Mid-Atlantic Long-Term Vision Analysis

Strategies and Costs of Decarbonizing Natural Gas End-Uses

States in the Mid-Atlantic region are aggressively pursuing long-term policies to reduce greenhouse gas (GHG) emissions as they work toward a net-zero carbon-emissions future. Reducing carbon emissions from natural gas end-uses—from building sector space and water heating as well as commercial and industrial uses—has become a key focus of state policy making alongside emission reductions in the transportation and electric sectors. Meeting climate ambitions, while ensuring consumer energy costs remain affordable, will require thoughtful policy and planning. This study focuses on strategies and costs of decarbonizing natural gas end-uses. Optimal decarbonization paths for natural gas include energy efficiency measures along with investments in new renewable and low-carbon energy infrastructure. Prior natural gas decarbonization studies have not adequately considered the full cost impact of energy infrastructure, especially for regions of the U.S. where natural gas dominates the heating market.

1. Key Takeaways

- According to ERM analysis, a Hybrid scenario that uses a combination of energy efficiency, electrification, and low carbon fuels represents a least-cost path to decarbonize the Mid-Atlantic region's natural gas end-uses compared with other paths.
- This study's Hybrid scenario can help mitigate the risks of over-reliance on a single energy system while optimizing use of existing electric and gas infrastructure.
- Employing a portfolio of decarbonization strategies can lower the costs of achieving climate goals and can reduce the risks to achieving them.

2. Background

This study provides an in-depth analysis of system-wide cost impacts for decarbonizing natural gas end-uses in the three states of the US Census Middle Atlantic division (New Jersey, New York, and Pennsylvania).[1] The Long-Term Vision (LTV) analysis's three scenarios—Hybrid, High Fuels, and High Electrification—each achieves emission-reductions of 92% by 2050, using a different mix of decarbonization strategies whose costs vary widely.

Decarbonizing building heat in a cold-weather region poses cost and implementation challenges. Highly efficient electric heating options like air source heat pumps (ASHPs) and ground source heat pumps (GSHPs) can provide significant energy and emissions savings over the whole heating season. At the Mid-Atlantic's coldest temperatures, however, even cold-climate ASHP efficiency declines quickly: they require more electricity to deliver a given amount of heating even as the amount of heating needed increases as outside temperatures drop. Heavy reliance on electric ASHPs as the main form of building heating—as in this study's High Electrification scenario—would cause peak electric demand spikes during the coldest days. As this analysis illustrates, major new electric infrastructure investments would be required to meet this increased winter peak heating demand. In contrast to the need for major new electric grid investment, which would raise the cost to customers of decarbonization, the Mid-Atlantic's existing gas distribution systems already serve that peak demand for heat.

For moderately cold weather regions like the Mid-Atlantic, a more cost-effective path is to use a dual-fuel, or hybrid approach to decarbonize natural gas heating needs. This approach maximizes energy efficiency, deploys ASHPs when they are most efficient, and maintains the gas infrastructure's ability to meet cold weather heating demand. The existing gas infrastructure would deliver decarbonized fuels and provide critical heating capacity for the coldest temperatures. This hybrid approach optimizes decarbonization strategies across both the electric and gas systems and yields cost savings for customers over other decarbonization paths. For policymakers seeking to accelerate the transition to net-zero emissions future, a hybrid approach is more feasible, flexible, and reliable.

Mid-Atlantic Decarbonization Scenarios

ERM developed three decarbonization scenarios, each of which achieves a 92% reduction in GHGs for natural gas end-uses by 2050.

Hybrid: Building energy efficiency, electrification, and decarbonized fuels together reduce GHGs. Most building heating is served with a dual-fuel strategy of ASHPs and gas-fired furnaces with some GSHPs and gas heat pumps (GHPs). ASHPs operate during most of the heating season while heating switches to gas on the coldest days. The gas distribution network meets peak energy demand on those coldest days.

High Fuels: Low-carbon fuels such as renewable natural gas (RNG) and hydrogen blends drive this approach with efficient GHPs serving as the primary building heating strategy. Existing gas distribution networks play a larger role in delivering decarbonized fuels. This scenario includes building energy efficiency but has minimal electrification of current gas end-use.

High Electrification: Most buildings electrify with ASHPS and GSHPs, significantly increasing demand on the region's electric grids. Building energy efficiency helps reduce demand; decarbonized fuels play a minimal role except in industrial applications. Use of gas distribution networks decline heavily as most residential and commercial customers convert from gas to electricity.

These decarbonization scenarios are benchmarked against the **Reference** scenario, which follows a business-as-usual path that implements no new decarbonization measures over the outlook period.

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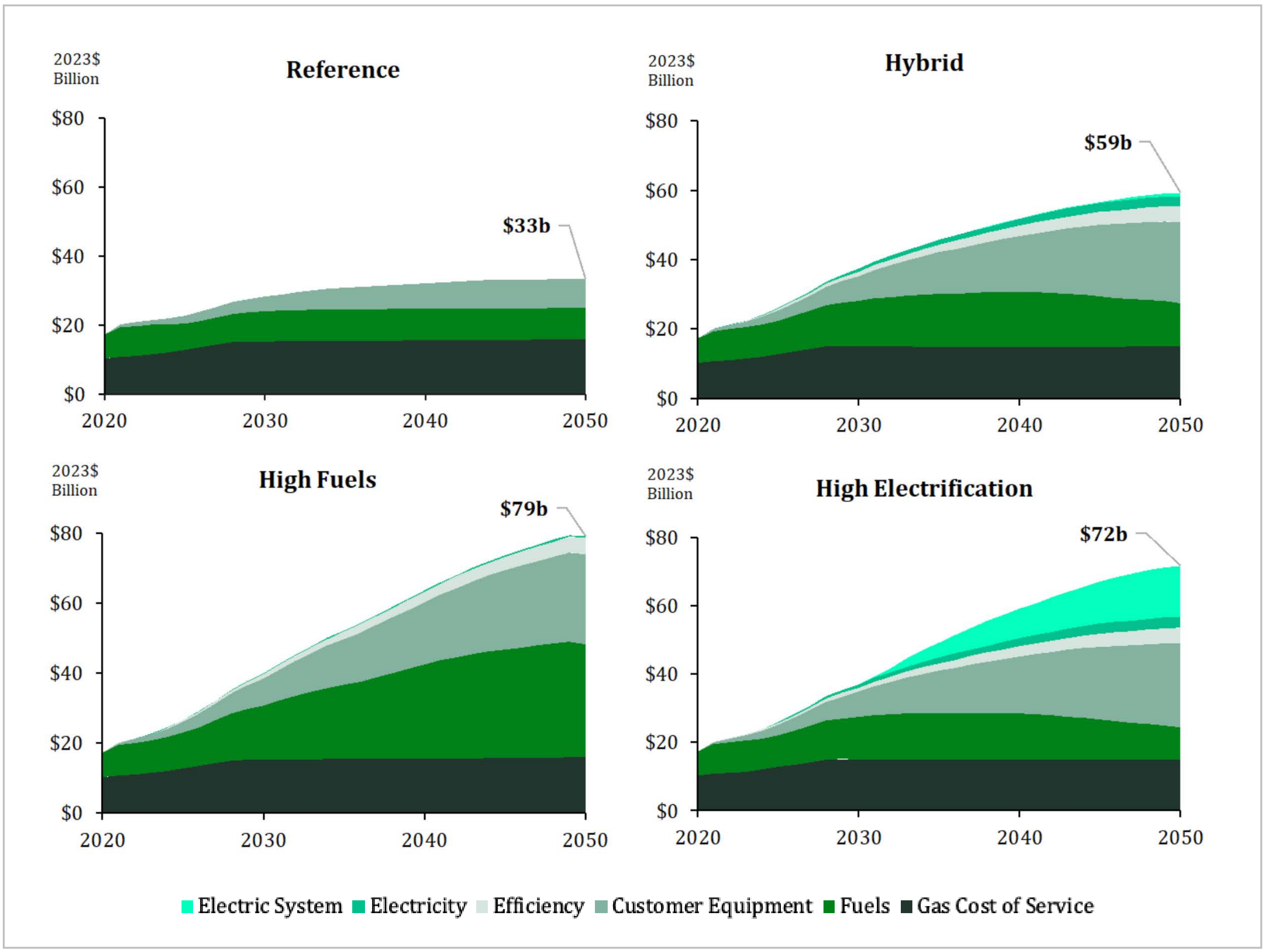
[1] This is the second report of separate regional analyses completed as part of DSI's Long-Term Vision. The first regional analysis on New England can be found here: Long Term Vision Analysis: New England.

3. Summary of Findings

In all three decarbonization scenarios, annualized costs exceed the Reference scenario's $33 billion (see 2050 Annual Costs by Scenario below).[2] The lowest cost scenario, Hybrid, projects 78% higher annual costs ($59 billion) than the Reference scenario by 2050. The High Fuels and High Electrification scenarios project annual costs of 137% and 114% higher than Reference ($79 billion and $72 billion), respectively. The cost of gas service is slightly lower in the Hybrid and High Electrification scenarios because the study assumes that gas systems are maintained for safety and reliability but does not assume capital and operational expenses from gas customer growth or system expansion. The Reference and the High Fuels scenarios assume the same amount of gas customer growth.

Figure 1: Total Annualized Costs by Scenario



[1] These figures represent annualized system-wide energy costs, most of which we assume would pass to customers in their energy bills. All costs are presented in real, 2023 dollars.

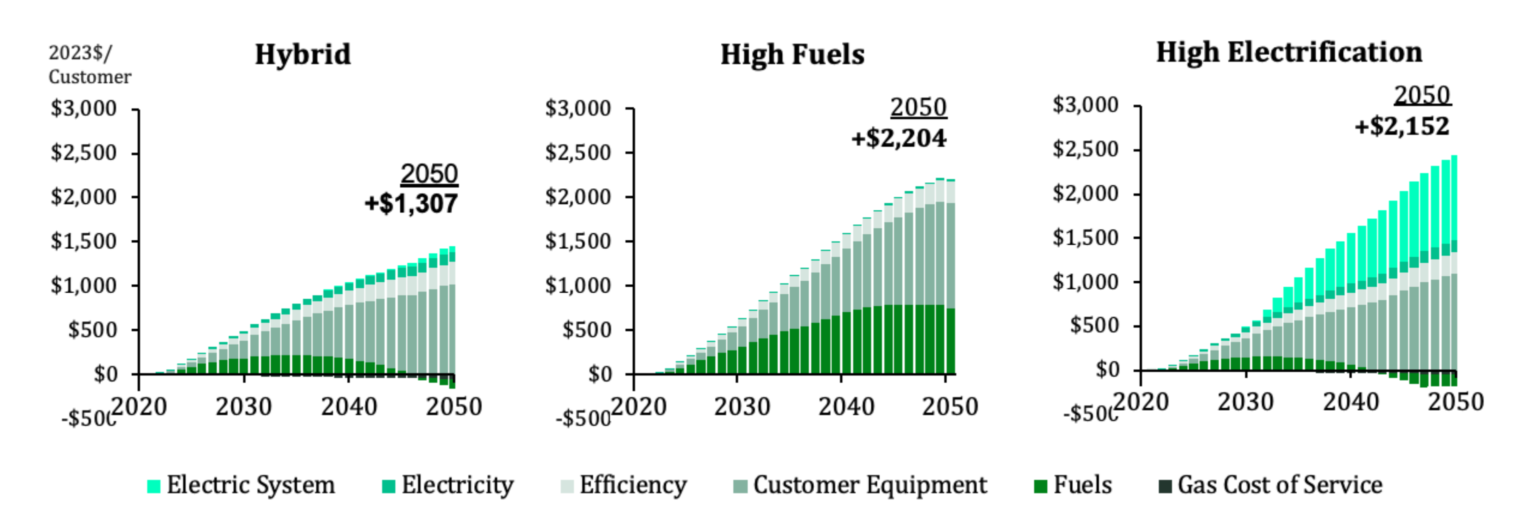
Costs in the High Fuels scenario are driven mainly by the demand for low-carbon fuels such as renewable natural gas (RNG), green hydrogen and methanated green hydrogen . This scenario strains the projected available supply, particularly of RNG, and relies on more expensive sources of low-carbon fuels to meet demand.

The largest differentiating cost in the High Electrification scenario comes from the investment required to meet the winter peak heating demand currently served by the existing natural gas system. Fully replacing most natural gas heating with electric technologies would create an added peak demand for New York (NYISO grid) of about 15 gigawatts (GW) and about 24 GW for New Jersey and Pennsylvania (PJM grid) by 2050. As noted above, the reduced efficiency of ASHPs at the coldest of the region's temperatures, when heating demand is highest, drives the need for extensive build-out of electric infrastructure investment. This cost grows rapidly as the regional grids shift to a winter-peaking system from a summer-peaking one after 2030. The cost of the added electric infrastructure just for this winter peaking demand, depicted by the bright green in the chart above, is estimated to be $15 billion annually by 2050. The investment includes both the clean generation capacity to meet the demand and the transmission and distribution capacity to deliver it to customers.

The Hybrid scenario avoids the highest cost elements of the High Fuels and High Electrification scenarios by balancing energy and peak demand across the gas and electric systems. In this scenario, ASHPs still provide the majority of heating needs, yielding energy savings and emissions reductions. Using decarbonized fuels during the coldest temperatures would delay the shift of the electric grid to winter peaking by a decade or more. This hybrid approach would also reduce the incremental electric peak demand in 2050 to zero in New York and 5 GW in New Jersey and Pennsylvania. This scenario moderates the high cost of fuel in the High Fuel scenario and high electric-system (peak) costs of the High Electrification scenario. Lower fuel demand in the hybrid scenario allows the lowest cost resources to serve that demand. This optimization of energy consumption and energy infrastructure leads to the scenario's lower costs.

When total scenario costs are scaled to a single residential customer, the decarbonization scenarios each reflect significant incremental costs over the Reference scenario (see Figure 2 below). In 2050, an average residential customer's share of the Reference scenario costs is projected to be $1,656 per year, which includes annualized equipment costs, fuel costs, and gas cost of service. The Hybrid scenario would add $1,307 in net incremental costs, a 79% increase over Reference. In High Fuels and High Electrification, incremental costs in 2050 reach $2,204 and $2,152 annually per customer for increases of 133% and 130%, respectively, over the Reference scenario.

Figure 2: Indicative Share of Incremental Costs Per Average Residential Customer



Notes on Incremental Share of Costs for Residential Customers: *The above charts show the estimated share of total annualized costs over the Reference scenario for an average residential customer. For each of the cost categories, the amounts depicted represent the residential share of incremental costs by category divided by the number of residential gas and converted customers in a given year. These charts are designed to show the scale of costs accounted for in the study relative to an average residential customer, but they are not meant to represent bills or rates. While many of these costs would be likely borne by individual customers either directly (e.g., for customer equipment) or through energy bills, the costs identified here would flow to customers in a range of ways not considered in this analysis. The totals shown in the charts (+$950 for Hybrid, +$1,800 for High Fuels, and +$1,780 for High Electrification) are net incremental costs: in both the Hybrid and High Electrification scenarios, savings for Fuels and Gas Cost of Service appear as negative numbers in later years, and these reduce the amount depicted at the top of the bars.*

4. Policy Considerations

Achieving significant reductions in GHG emissions will require economy-wide transformations for all energy providers and customers. Providing building heat at the coldest times of the year will be one of the critical challenges to decarbonizing the Mid-Atlantic's energy supply. The strong climate legislation in both New York and New Jersey has driven initial policy efforts in those states toward electrification of the building sector in conjunction with rapid decarbonization of the electric grid. As this analysis indicates, full consideration of all energy requirements including the costs and limitations of decarbonization strategies will be essential to making informed policy decisions that prioritize consumer affordability, energy reliability and safety.

In the Mid-Atlantic, as in other regions, policy and regulatory support will be required to establish a framework for a just, affordable, reliable, and successful energy transition. The following are recommendations to help guide policymaking:

- **Encourage reduction in overall energy demand:** no-regrets actions that incentivize building efficiency such as weatherization and conversion to high-efficiency end-use appliances is a fundamental, cost-effective strategy for any decarbonization path.
- **Understand changes to the electric grid from winter peak energy demand:** increasing peak electric demand from building heat electrification without significant investment in supply side resources and electric transmission and distribution infrastructure may pose energy reliability challenges over the long-term. (These challenges could be compounded by new electric demand from transportation electrification and from data centers.)
- **A Hybrid or dual-fuel strategy may offer emissions and costs savings:** managing winter peak heating demand through a combination of electric ASHPs and gas, along with GSHPs, can minimize energy demand on both systems. This strategy can also mitigate the risks of over-reliance on a single energy system and may have a more feasible customer-adoption path.
- **Pursue low-carbon gaseous fuels (RNG and hydrogen blends):** these can be an effective, scalable strategy for hard-to-electrify end-uses like winter peak heating demand and industrial processes.
- **Develop integrated natural gas and electric regulatory frameworks:** these can encourage the cooperation of gas and electric systems to balance energy demands, integrate demand planning between gas and electric systems, strategically decommission outdated infrastructure, and deploy new technologies.

5. About DSI and the Long-Term Vision Analysis

The Downstream Natural Gas Initiative (DSI) is a group of leading natural gas utilities across North America collaborating to build a shared vision for the role of utilities and the gas distribution network in the transition to a low-carbon future. DSI members, in collaboration with ERM, conducted this LTV analysis to address cost considerations and implications for a range of decarbonization strategies. All decarbonization strategies achieve net zero emissions by 2050.

This LTV analysis is the second report of separate regional analyses. To view the first regional analysis, New England: https://www.erm.com/coalitions/downstream-natural-gas-initiative/

For more information, contact:

Brian Jones
Partner, ERM
Brian.Jones@erm.com

James P. Saeger, CFA
Principal Technical Consultant, ERM
James.Saeger@erm.com