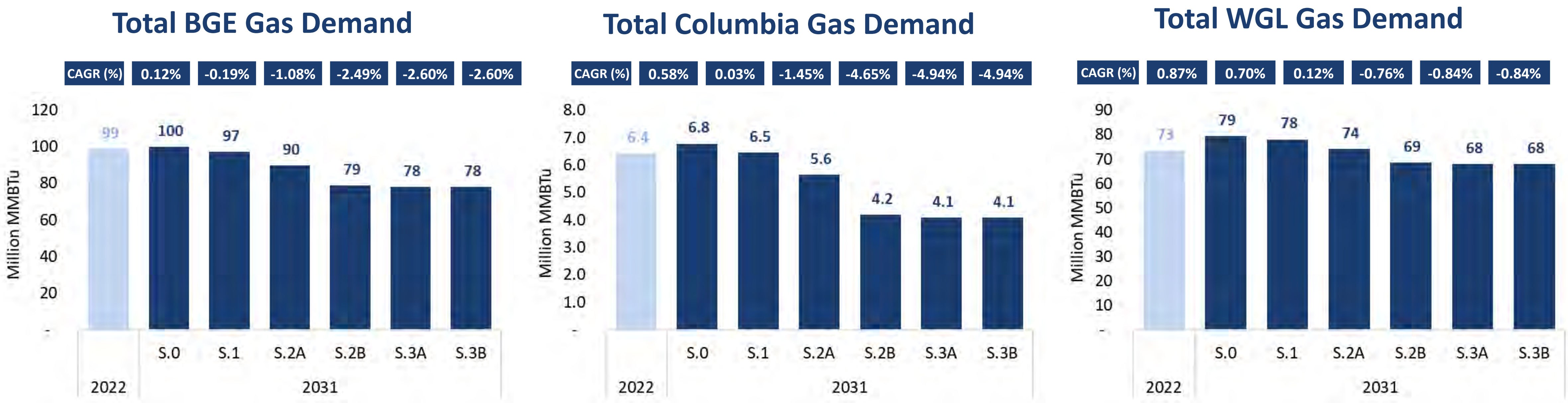
1 Does not include out-of-scope utilities

Gas Demand Impacts by Utility

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

2022-2031 Annual Total Gas Demand by Scenario and Utility

Gas demand will decrease significantly in the high electrification scenarios



Notes: 2022 and S.0 2031 natural gas demand are based on each utility's load forecast. Since WGL's forecast ends in 2027, Reference Case 2031 load was projected by Brattle based on WGL's forecasted 2020-27 load growth rate. 2031 natural gas demand in other scenarios is based on the modeled reduction in gas usage for space and water heating relative to S.0. None of the other end uses of natural gas (e.g., industrial) are assumed to change in this study.

7 – Existing/Mandated DSM Programs Case Results

Insights from Existing/Mandated DSM Programs Case Results

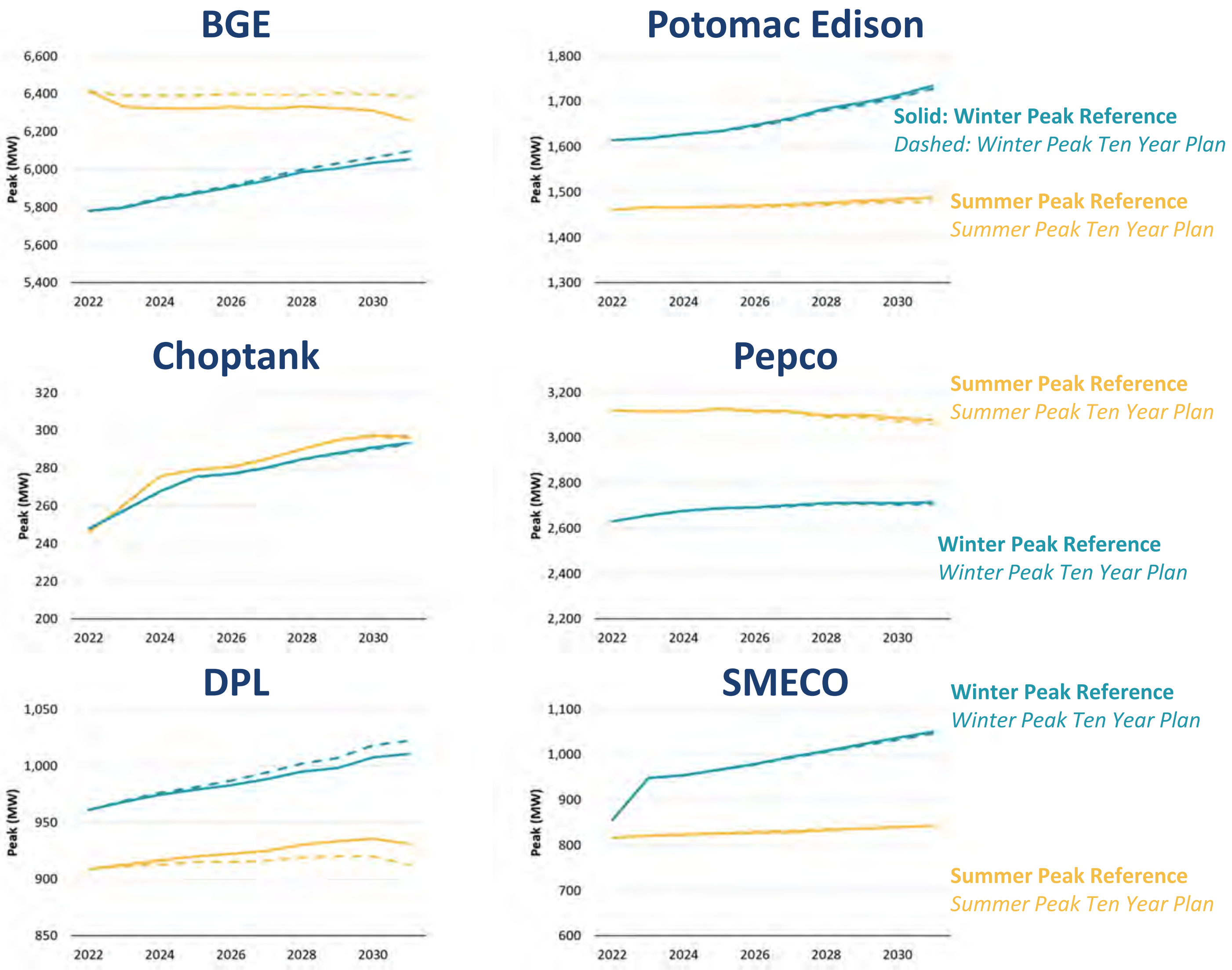
- There is a high degree of variation between utilities even in the **Reference Scenario**, which is based on utility Ten Year Plans and contain no assumed building electrification
  - We aligned utilities' EV and BTM solar forecasts, but did not make any other adjustments
  - **CAGRs range from -0.27% (BGE) to 2.30% (SMECO)** under the Reference case for 2022-2031 peak load growth
- **High Electrification with Legacy Tech (S.3B)** results in the highest load growth across utilities, as expected
  - **CAGRs range from 1.15% (Pepco) to 3.45% (SMECO)**
- **High Electrification with Best-in-Class Tech (S.3A)**, where most electrification was assumed to occur with cold climate heat pumps, shows significantly lower load growth than S.3B
  - **CAGRs range from 0.24% (Pepco) to 2.39% (SMECO)**
  - Note that these CAGRs show very limited additional load growth relative to what is already in the Reference scenario
  - This is due to the assumption that resistance heater sales (including resistance backup) will fall to zero by 2030; cold climate heat pumps are twice as efficient as resistance heat at 5F
- All summer peaking utilities **switch to winter peaking** by 2030 in S.3B
- **The Hybrid scenarios (S.2A and S.2B)** have significantly lower load growth than S.3B, but show negligible load differences (if any) relative to S.3A

Note: Business-as-Usual (BAU) energy efficiency (EE) and load flexibility assumes current EE and DR program impacts, consistent with utility forecasts

Utility Ten Year Plans and Reference Scenario

We develop the Reference Scenario for this study from the 2022 Ten Year Plan filings

- Because each utility had different assumptions in their Ten Year Plan load forecasts, we made adjustments to align the utility forecasts for the Reference Scenario
  - Distributed solar forecasts adjusted to be consistent with RPS achievement trajectory (and PPRP study) across utilities
  - EV forecasts adjusted to follow the EIA Annual Energy Outlook trajectory and align all utility forecasts in the reference scenario; largest impact on BGE because we assume EIA growth, which is less aggressive than their Ten Year Plan assumptions
- Other than the above changes implemented to create a consistent comparison case, the Reference Scenario is the same as the Ten Year Plan forecasts
  - Pepco and BGE forecast a slight peak decline by 2031
  - Choptank and SMECO model >1.0% annual peak growth through 2031



Note: Choptank is not forecasted in Ten Year Plan and is instead compared to the utility-provided forecast. Chart axes differ across utilities and do not start a zero. In the charts above, Ten Year Plan forecasts are represented as dashed lines and solid lines are the Reference Case in this study. Summer peaks are shown in yellow and winter peaks in blue.

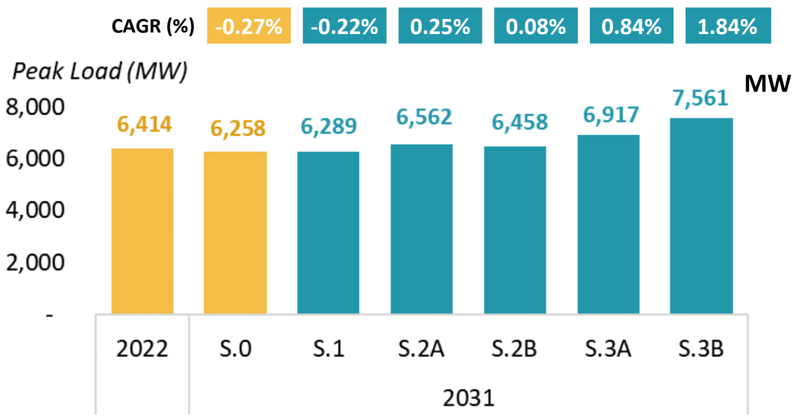
Summary of Results by Utility and Scenario

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

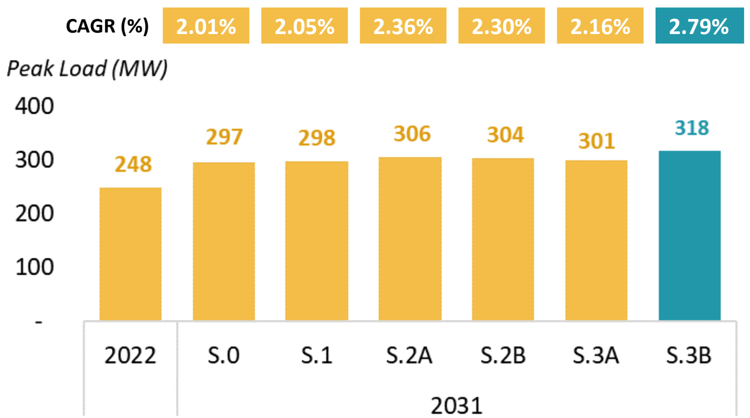
2022-2031 Peak Load Growth by Scenario

Utilities that are currently ***summer peaking*** *become* ***winter peaking*** *in some scenarios, with* ***Existing/Mandated DSM***

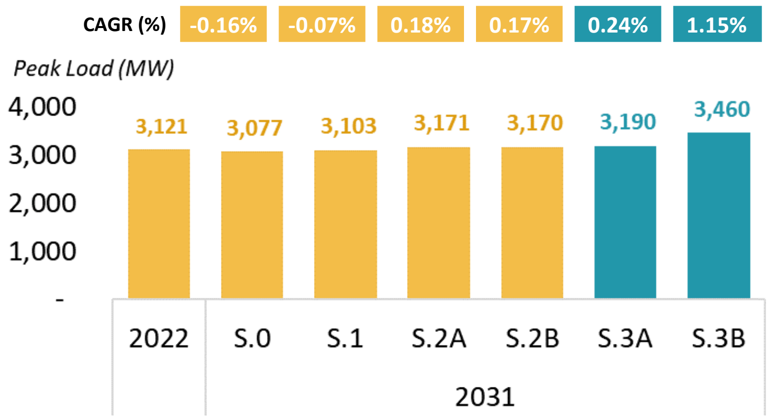
BGE



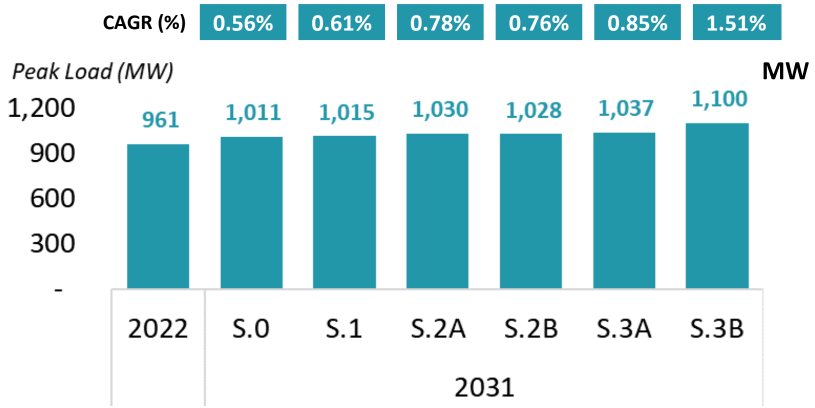
Choptank



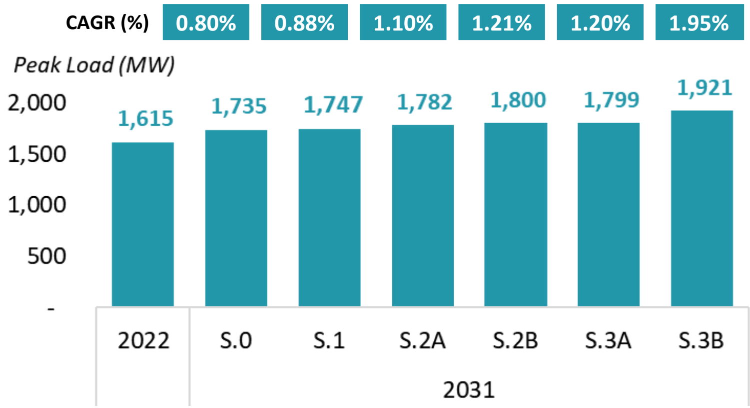
Pepco



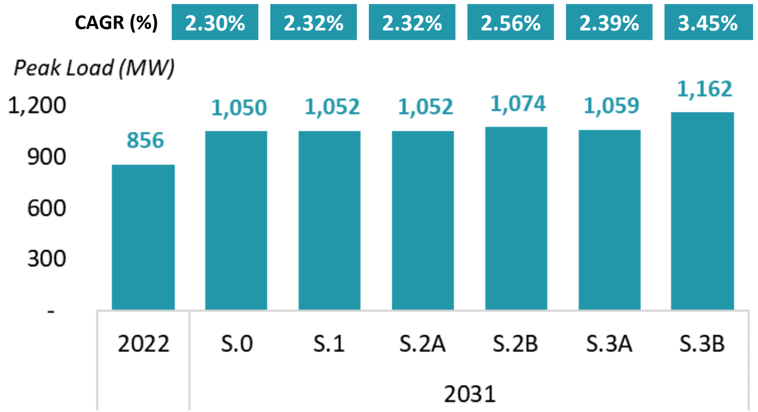
DPL



Potomac Edison



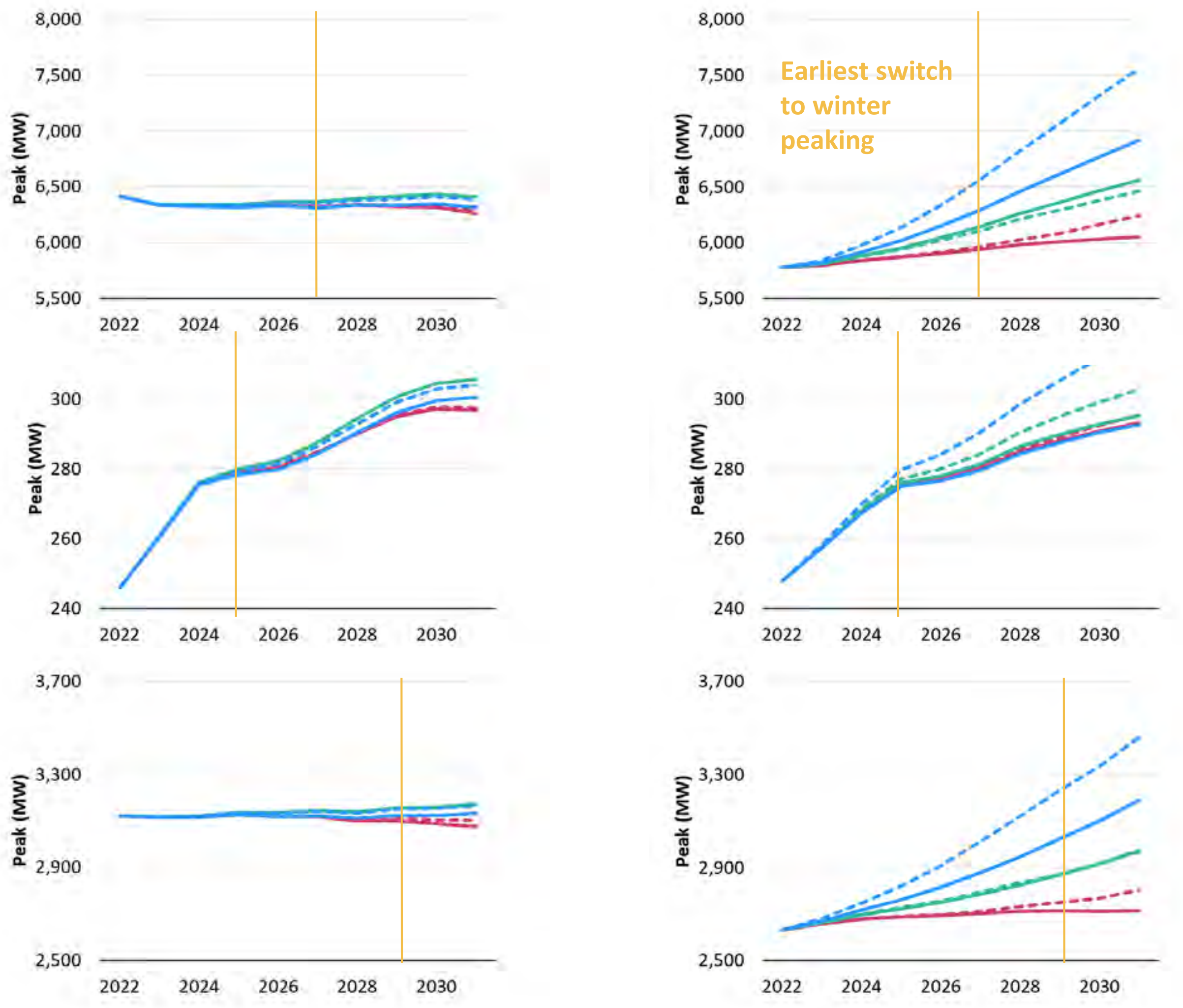
SMECO



Notes: Y-axis scales differ across charts. 2022 peak load is sourced from 2022 Ten Year Plan or utilities directly.

Summer and Winter Load Growth

	Summer	Winter
BGE		
Choptank		
Pepco		



S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

Vertical axis scale differs across charts.

Annual Energy Consumption by End Use

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

2023-2031 Annual Electricity Consumption by End Use, *GWh*

BGE

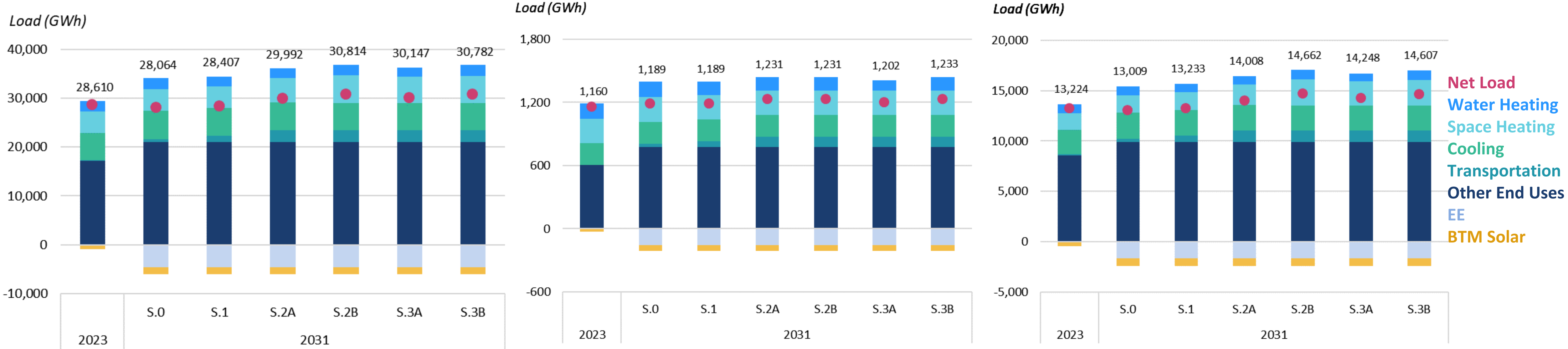
CAGR	-0.24%	-0.09%	0.59%	0.93%	0.66%	0.92%

Choptank

CAGR	0.31%	0.31%	0.75%	0.74%	0.45%	0.76%

Pepco

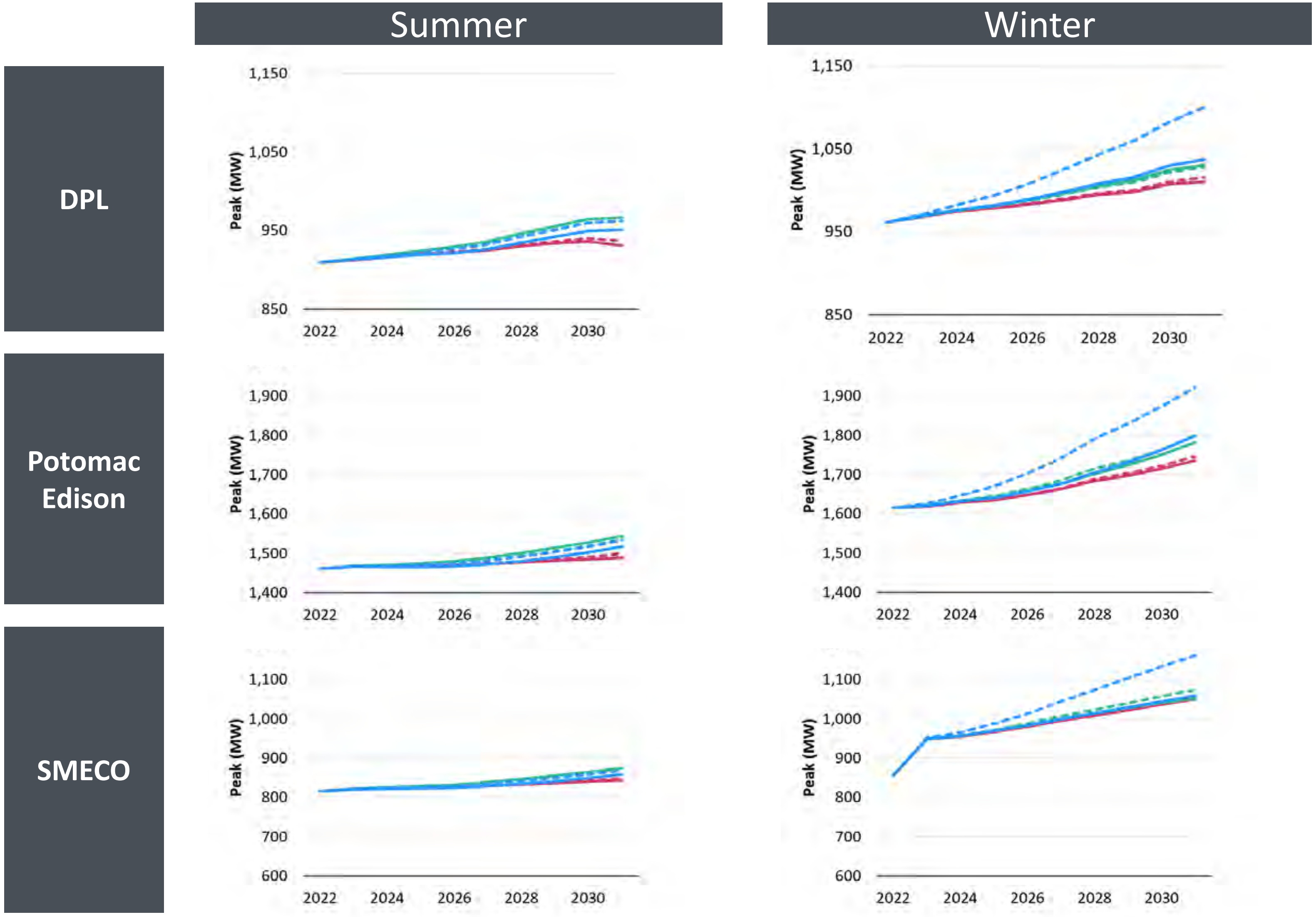
CAGR	-0.20%	0.01%	0.72%	1.30%	0.94%	1.25%



Notes: Vertical axis scale differs across charts.

EXISTING/MANDATED DSM PROGRAMS CASE RESULTS

Summer and Winter Load Growth



S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

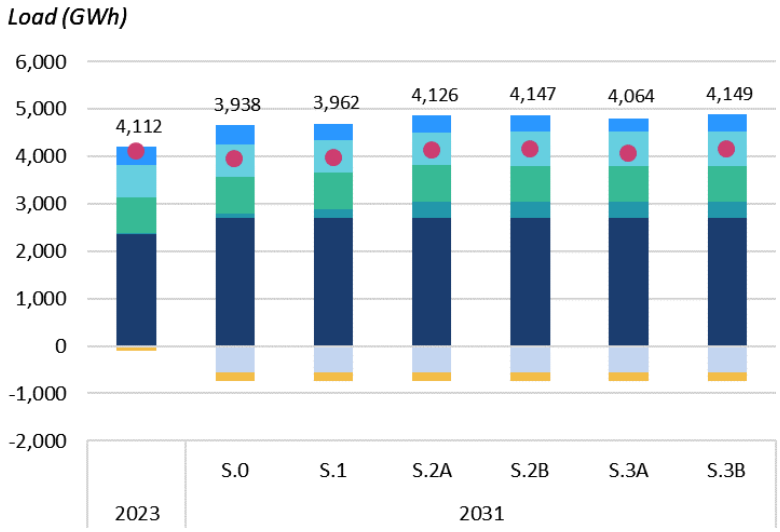
Note: In the Ten Year Plan, SMECO forecasts a 92 MW increase in winter peak load from 2022 to 2023. Vertical axis scale differs across charts.

Total Annual Energy

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

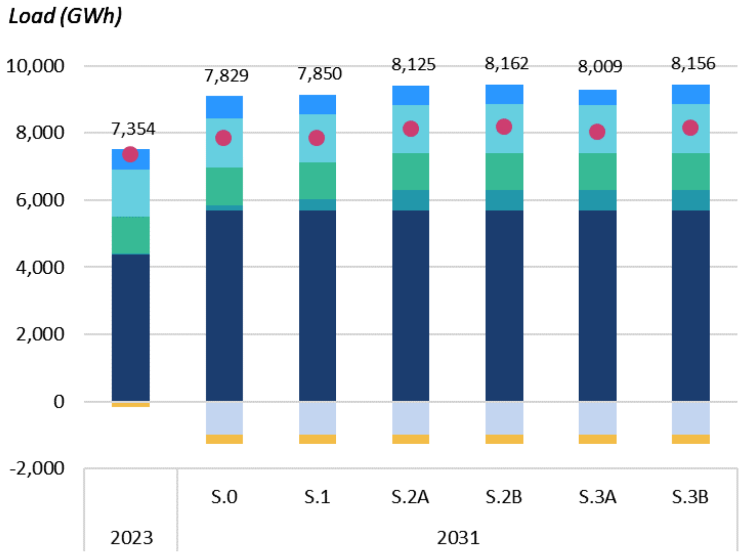
DPL

CAGR	-0.54%	-0.46%	0.04%	0.10%	-0.15%	0.11%



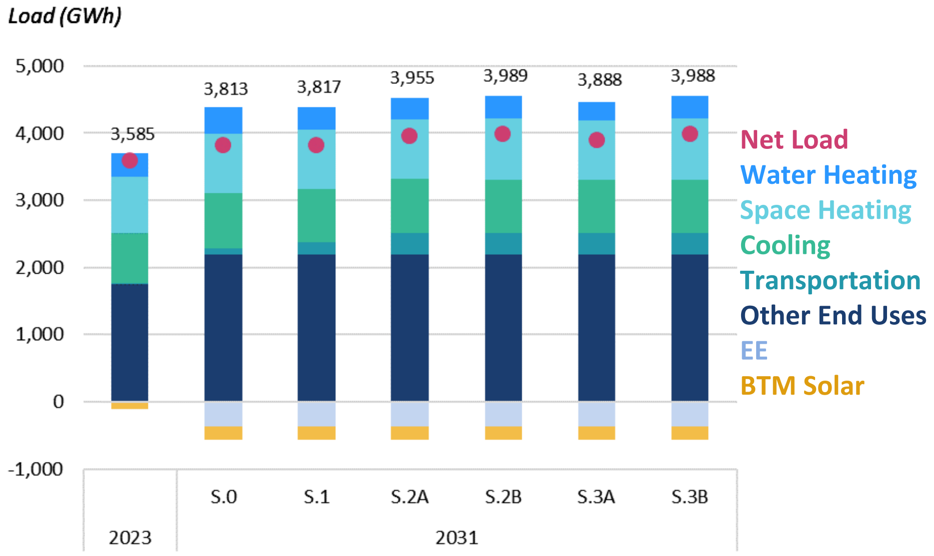
Potomac Edison

CAGR	0.79%	0.82%	1.25%	1.31%	1.07%	1.30%



SMECO

CAGR	0.78%	0.79%	1.24%	1.35%	1.02%	1.34%



Notes: Vertical axis scale differs across charts.

8 – Additional DSM Programs Case Results

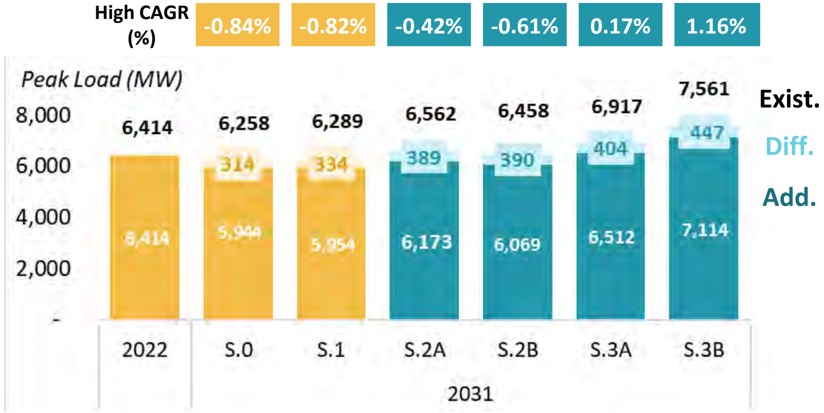
Summary of Results by Utility and Scenario

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

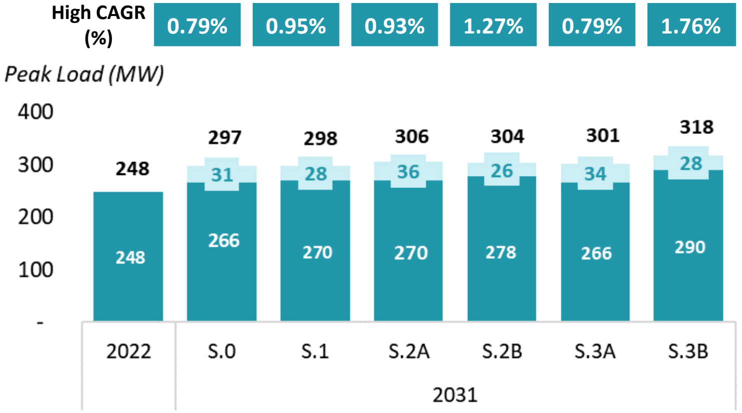
2022-2031 Peak Load Growth by Scenario

*Utilities see less **summer** and **winter** peak load growth with **Additional DSM** than in the Existing/Mandated DSM Cases*

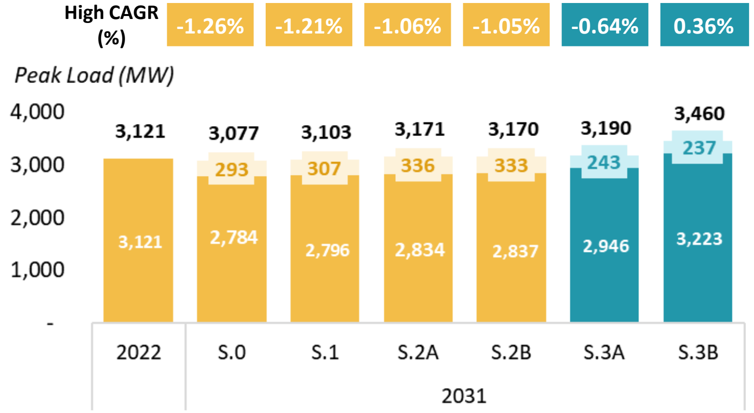
BGE



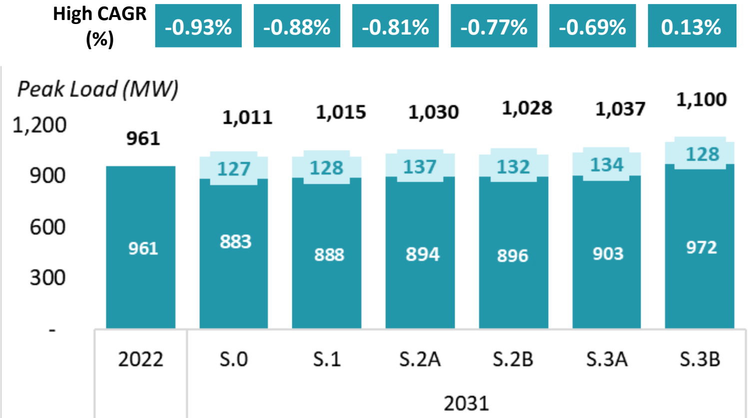
Choptank



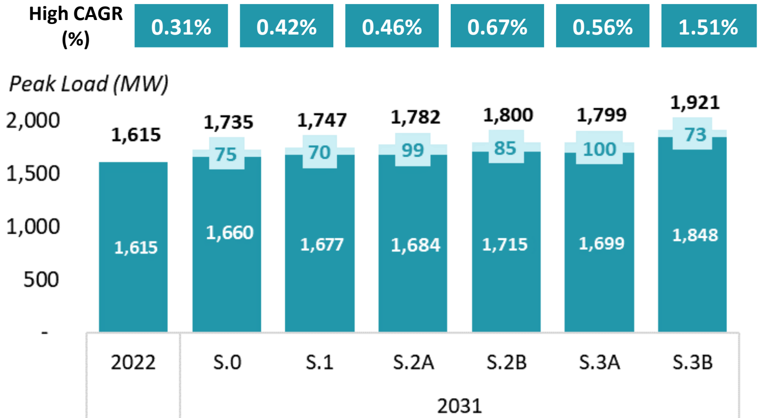
Pepco



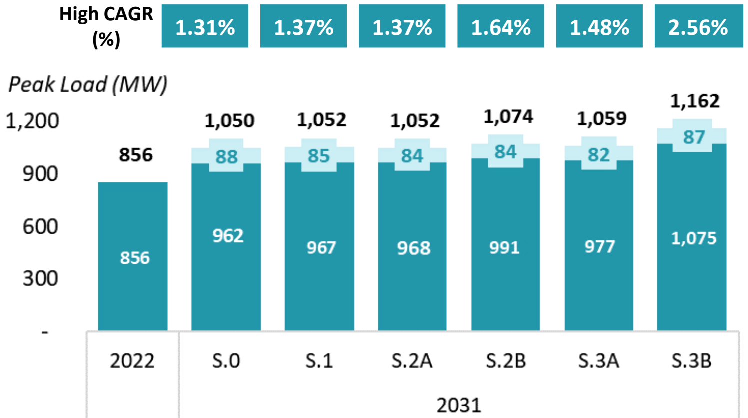
DPL



Potomac Edison



SMECO



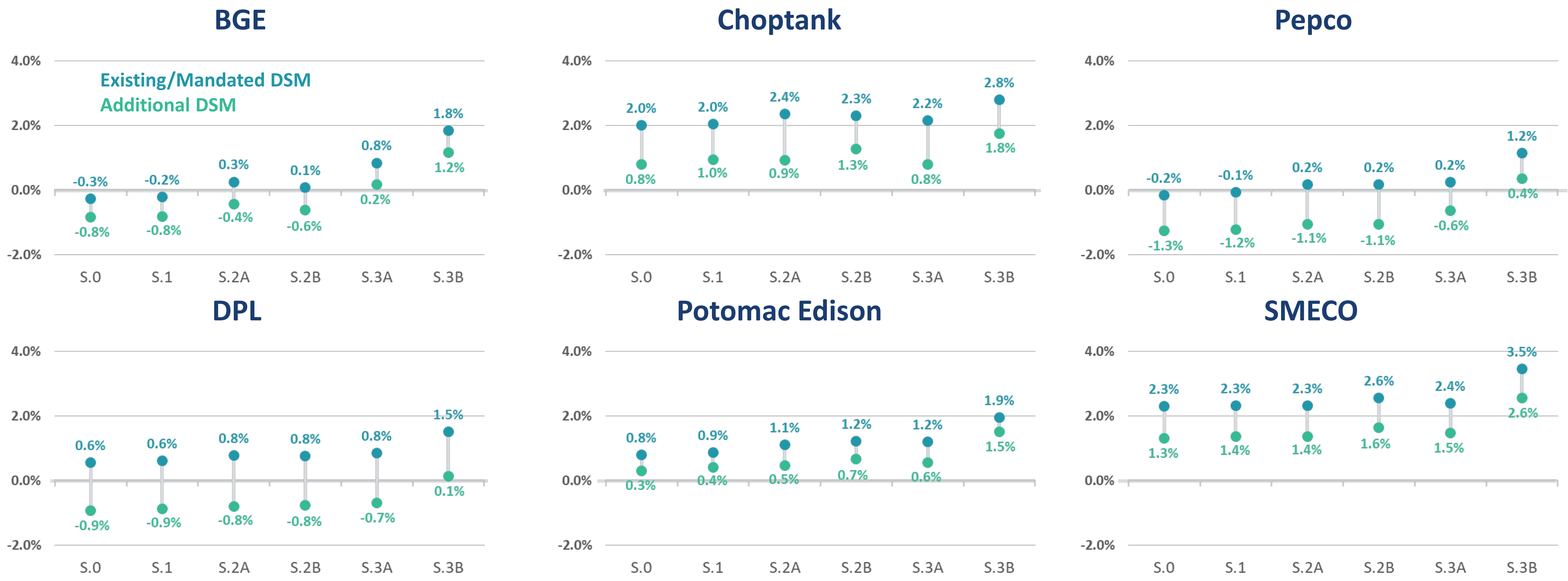
Notes: Y-axis scales differ across charts. 2022 peak load is sourced from 2022 Ten Year Plan or utilities directly. The light bars ("Diff.") are the difference between the Existing/Mandated DSM case and the Additional DSM case, and represent the impact of the Additional DSM programs.

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

Load Growth Results – Existing/Mandated vs. Additional DSM

2022-2031 Compound Annual Peak Load Growth Rate (CAGR) by Scenario and Utility

*With **Existing/Mandated** and **Additional** Demand Side Management*

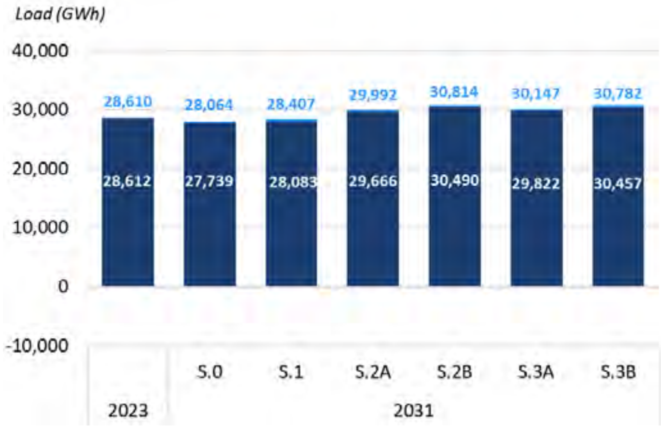


Sales Growth Results – Existing/Mandated vs. Additional DSM

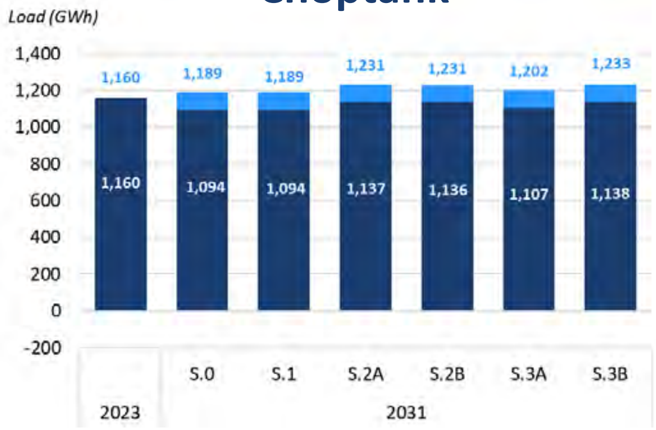
S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

2023-2031 Annual Electricity Consumption by Scenario and Utility

BGE

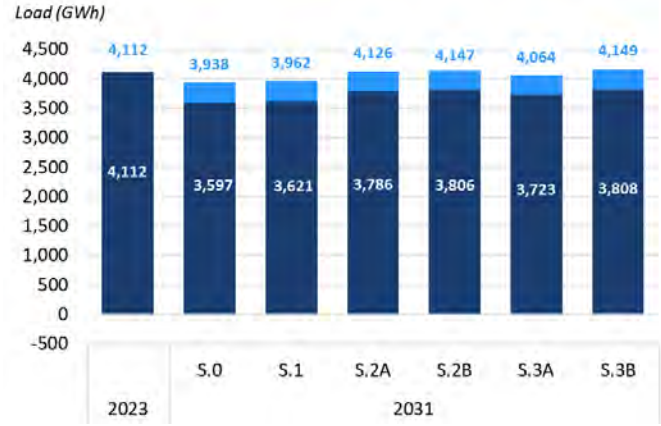


Choptank

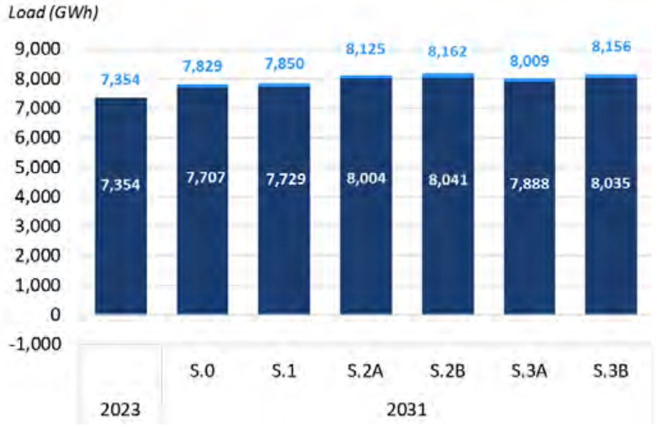


Pepco

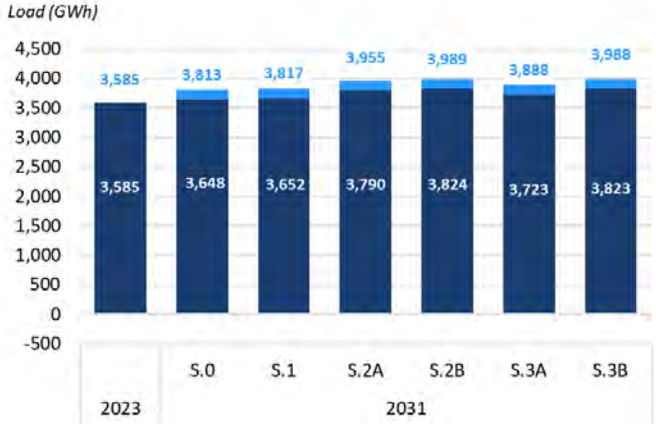
DPL



Potomac Edison



SMECO



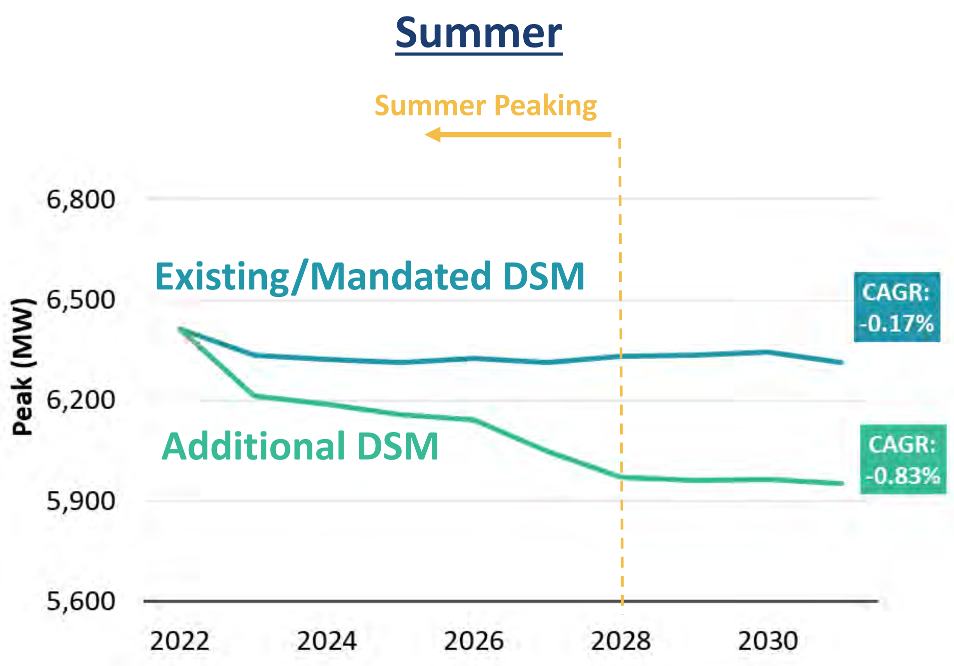
Notes: Vertical axis scale differs across charts.

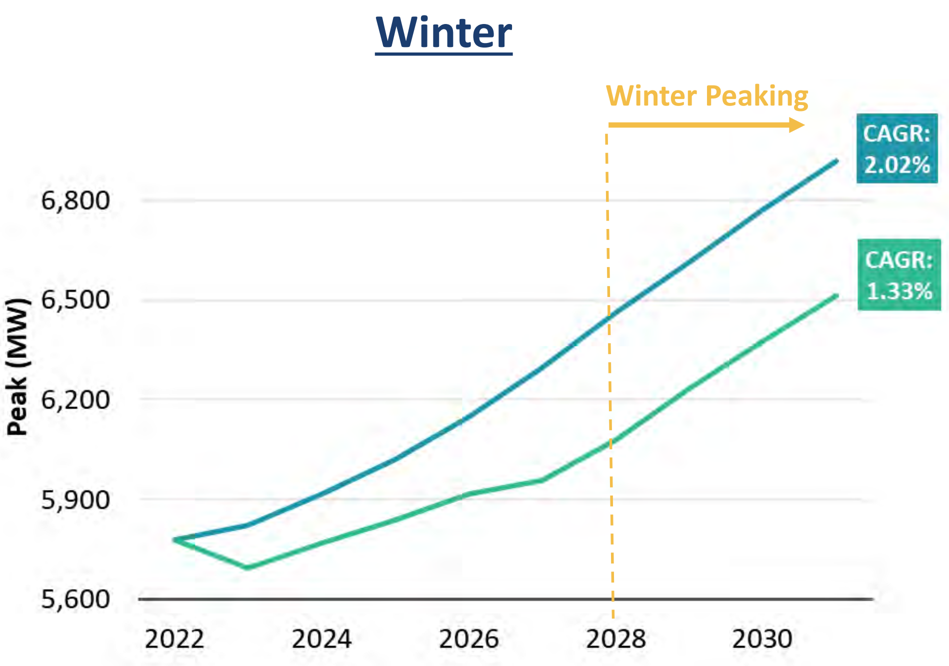
Impact of EE and Load Flexibility – BGE S.3A

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

BGE Summer and Winter Peak Loads with Existing/Mandated and Additional DSM

High Electrification with Best-in-Class Technologies Scenario (S.3A)





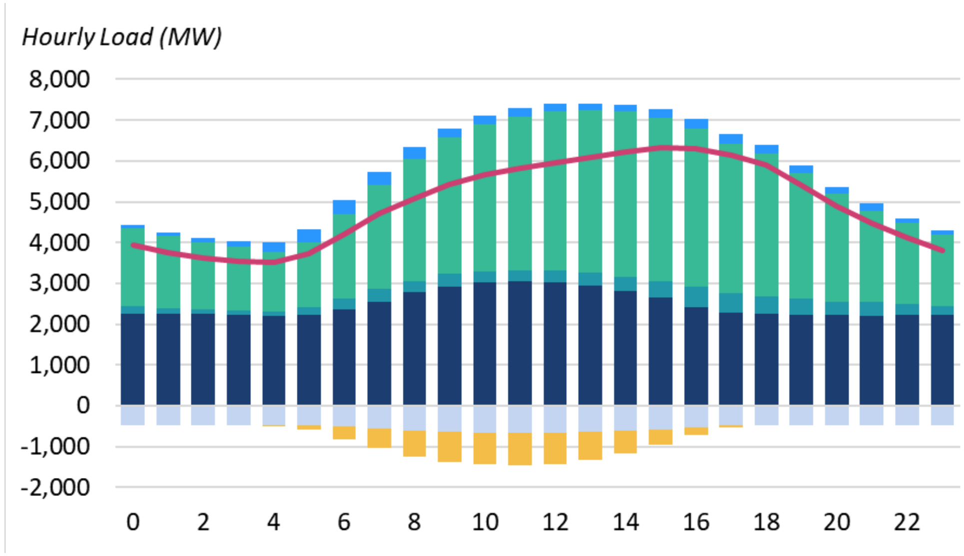
Note: BAU and High scenarios switch from Summer to Winter peaking in 2028

DSM on Summer Peak Day – BGE S.3A

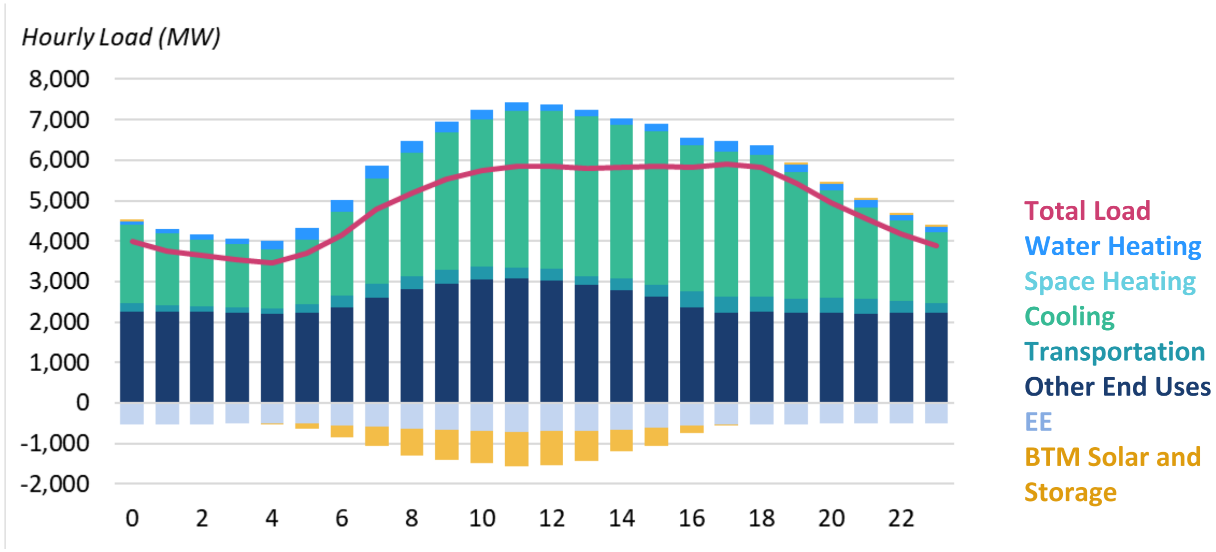
Hourly Load by End Use on 2031 Summer Peak Day, *MW*

Additional DSM Programs flatten load shape relative to Existing/Mandated DSM Programs Case and shifts peak hour

Existing/Mandated DSM Programs



Additional DSM Programs

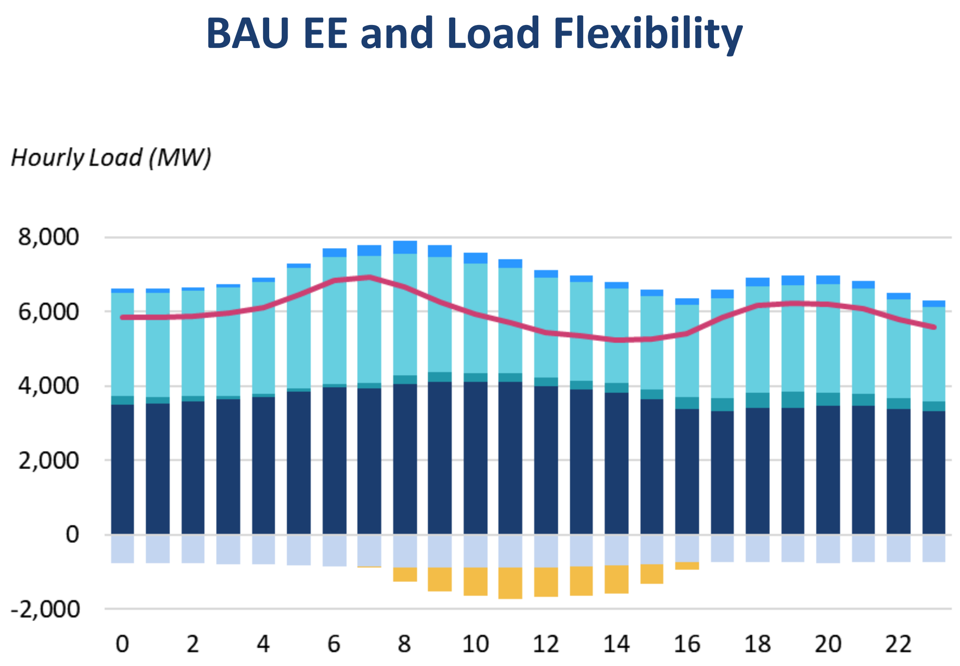


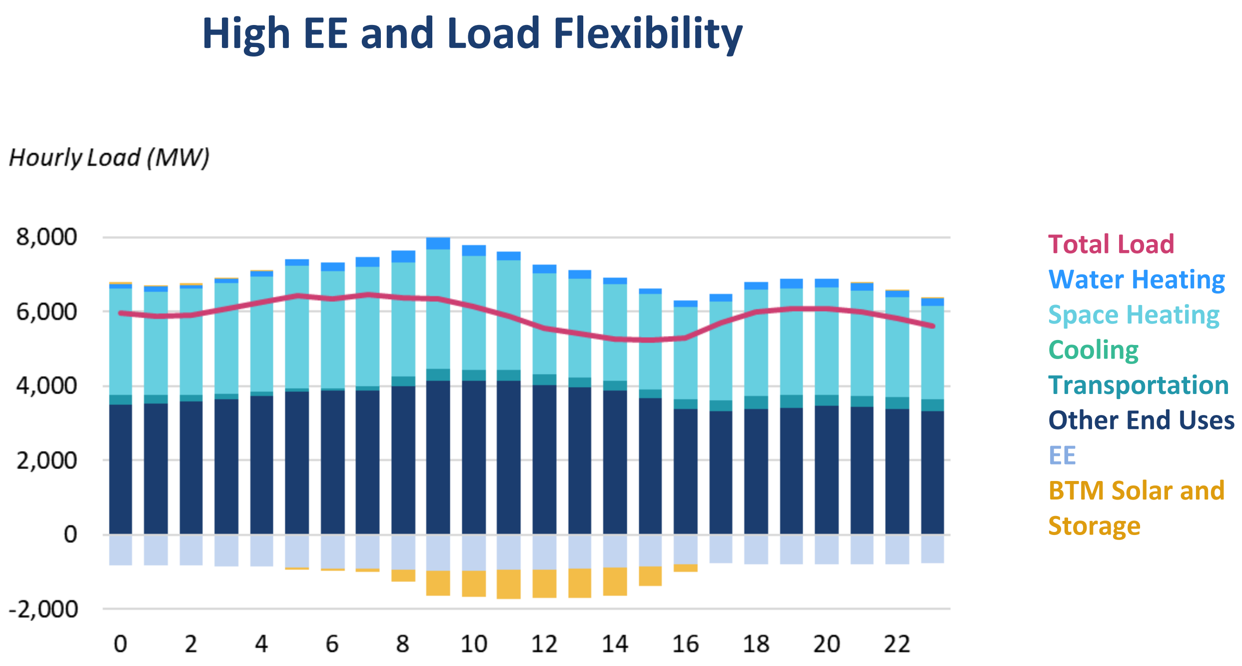
Notes: Load flexibility impacts are reflected within their respective end use (e.g EV managed charging program impacts Transportation load). All hours are hour beginning.

DSM on Winter Peak Day – BGE S.3A

Hourly Load by End Use on 2031 Winter Peak Day, *MW*

Additional DSM Programs flatten load shape relative to Existing/Mandated DSM Programs Case and reduce peak





Notes: Load flexibility impacts are reflected within their respective end use (e.g EV managed charging program impacts Transportation load). All hours are hour beginning.

9 – Conclusion

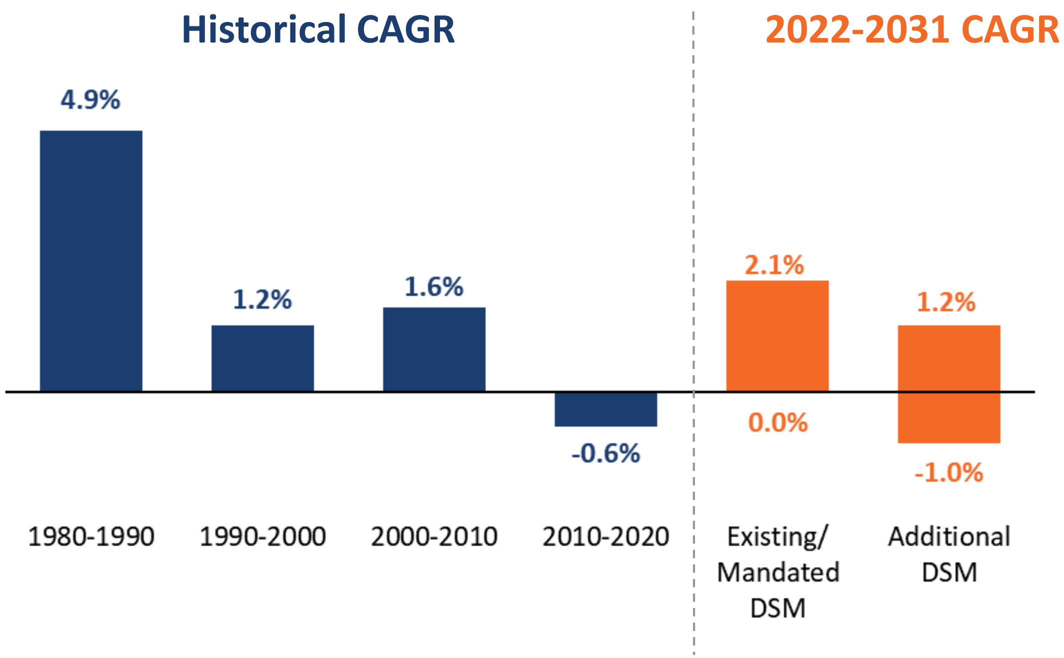
Maryland-Wide Historical Peak Growth Rates

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

Results show that peak load growth through 2031 with high electrification of the building sector will be comparable to or less than the Maryland system has seen over the past 40 years.

- Historically, there was significant load growth in the 1980s of 4.9% per year and more moderate growth of 1.2-1.5% from 1990-2010. Load declined between 2010-2020.
- High Electrification with Legacy Tech (S.3B) with Existing/Mandated DSM would have the highest growth rate of 2.1% per year
  - Additional DSM programs would reduce this to 1.2% per year
- High Electrification with Best-in-Class tech (S.3A) with Existing/Mandated DSM would have a growth rate of 1.1% per year
  - Additional DSM would reduce this to 0.3% per year
- The lower ends of the ranges are the Reference, Low Electrification, and Mid Electrification Scenarios, which do not include a highly electrified building sector

Maryland Historical and Forecasted Growth Rates

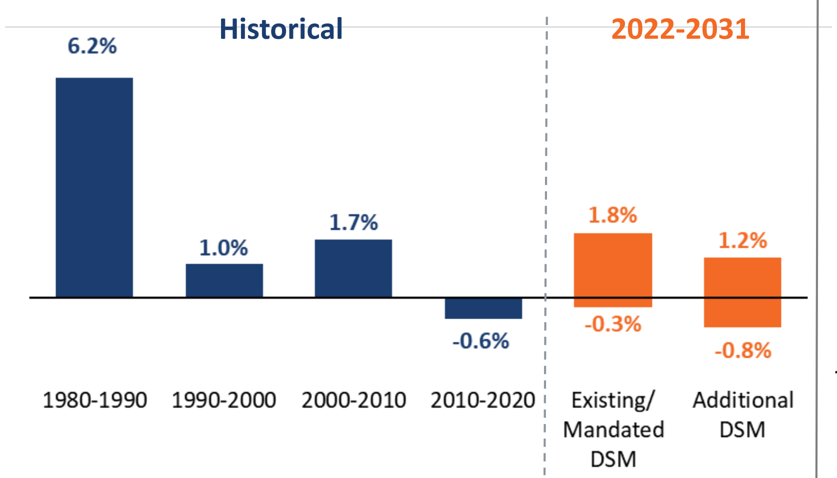


Notes: Historical load growth calculated based on load weighted average for Maryland utility historical peak load. Historical peak load provided by utilities where applicable, otherwise CAGRs from respective PJM LDA historical peaks. Only accounts for in-scope Maryland utilities. Forecasted load growth rates show range of CAGRs for all scenarios modeled.

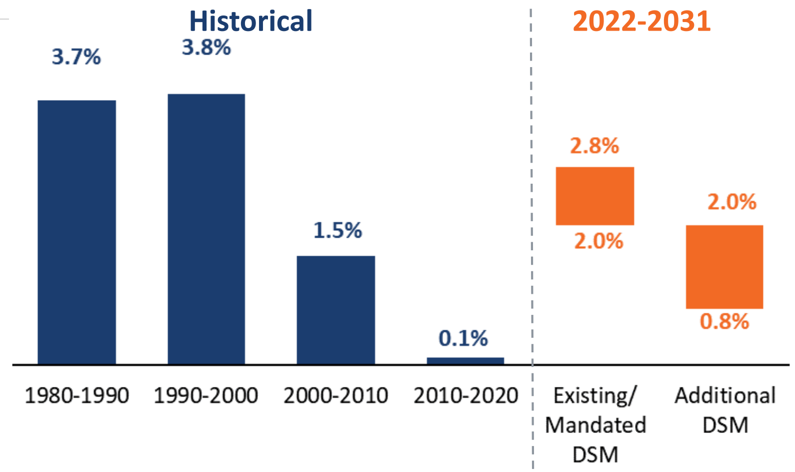
CONCLUSION

Historical Growth Rates by Utility

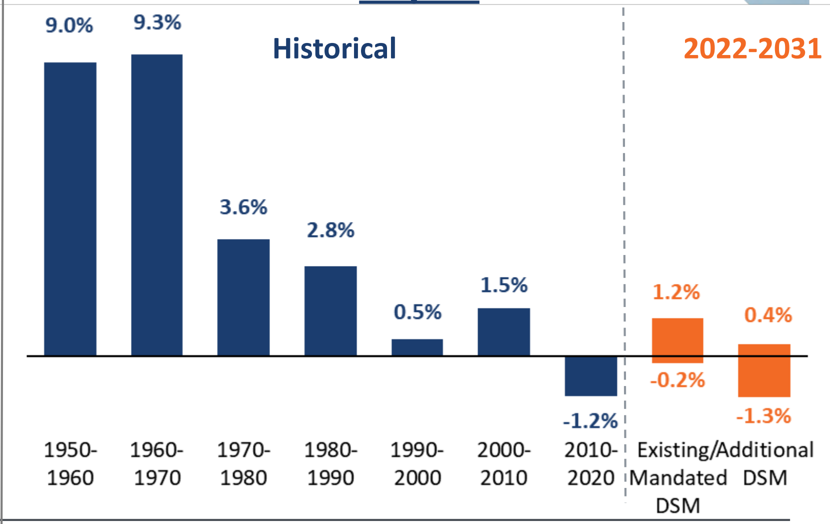
BGE



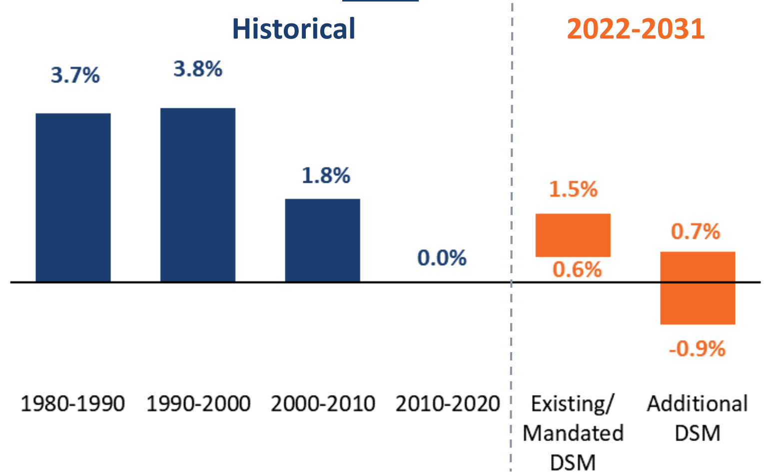
Choptank



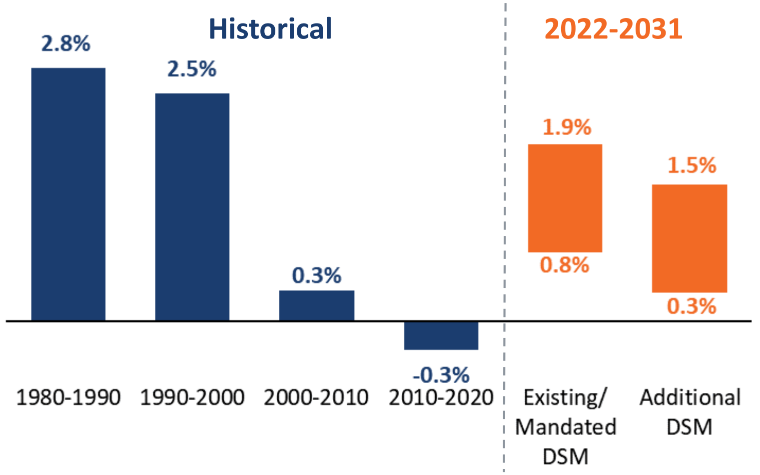
Pepco



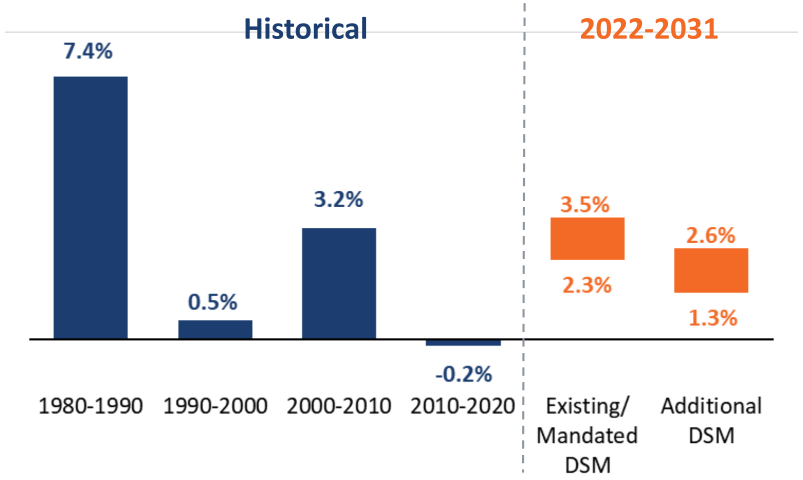
DPL



Potomac Edison



SMECO



Notes: Vertical axis scale differs across charts. Historical peak load provided by utilities where applicable. Otherwise, CAGRs sourced from respective PJM LDAs. Forecasted load growth rates show range of CAGRs for all scenarios.

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

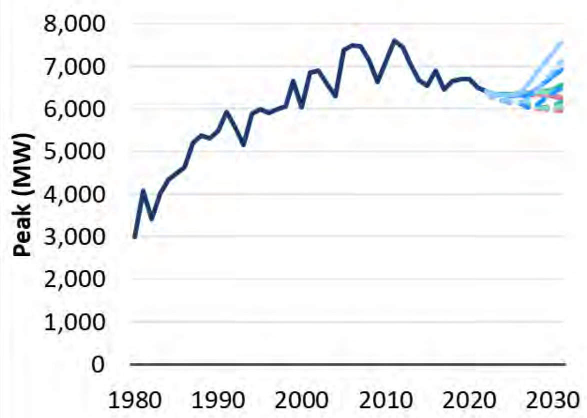
Solid = Existing/Mandated DSM
Dashed = Additional DSM

Historical Growth by Utility

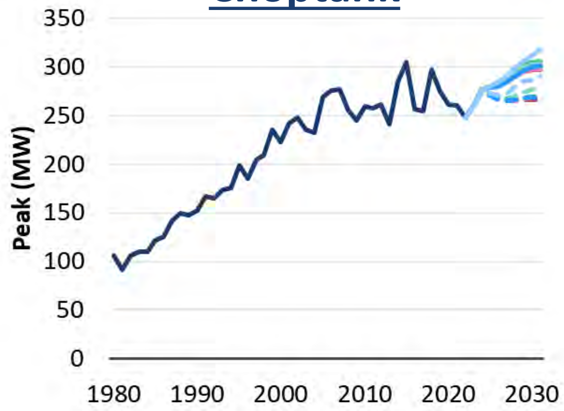
Historical and Projected Peak Loads by Utility

Historical loads are from utility data and/or from PJM load growth data for the utility's load zone

BGE

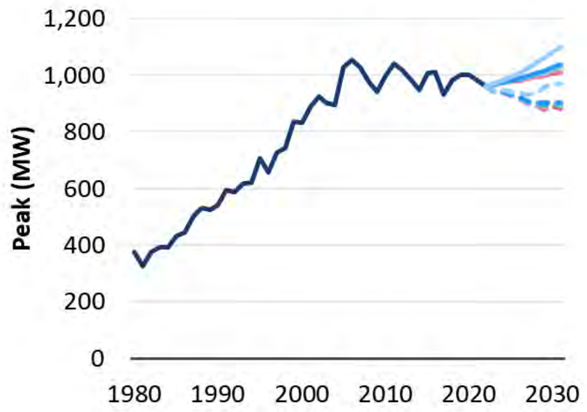


Choptank

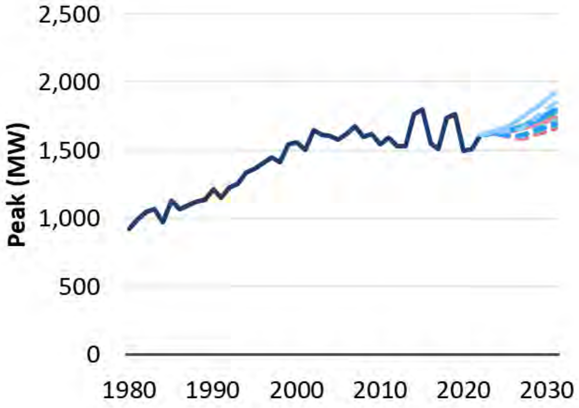


Pepco

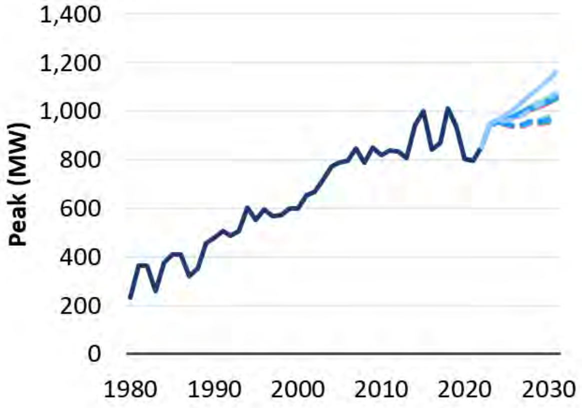
DPL



Potomac Edison



SMECO



Sources for historical load: 1) BGE: PJM load zone data 2) Choptank: Utility data 2010-2022, PJM growth rate for load zone 1980-2010 3) Pepco: Utility growth rate data 1950 – 2022 4) DPL: Utility growth rate data 1999-2022, PJM growth rate for load zone 1980-1999 5) Potomac Edison: Utility data 2009-2022, PJM growth rate for load zone 1980-2009 6) SMECO: Utility data 1993-2022, PJM growth rate for load zone 1980-1993.

S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

Recap of Results for Maryland System

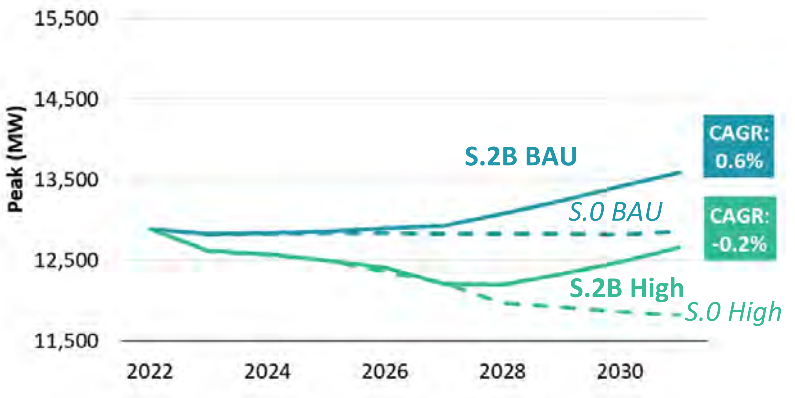
Results show that in the High Electrification Scenarios, the aggregate Maryland system would see 0.6%-2.1% annual growth with Existing/Mandated DSM.

- The High Electrification Scenarios result in direct building heating emissions reductions consistent with MDE's Climate Pathway to meet the 60x31 goal
- The Maryland system, which is currently summer peaking, would switch to winter peaking around 2026-2027
- BGE and Pepco, the largest utilities, see limited load growth because they have significant headroom between the winter and summer peaks and because they forecast limited growth from non-electrification drivers like economic growth
- Pursuing policies to incentivize efficient electrification over legacy technologies (S.3A vs. S.3B) could result in significant mitigation of load growth
- A hybrid approach with fossil backup would also result in electric load mitigation, but would require continued direct emissions from buildings
- High electrification scenarios reduce gas demand from buildings by 31-32% and total gas utility deliveries by about 20%
- Additional demand side management programs could result in significant further mitigation of load growth in every scenario

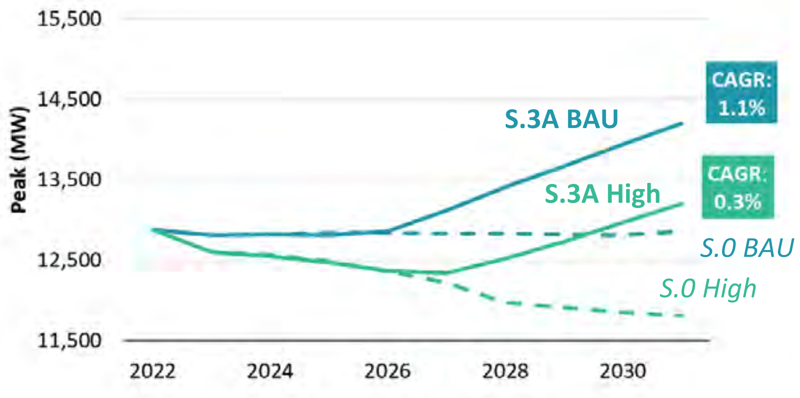
Maryland[1] System Peak Load

*With **Existing/Mandated** and **Additional DSM** Energy Efficiency and Load Flexibility*

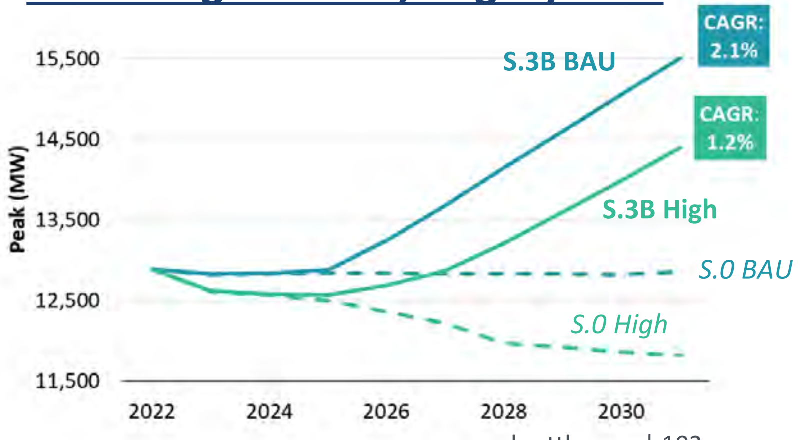
S.2B – Hybrid with Fuel Backup



S.3A – High Elec. w/ Best-in-Class Tech



S.3B – High Elec. w/ Legacy Tech



1 Does not include out-of-scope utilities

Maryland Public Service Commission

Electrification Study Report Q&A

Q. Why did the Commission perform an electrification study?

A. The electrification study was performed in compliance with Sect. 10 of the Climate Solutions Now Act of 2022 (CSNA), which requires the Public Service Commission to complete a general system planning study to assess the capacity of each gas and electric company's distribution systems to successfully serve customers under a managed transition to a highly electrified building sector. The CSNA set Maryland on a course to achieve net zero greenhouse gas (GHG) emissions by 2045, and 60% GHG reduction by 2031 relative to 2006 levels. The Act includes provisions for extensive changes to various sectors including transportation, electricity, buildings, and agriculture. Further, the Act set the following requirements for this study:

- use a projection of average growth in system peak demand between 2021 and 2031 to assess the overall impact on each gas and electric distribution system
- compare future electric distribution system peak and energy demand load growth to historic rates
- consider the impacts of energy efficiency and conservation and electric load flexibility
- consider the capacity of the existing distribution systems and projected electric distribution system improvements and expansions to serve existing electric loads and projected electric load growth
- assess the effects of shifts in seasonal system gas and electric loads

Q. What did the Commission's electrification study conclude?

A. The study modeled electrification scenarios that would result in direct building heating emissions reductions consistent with Maryland's Climate Pathway report. The results indicate that the aggregate Maryland electric systems would see load growth rates in the range of 0.6–2.1% per year through 2031 with high electrification, assuming utility energy efficiency plans consistent with the Climate Solutions Now Act and existing utility demand response plans. This increase in load growth is accompanied by a 31–32% reduction in building sector gas demand by 2031 in high electrification scenarios. The Maryland electric distribution system, which is currently summer peaking, would switch to winter peaking around 2026–2027. Furthermore, additional energy efficiency and load flexibility measures could result in significant mitigation of load growth by 2031 to −0.2–1.2% per year. Historically, there was significant Maryland system load growth in the 1980s of 4.9% per year and more moderate growth of 1.2–1.5% from 1990–2010, while load declined between 2010–2020. These results show that peak load growth through 2031 with high electrification of the building sector will be comparable to or less than the growth rate the Maryland system has seen over the past 40 years.

Q. Why did the Commission only perform an electrification study through 2031?

A. The CSNA requires the Public Service Commission to use a projection of average growth in system peak demand between 2021 and 2031 to assess the overall impact on each gas and electric distribution system. The Maryland's Climate Pathway Report demonstrates how Maryland can meet its ambitious climate goals of 60% reduction of greenhouse gas emissions by 2031 relative to 2006 levels, and attain a net-zero economy by 2045.

Q. Why were grid impacts developed based on system-level load growth results, as opposed to a more granular grid study that identifies local investment needs?

A. The electrification study scope does not require a granular distribution system planning study and therefore, does not identify local investment needs. In addition, this type of granular study would require significantly more time and investment to develop. The electrification study final report is similar to other reports that the Brattle Group has authored in the past where system-level load growth results are intended to provide one reasonable benchmark by which to determine whether the system load growth in a high electrification scenario will be within the range of growth utilities have accommodated in the past.

Utilities will need to develop their own "bottom-up" distribution impact studies to identify which parts of the grid will experience more immediate growth, and develop plans accordingly, including a consideration of non-wires alternatives. It is important to note that, while this electrification study provides a utility system-level view of load growth trajectory under different scenarios, this study is not a substitute for more granular, locational distribution planning studies that could be conducted by the utilities. Through these studies, utilities will be able to plan specific upgrades to the distribution system based on the loading of existing equipment and forecasted customer adoption of various technologies.

Q. What types of considerations are outside of the electrification study scope?

A. The transition to a highly electrified building sector is complex and multifaceted. Each facet merits detailed study during the process of policy development and implementation. This study is intended to inform policymakers regarding one facet of the transition—the impacts on electricity and natural gas demand through 2031. This study does <u>not</u> address several important transition issues, including but not limited to:

- Cost-effectiveness of building electrification;
    - *Note: Each scenario would result in several costs, including equipment installation and maintenance costs borne by building owners and grid investment and demand-side management program costs borne by utilities and utility ratepayers. Each scenario would also create several benefits, including fuel savings, avoided natural gas infrastructure investments, reduced societal impacts of GHG emissions, and reduced health impacts of air pollution. These types of considerations would require significantly more time and investment to evaluate*.
- The technical feasibility and commercial availability of electrification technologies for various types of customers;
- Locational distribution system upgrades that may be needed to support new load and locational non-wire solutions that may defer distribution system upgrades;
- Potential decommissioning of parts of the gas delivery system as customers electrify;
- Regulatory mechanisms to sustainably manage gas utilities as gas throughput declines;
- Environmental justice and equity to ensure that disadvantaged communities are not left behind in the transition.

Q. What does this electrification study mean for the future of electrification in Maryland?

A. The scope of this study was to pursue "what-if" scenarios to provide information for policy makers to make decisions about the future of electrification which could include further incentives to accelerate different types of heat pump adoption, additional load flexibility and energy efficiency measures, and building electrification standards, among other things.

Q. What does this study mean for the future of gas planning and electric distribution planning in Maryland?

A. Successful gas and electric distribution planning depends on gas and electric demand forecasting as a first step. A key question moving forward is how will utilities provide transparency, accommodate stakeholder involvement and build consensus on the assumptions used to develop their investment plans? Electrification pathways affect gas forecasts and gas near-term and long-term plans will also impact electric distribution forecasts. There is currently a docketed case (Case No. 9665) and Commission workgroup established for electric distribution system planning that must consider these questions. There is also a newly docketed case (Case No. 9707) where gas system planning will be considered.

Q. What EmPOWER assumptions were used for the study?

A. In Case No. 9648 for EmPOWER, the utilities filed 2024–2026 Program Proposals. In Order No. 90549, the Commission required the utilities to develop three scenarios that resulted in increasing GHG savings while still meeting the energy efficiency goals required by law:

- 2023 Scenario - Utility required to meet the energy efficiency goals as required by law as cheaply as possible.
- Middle Scenario - Between the 2023 and maximum scenario that reduces GHG above the 2023 scenario but is cognizant of funding constraints. Must meet energy efficiency goals in law.
- Maximum Achievable Scenario - Utility required to meet the energy efficiency goals while trying to meet the potential studies maximum achievable and was intended to include programs and measures that would bring maximum savings when spending is unconstrained.

Energy efficiency assumptions in the electrification study are based on the EmPOWER 2024–2026 program cycle plans filed by utilities in August 2023. The existing/mandated Demand Side Management Programs case assumes utilities achieve the “2023 Scenario” level of energy efficiency from these filed plans, which is based on achievement of minimum statutory requirements.