Addendum: BGE Integrated Decarbonization Strategy

Inflation Reduction Act Update

July 2023

Energy+Environmental Economics

Contents

1 Introduction

On August 16, 2022, President Biden signed the Inflation Reduction Act (IRA). The IRA incorporates several programs and provisions that support decarbonization across most sectors of the economy. In October of 2022, E3 released a report titled *BGE Integrated Decarbonization Strategy*. That report considered alternative pathways for BGE to support achievement of net-zero GHG emissions within its service territory and the state of Maryland. Given that the bulk of the analysis underpinning that report was completed before the passage of the IRA, the impacts of that legislation were discussed qualitatively in the report.

This addendum to the *BGE Integrated Decarbonization Strategy* ("E3's 2022 report") reflects updated E3 analysis to quantify the impacts of the IRA, namely incentives that support clean electric generation, hydrogen, and customer adoption of electrification technologies. A key conclusion of E3's 2022 report is that integrated strategies that leverage BGE's electric and gas infrastructure are lower cost and have a lower level of challenge relative to an electric-only approach. The purpose of this addendum is to explore whether that conclusion holds when considering the impact of the IRA. To capture those impacts, this addendum reflects new analysis, including modeling of the impact of the IRA across the PJM market in the E3 RESOLVE capacity expansion model.

Based on this updated analysis, described in detail below, E3 has reached the following conclusions about the impact of IRA in the BGE territory, relative to E3's 2022 report:

1. **The IRA Will Reduce GHG Emissions in Maryland 40% by 2045.** The IRA supports the state of Maryland and BGE in accelerating progress towards decarbonization goals primarily through 1) reducing emissions in the electric sector and 2) by accelerating transportation electrification.

2. **The IRA Supports Decarbonization of Electric Generation and Supports Deployment of Technologies that Can Reduce the Challenge of Serving a Winter Peaking PJM System.** In the near-term, the IRA supports more rapid deployment of technologies like wind, solar and storage, as well as more rapid retirements of coal generation. Longer-term, the IRA provides support for technologies like green hydrogen or carbon capture that support achievement of a reliable winter-peaking PJM system.

3. **Customer Electric Rate Impacts from IRA are Similar to Pre-IRA work**. The electric sector cost reduction impact of the IRA was more muted than E3 had expected. IRA cost savings are offset by modeling refinements that better reflect the cost of meeting winter heating loads in PJM. In addition, the IRA does not change the delivery rate impacts of net-zero scenarios for BGE.

4. **Customer Gas Rates are Incrementally Lower.** The IRA reduces the cost of hydrogen and synthetic gas via the 45V hydrogen production tax credit (PTC). However, most usage of those fuels occurs after the tax credit expires, so impacts on rates are small. The IRA methane fee has small impacts on the cost of natural gas.

5. **Overall Customer Affordability is Improved by the IRA.** Scenarios are somewhat more affordable for customers. Key drivers include equipment/ vehicle subsidies and lower gas rates.

6. **Total Incremental Costs to BGE's Customers and the State of Maryland are Reduced by the IRA.** The incremental economy-wide costs of net-zero scenarios are lower because of the IRA. IRA incentives spur electric sector decarbonization and passenger vehicle electrification under business-as-usual. As a result, less incremental funding is needed to achieve net-zero from BGE, its customers and the state of Maryland.

Based on those findings, the conclusions from the *BGE Integrated Decarbonization Strategy* report are largely unchanged. Key takeaways include:

- **There are multiple viable paths to decarbonization**, but any future that meets net zero will require significant transformations and investments across the economy and a role for electrification in buildings and transportation. The IRA provides critically needed support for transportation and building electrification and clean electricity generation that reduces the emissions gap to net-zero.

- **Pathways that rely on an integrated energy system carry a lower overall cost and level of challenge relative to those that rely more exclusively on electrification or renewable gases.** While the inclusion of IRA incentives has decreased the cumulative incremental total energy system costs of each pathway, the Hybrid scenario and Diverse scenarios are still lower cost.

- **Consumers are central to the transformations required to achieve net-zero** and achieving scale will require developing solutions that are affordable and work for customers. Incentives provided by the IRA will increase the baseline level of electrification in the reference scenario, particularly within the transportation sector. However, all mitigation scenarios require higher levels of electrification, so meeting a net zero target will require further investment and greater incentives.

- **Regulatory and policy support will be necessary to both manage the challenges associated with decarbonization and capture new opportunities**. Although the IRA will provide support and incentives at the federal level, additional regulatory and policy support will be needed. This could include, but is not limited to, enabling BGE and its customers to support the state's decarbonization ambitions to manage the cost impacts of implementing decarbonization, supporting customer adoption of electrification technologies, and implementing non-pipe alternatives projects.

- **BGE has a critical role in enabling decarbonization in Maryland.** BGE is Maryland's largest utility, and could facilitate the scaling of decarbonization technologies including, but not limited to, strategic electrification, networked geothermal, and green hydrogen production and delivery. Regardless of scenario, BGE's infrastructure will deliver most of the energy utilized in its service territory over the coming decades, so the company's role in building and maintaining safe, reliable and affordable energy delivery systems will continue to be critically important to achieving Maryland's climate goals.

2 Inflation Reduction Act Updates

2.1 Summary of Model Updates

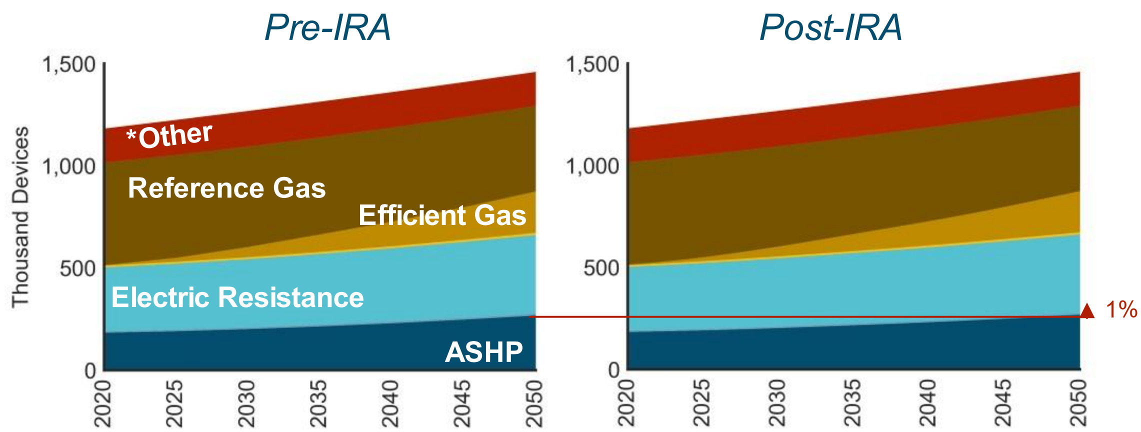
E3 updated certain modeling methodologies and assumptions across all scenarios relative to our 2022 analysis to reflect the Inflation Reduction Action. These adjustments impact costs and rates of adoption of various decarbonization technologies. Specifically, E3 included IRA-related incentives and increased adoption for residential heat pumps, EV incentives for both passenger and commercial vehicles, industry carbon capture and sequestration (CCS) incentives, direct air capture (DAC) incentives, methane fee impacts on natural gas prices, hydrogen and biofuels production incentives, and many impacts on the electric sector including: investment tax credit (ITC) and production tax credit (PTC) extensions, hydrogen fuel cost updates reflective of incentives, CCS incentives.

A key methodological update is that this analysis incorporates new modeling of the PJM energy market in the E3 RESOLVE capacity expansion model. Additional discussion of that modeling can be found in Appendix 1.

2.2 Residential Heat Pump Adoption

E3 included the Energy Efficient Home Improvement Tax Credit (25C), which allows for a heat pump credit worth the lesser of 30% capital costs and $2,000 per home per year and $1,200 (combined) for insulation and panel upgrades. We also included the Residential Energy Efficient Home Credit (Rebate), though we assume the market potential of this program is limited given its $4.5B national budget. This rebate is capped at $14,000 per home (80%-150% median income gets 50% of rebate amounts), with up to $4,000 or $8,000 per heat pump for low- or moderate-income households, respectively, and additional funding for weatherization or electrical upgrades. For the Reference scenario, we found that the IRA results in a very small increase (1%) in residential air source heat hump (ASHP) adoption because the tax credits are not large enough to bring heat pumps to cost parity with counterfactual technologies. The impact of IRA heat pump tax credits on customer affordability is discussed in Section 3.5 of this addendum.

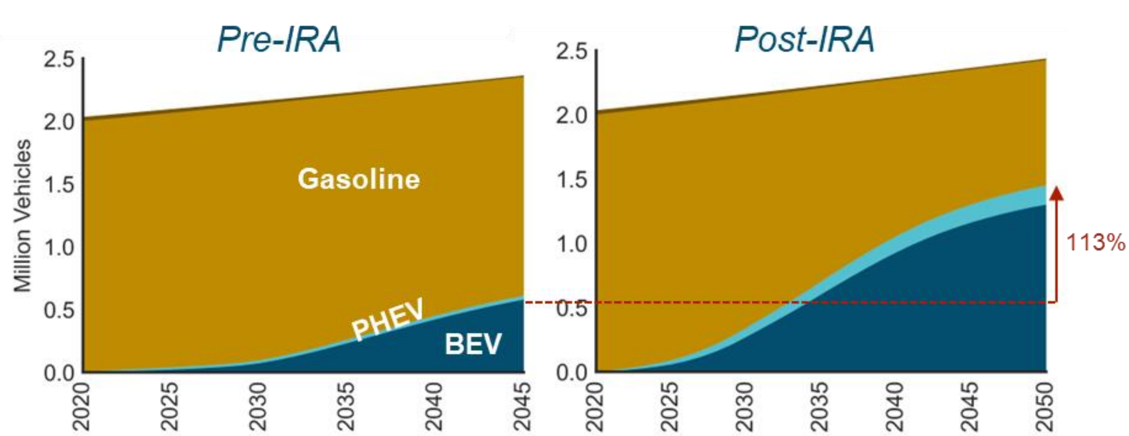
Figure 1: Maryland Reference Residential Space Heating Stock Pre- and Post-IRA inclusion



2.3 EV Incentives for Passenger and Commercial Vehicles

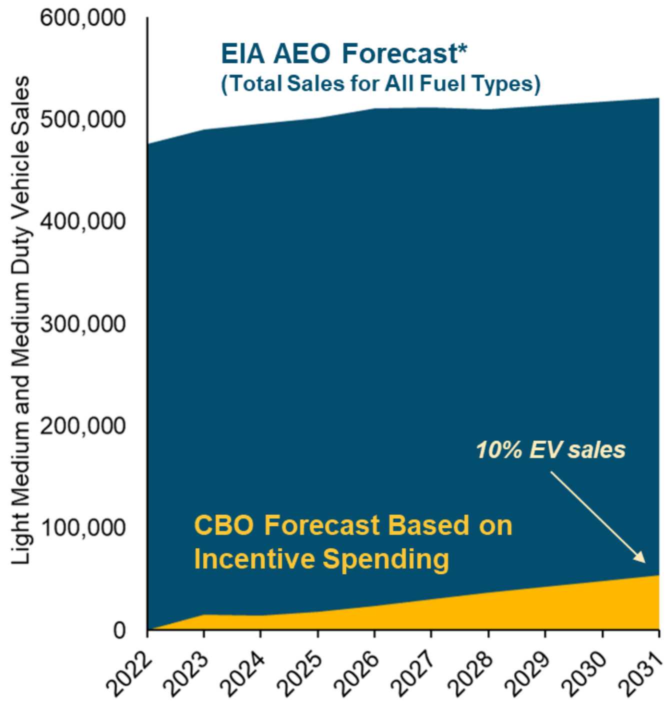
The Clean Vehicle Credit for passenger EVs removes the pre-IRA manufacturer cap eligibility based on sales (making more models eligible), adds requirements for North American assembly and battery critical minerals and component supply chains (making fewer models eligible in the near term until supply chains adjust), and adds new thresholds for vehicle MSRP and customer income (making fewer models and customers eligible). Internal modeling by Exelon for EV adoption across service territories indicates that even a partial tax Clean Vehicle Credit of $3,750/vehicle will drive high sales of EVs, and external forecasts such as BNEF's Electric Vehicle Outlook indicate EV sales reach >50% sales of all passenger vehicle sales by 2030. This tax credit has a significant impact on battery electric vehicle (BEV) adoption in BGE's service territory.

Figure 2: Maryland Reference LDV Stock Pre- and Post-IRA inclusion based on Exelon and E3 analysis



The Qualified Commercial Clean Vehicles tax credit covers the incremental cost of an EV above a diesel vehicle or 30% of the EV purchase price, whichever is less, up to a maximum of $40k (or $7.5k if vehicle weight under 14,000 lbs).[1] For commercial vehicles, Congressional Budget Office (CBO) estimates for the amount of funds that would be allocated as part of the Qualified Commercial Clean Vehicles incentive were used to estimate the increase in EV sales shares.

Figure 3: National Light-Medium and Medium Duty Vehicle Sales Forecast

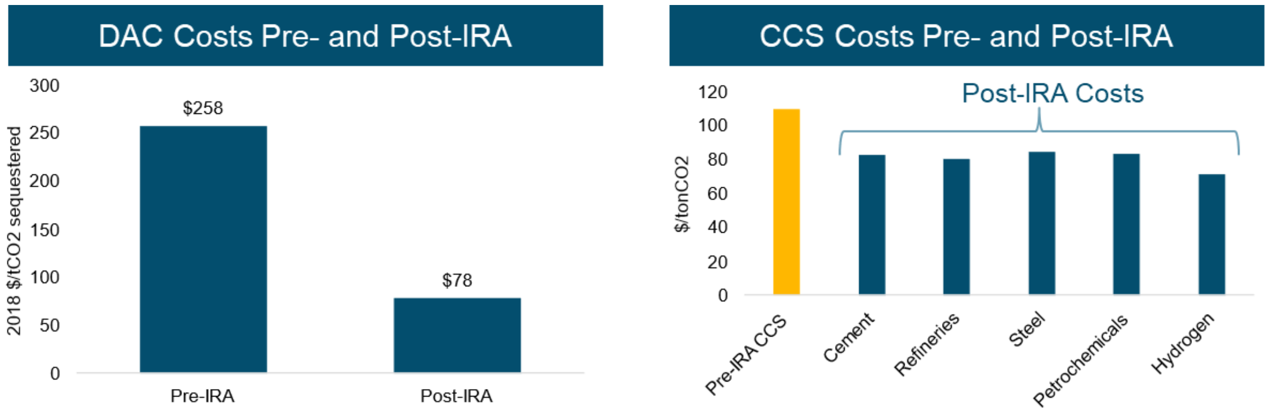


2.4 CCS and DAC Incentives

The IRA increases the Section 45Q tax credit for industrial CO2 captured and geologically sequestered from $50/ton to $85/ton for point source emissions, and $180/ton for DAC. In the coming decade, E3 expects these tax credits to have a significant impact on spurring carbon capture projects. Long-term, however, their impact on the total cost of BGE's net-zero scenarios is likely to be modest, unless the tax credits are extended beyond 2033. DAC is assumed to only emerge at scale in later model years under the BGE scenarios.

[1] $40k cap favors purchasing smaller MDVs over HDVs to maximize credit coverage of total vehicle cost

Figure 4: Pre- and Post-IRA DAC and CCS costs



2.5 Methane Fee Impacts on Natural Gas Price

The Methane Emissions Reduction Program included in the IRA imposes a fee on methane emissions above a certain threshold from upstream and midstream oil & gas facilities based on the following schedule: $900/tCH4 in 2024 ($36/tCO2e), $1,200/tCH4 in 2025 ($48/tCO2e), $1,600/tCH4 in 2026 and beyond ($60/tCO2e). Starting in model year 2024, E3 added a set amount to natural gas prices on a $/MMBtu basis. The adder was calculated based on an estimated total annual amount of money that could be collected as part of the methane fee created as part of the IRA, and the amount of dry gas production that occurred in the US in 2019; the projected rate increases between 2024 and 2026, and is held constant thereafter. E3 expects the impacts of the methane fee to be modest, in part because many natural gas producers fall below the production threshold at which the fee is applied.

Figure 5: Natural Gas Price Impact of Methane Fee

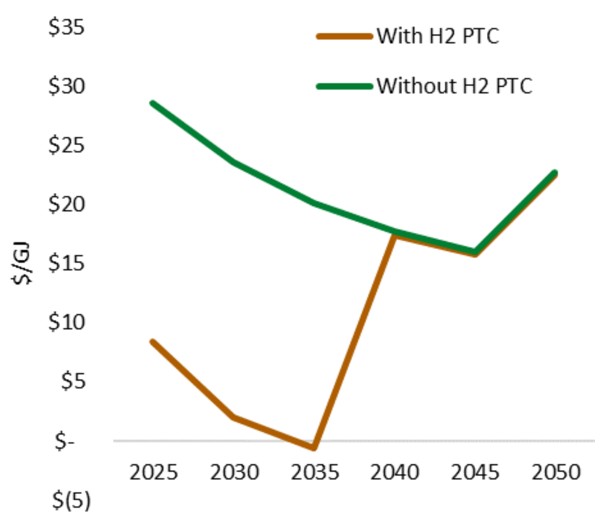
Category	$900/tCH4 (2024)	$1200/tCH4 (2025)	$1500/tCH4 (2026+)
2019 Emissions Subject to Fee (MMT CH4)	1.71	1.71	1.71
Total Potential Fee Amount (Million 2022$)	$1,541	$2,054	$2,568
2019 US Natural Gas Production (TBtu)	34,814	34,814	34,814
Total Potential CH4 Fee / Total Natural Gas Production (2022$/MMBtu)	**$0.04**	**$0.06**	**$0.07**

2.6 Hydrogen and Biofuels Production Incentives

In E3's 2022 Report, hydrogen and biofuels were used across the buildings, transportation, industry and electric generation sectors. The IRA 45V Production Tax Credit provides up to $3/kg (~$20/MMBTU) for low-GHG hydrogen projects. Relative to pre-IRA costs, this could make hydrogen competitive with natural gas on cost over the coming decade. H2 is an input to the production of Synthetic Natural Gas (SNG). As a result, the H2 PTC could make SNG lower cost as well.[2] Given those prices, infrastructure deployment, rather than price, may be a more near-term barrier to hydrogen deployment and utilization. E3 cautions that H2 markets are in early stages with the PTC. While the fundamentals suggest prices could fall towards $0/MMBtu, such an outcome has not yet been observed in practice.

E3 incorporated the impacts of these tax credits on the cost of H2 and increased the Reference scenario H2 demand in Maryland according to a cost-effectiveness screen and the state's natural gas consumption. Note that hydrogen fuel costs are impacted directly by the 45V PTC, but that renewable energy incentives in the IRA also impact the final delivered cost beyond this through reducing the cost of energy needed by electrolyzers to produce H2.

Figure 6: Impact of 45V PTC on Delivered Hydrogen Costs



In addition to the H2 PTC, E3 incorporated the extension of IRA incentives for renewable natural gas, biodiesel, renewable diesel, and sustainable aviation fuel in this update.

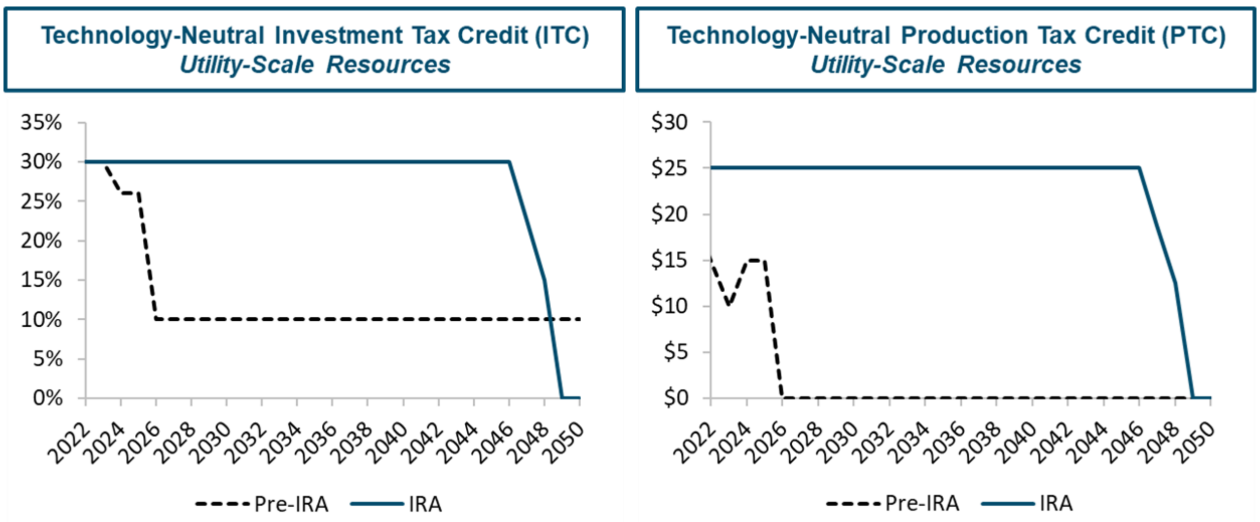
2.7 Electric Sector Incentives

The IRA extends tax credits for renewables until the early 2030s at a minimum; allows for PTCs to be applied to a broad range of technologies including solar (solar can now choose between ITC or PTC); allows for credits to be higher for resources depending on their location and whether they use domestic

[2] The exact rules and eligibility criteria for the H2 PTC were still being developed at the time this Addendum was written.

materials; applies to all projects placed in service or sold in 2023 or later; creates new credits for standalone storage, small modular nuclear reactors, and other technologies; allows for PTCs for renewables to be stacked with storage and fuels production; and provides higher credits for CCS including a new credit for DAC. In addition, the IRA establishes prevailing wage and qualified apprentice requirements for project developers to access the highest value tax credits. E3 assumes that projects will have access to the full credit amounts, with the underlying assumption that the prevailing wage and apprenticeship requirements are satisfied. In addition, the IRA tax credits will phase out the later of 2032 or when the US electric sector achieves 75% GHG emissions reduction relative to 2022 levels.[3] E3 assumes that the electric sector emissions target will be met by 2045, after which the IRA tax credits step down over a three-year period.

Figure 7: Tax Credit Schedules Pre- and Post-IRA Assuming Prevailing Wage and Apprenticeship Requirements are Met



3 Results

3.1 The IRA Will Reduce GHG Emissions in Maryland

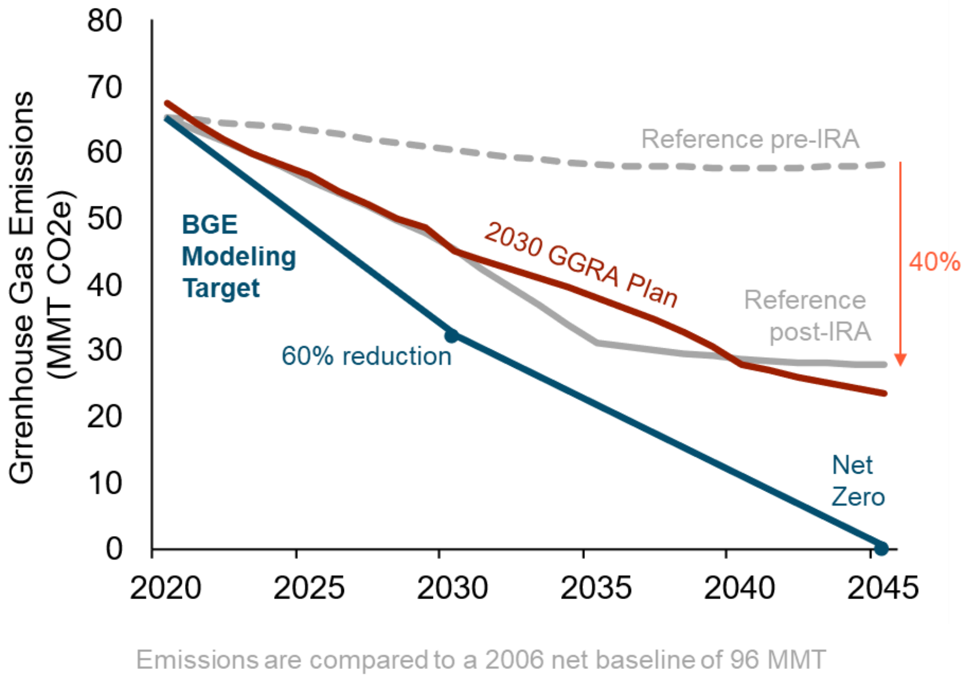
The IRA will support the state of Maryland and BGE in accelerating progress towards decarbonization goals primarily through: 1) by accelerating transportation electrification and 2) by reducing emissions in the electric sector inside the state of Maryland and in the broader PJM market. In the electric sector,

[3] https://www.energy.gov/sites/default/files/2022-10/IRA-Energy-Summary_web.pdf.

expansions of the ITC and PTC will spur development of renewable energy generation and supporting energy storage projects. In the transportation sector, tax credits will accelerate the market for passenger electric vehicles.

Applying these incentives and modeling how they will affect adoption of decarbonization measures shows that the IRA is likely to put the state on a trajectory towards a 40% reduction in 2045 emissions under a business-as-usual scenario.

Figure 8: Maryland State Emissions Trajectories



While the IRA makes significant progress in support of Maryland's decarbonization goals, there is still a gap between the post-IRA Reference scenario emissions and the emissions targets set under SB0528. To meet these targets and achieve 60% emissions reduction, relative to 2006, by 2030 and net zero emissions by 2045, additional support is needed. This support would cover building decarbonization, freight vehicle decarbonization, clean electric generation resources, and industrial sector decarbonization.

3.2 The IRA Supports Electric Sector Decarbonization and Could Spur Deployment of Technologies that Reduce the Challenge of Serving a Winter Peaking PJM System

E3's 2022 Report leveraged existing modeling[4] of the PJM system to capture the cost of decarbonizing Maryland and regional electric generation. In order to capture the impact of the IRA for this updated

[4] See, E3 Report: Least-Cost Carbon Reduction Policies in PJM States - EPSA

analysis, E3 conducted new electric sector modeling using E3's least-cost capacity expansion model, RESOLVE. RESOLVE is an optimization model that ingests the load outputs from our PATHWAYS model and identifies a portfolio of generation resources that meet reliability, clean energy and climate goals.

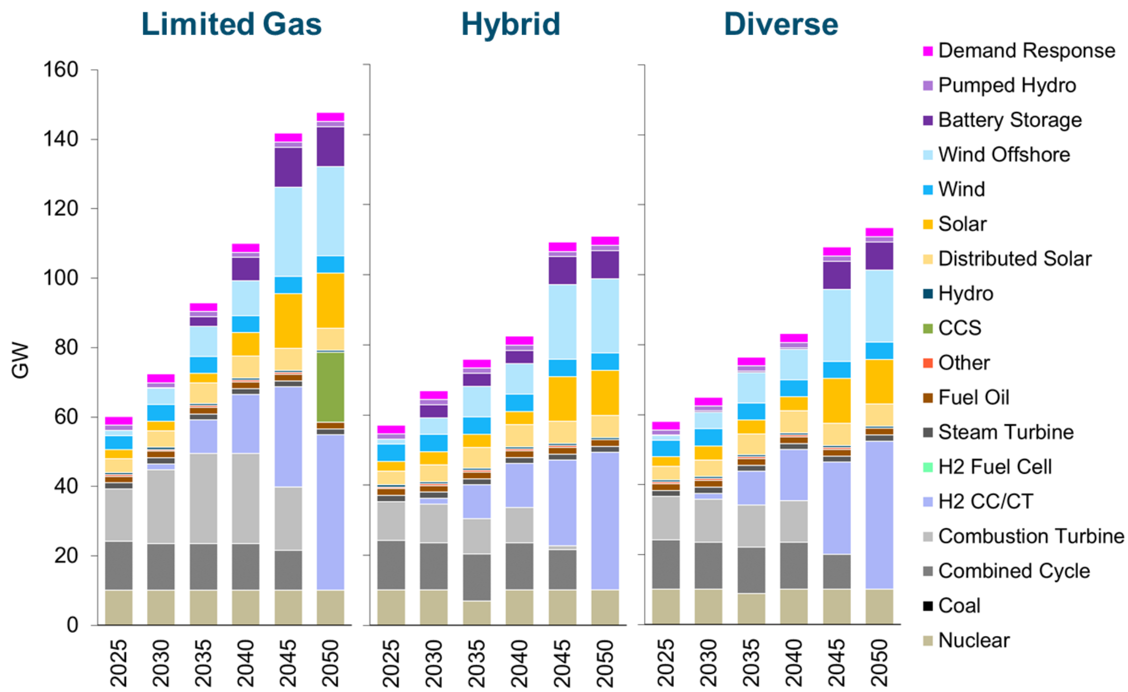
For this analysis, the entirety of PJM was modeled as three regions: West, Central, and East (i.e., EMAAC, including BGE). For the Reference scenarios, the Western and Central regions assumed the business-as-usual trajectories, plus any active policies (e.g. IRA or Clean Energy and Jobs Act in Illinois). For the decarbonization scenarios, generation in all PJM regions is assumed to achieve 100% GHG emissions reductions by 2050.

Demand assumptions vary according to the respective scenarios. The Western region was aligned with the Moderate Electrification case from recent E3 work in Illinois and the Central region was generally aligned with the assumptions for the Diverse scenario from the BGE study. The East region was modeled with scenario-specific loads that are consistent with the Limited Gas, Hybrid and Diverse scenarios from our previous BGE report. This approach was designed to capture the cost of decarbonization across PJM, while at the same time isolating the impacts of the three alternative scenarios within the region of PJM that BGE is primarily served by. A more detailed comparison of assumptions for each region can be found in Appendix 1.

In this updated analysis, E3 identified a higher need for clean firm generation capacity to reliably meet winter peak demand relative to our previous work. E3's 2020 PJM study reflected a summer-peaking system where resources like solar and storage can meet a share of peak demands. In the summer, those demands are driven by late afternoon and early evening cooling loads. In contrast, this updated modeling captures situations where peak demands occur in winter mornings and evenings, as well as periods of sustained low wind- and solar output. As a result, renewables and storage resources provide less capacity value in this updated modeling. All else equal, this modeling refinement increases electric sector costs relative to the pre-IRA scenarios. However, this cost increase is offset by IRA incentives that subsidize renewables, storage, CCS, and H2.

Winter peaks are driven by electric heating demand from buildings and this impact is most pronounced in the Limited Gas scenario. Scenarios that take an integrated approach and utilize gas back-up for heating (e.g. the Hybrid and Diverse scenarios) have lower peak demands and therefore require smaller electric grid builds. In effect, these scenarios leverage the existing firm capacity of BGE and neighboring utilities' gas distribution systems in lieu of building grid-scale firm capacity.

Figure 9: East/EMAAC Portfolio Builds by Scenario



Installed capacity is at least double (Diverse & Hybrid), and up to 2.5x (Limited Gas) that of the Reference case (post-IRA). On a resource-by-resource basis:

- Nuclear is relicensed in all cases, including Reference;
- Natural gas combustion turbines (CTs) and combined cycle (CC) units are kept online until clean firm capacity is needed to fulfill GHG reduction goals;
- Hydrogen is selected as a firm, GHG-free resource starting in the early 2030s, when the cost of H2 production is at its lowest due to the H2 PTC, and is further used to meet the 100% GHG reduction goal by 2050;
- Most available onshore wind is built by 2030 in every scenario; offshore wind is the largest source of renewable generation towards mid-century;
- Solar and battery storage are built in all scenarios, however those these resources have diminishing reliability value as the system peak shifts towards winter;
- In the Limited Gas scenario, natural gas with CCS is built in 2050 to meet the higher peak load in that case.

E3 notes that while these resources were optimized based on the best available information today, the costs of many technologies are uncertain over the study period. Despite that uncertainty, findings emphasize the need for clean firm capacity in the future and that the need for clean firm capacity is highest in scenarios that more fully electrify heating. Whether that firm capacity will be best served via hydrogen, CCS, nuclear, long-duration storage (not modeled), or other resources remains to be seen.

3.3 BGE Electric Rate Impacts from IRA are Similar to Pre-IRA Work

E3's electric rate projections are built in part on our modeling of generation capacity and grid expansion throughout the wider PJM system. In our previous analysis for BGE, E3 leveraged existing PJM-wide cases developed in 2020 for the Electric Power Supply Association (EPSA) and post-processed impacts for BGE based on its changing loads. For this update, E3 modeled all of PJM in futures consistent with economy-wide decarbonization.

While the IRA reduces the cost to customers of any given electric resource, several modeling refinements put upward pressure on total electric sector costs. Modeling updates and their rate impacts include:

- Higher natural gas prices[5] offset savings from IRA subsidies in the ***near-to-mid term***.
- Higher loads across PJM, which lead to more costly tranches of zero-GHG generation (e.g. more off-shore wind) in the ***mid-to-long-term***
- PJM shifts to winter peaking in all scenarios, which reduces the effective load carrying capability (ELCC)[6] of renewables and storage, leading to larger firm capacity builds in the ***mid-to-long-term***
- Impacts on distribution costs are unchanged, because the IRA does not provide incentives for distribution infrastructure.

With those factors considered, E3's analysis suggests that net-zero scenarios will put upward pressure on BGE's electric rates relative to business-as-usual. Those impacts are driven by a combination of higher electric supply costs and increased peak demand for BGE's transmission and distribution systems. Rate impacts are lower for the Hybrid and Diverse scenarios because, in those cases, changes in electric peak demand are lower.

3.4 Gas Rates are Incrementally Lower Relative to Pre-IRA Work

The IRA produces modest downward pressure on gas supply costs in the Hybrid and Diverse scenarios due to the hydrogen PTC. However, most usage of those fuels in the scenarios occurs after the tax credit expires, so cost impacts are small. Those impacts are largest in the Diverse scenario, which relies on hydrogen and synthetic natural gas the most. The IRA does not impact gas delivery rates, which are the largest source of gas rate escalation in all scenarios. Reducing those costs would require the development of targeted electrification or other gas system decommissioning initiatives. The methane fee also has small impacts on the cost of natural gas.

3.5 Overall Customer Affordability is Improved

With the impacts of the IRA, monthly customer energy costs are reduced for all customer types. The IRA put modest downward pressure on gas rates, and therefore gas bills, due to the H2 PTC reducing

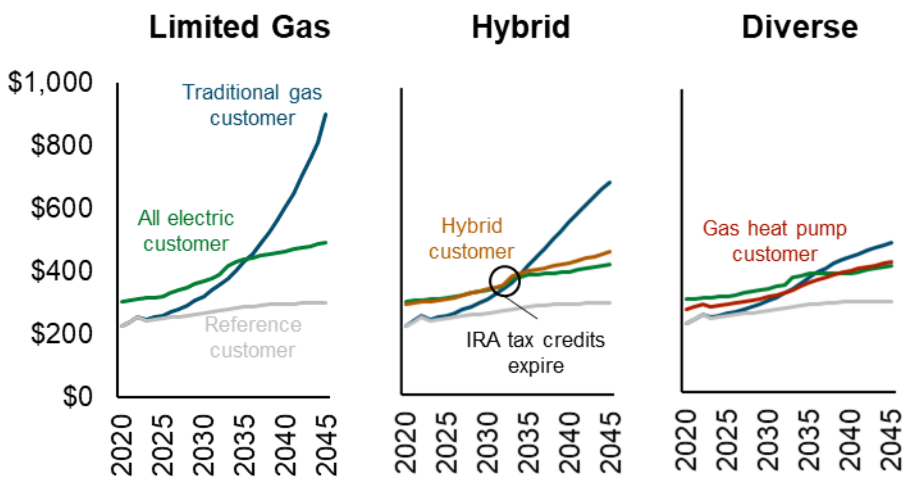
[5] Representative of updated PJM forecasts and inclusive of IRA methane fee impacts

[6] Given the first study found that electrification pushed the system from a summer to a winter peaking system, updates were made to the reliability accounting to better reflect the impacts of this change

commodity costs for hydrogen and SNG. The residential IRA tax credits reduce the upfront costs of electrification when the credits are applied to air-source heat pumps, other home electric appliances, and electric vehicles. Residential tax credits are also available for building shell insulation and weatherization, increasing energy efficiency and reducing energy bills. The IRA tax credits are assumed to expire in 2032, causing an increased in levelized monthly energy costs after this year.

Residential energy costs are also lower with the IRA than they were in E3's 2022 Report due to improvements in how air conditioning loads were modeled. Even so, customers transitioning away from gas appliances still experience higher costs in the near-term and become cheaper than the gas alternative post-2035.

Figure 10: Monthly Energy Bills and Levelized Equipment Costs of a Representative BGE Customer

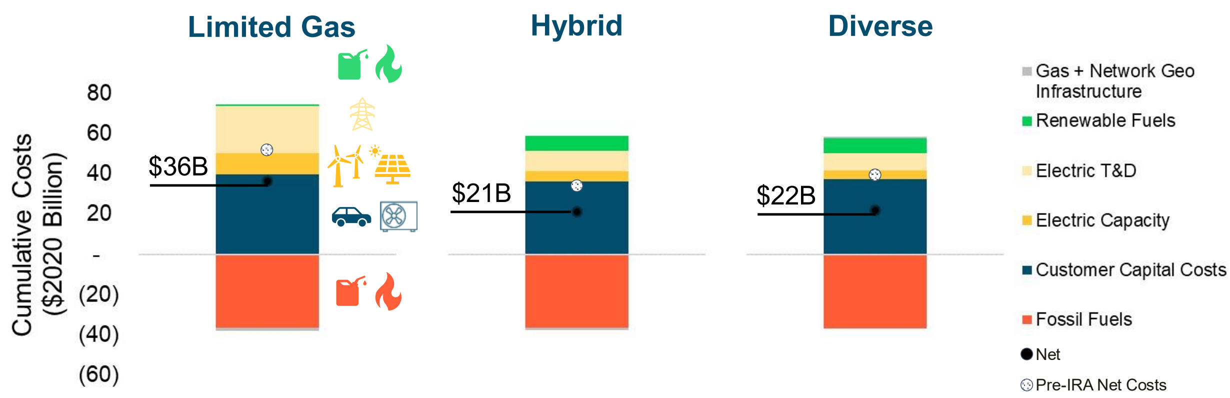


[11]

3.6 Incremental Costs to BGE's Customers and the State of Maryland are Reduced

IRA incentives spur electric sector decarbonization and passenger vehicle electrification under business-as-usual. As a result, the incremental costs of achieving net-zero are lower for BGE's customers than they would be without the IRA incentives. In addition, the incremental costs of achieving net-zero in each scenario are reduced because Federal taxpayers are paying for a larger share of decarbonization measures under the IRA.

Figure 12: Cumulative Incremental Total Energy System Costs by Scenario (2020 – 2045)



Note that customer capital costs, represented in dark blue, do not include IRA impacts in this chart given the complicated eligibility for those tax credits. However, those impacts are incorporated in Figure 10. To put these costs into context, Maryland's gross state product (GSP) in 2020 was $411 billion. Cumulative incremental energy system costs from 2020-2045 are $20-35 billion, which is less than 0.3% of cumulative GSP over the same period. Cumulative avoided emissions 2020-2045 are 483-492 MMT CO2e. Applying the existing EPA mid value for social cost of CO2, the approximate avoided emissions benefits are approximately $27 billion over the study period[7]. Under a recently proposed update to the social cost of carbon, those savings would rise to $68 billion[8]. Additionally, air quality benefits from these scenarios were not factored into the total costs and E3 expects that doing so would lead to every scenario providing a net benefit to Maryland.

4 Key Takeaways

The IRA reduces the total incremental costs of achieving net-zero in BGE's service territory across all the scenarios considered in this analysis. However, in comparing the scenarios to one another, the main points and results from the E3 2022 report still hold. Those points include:

- **There are multiple viable paths to decarbonization**, but any future that meets net zero will require significant transformations and investments across the economy and a role for electrification in buildings and transportation. The IRA provides critically needed support for transportation and building electrification and clean electricity generation that reduces the emissions gap to net-zero.

[7] 3% discount rate average case from The Social Cost of Carbon | Climate Change | US EPA

[8] 2% discount rate case from Supplementary Material for the Regulatory Impact Analysis for the Supplemental Proposed Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review": EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

- **Pathways that rely on an integrated energy system carry a lower overall cost and level of challenge relative that rely more exclusively on electrification or renewable gases.** While the inclusion of IRA incentives has decreased the cumulative incremental total energy system costs of each pathway, the Hybrid scenario and Diverse scenarios are still lower cost.

- **Consumers are central to the transformations required to achieve net-zero** and achieving scale will require developing solutions that are affordable and work for customers. Incentives provided by the IRA will increase the baseline level of electrification in the reference scenario, particularly within the transportation sector. However, all mitigation scenarios require higher levels of electrification, so meeting a net zero target will require further investment and greater incentives.

- **Regulatory and policy support will be necessary to both manage the challenges associated with decarbonization and capture new opportunities.** Although the IRA will provide support and incentives on a federal level, additional regulatory and policy support will be needed. This could include, but is not limited to, enabling BGE and its customers to support the state's decarbonization ambitions to manage the cost impacts of implementing decarbonization, supporting customer adoption of electrification technologies, and implementing non-pipe alternatives projects.

- **BGE has a critical role in enabling decarbonization in Maryland.** BGE is Maryland's largest utility, and could facilitate the scaling of decarbonization technologies including, but are not limited to, strategic electrification, networked geothermal, and green hydrogen production and delivery. Regardless of scenario, BGE's infrastructure will deliver most of the energy utilized in its service territory, so the company's role in building and maintaining safe, reliable and affordable energy delivery systems will continue to be critically important to achieving Maryland's climate goals.

5 Appendix 1: PJM Modeling Assumptions

A.1. RESOLVE Modeling Assumptions

The RESOLVE model inputs used in this study are derived from a similar model developed for the *Illinois Decarbonization Study*[9] and the *Least-Cost Carbon Reduction Policies in PJM* study[10] performed by E3. Key inputs and assumptions, especially ones that reflect updated data sources are summarized in this section. Additional description of the inputs and assumptions can be found in the prior mentioned studies.

5.1.1 System Topology

RESOLVE models the PJM system as a whole and uses a zonal transmission topology to simulate power flows among the three zones represented in the model, i.e., Eastern Mid-Atlantic Area Council (EMAAC), Central (regional transmission organization, or RTO), and ComEd. While zones may vary each year as system conditions change, these still capture the core regions with common dynamics in PJM. No external zones were modeled in RESOLVE[11], meaning PJM is unable to import or export to the MISO, the New York Independent System Operator (NYISO), or the Tennessee Valley Authority (TVA). Model zones align with the capacity auction zones of ComEd (Chicago: ComEd in Northeastern Illinois), EMAAC (East: Load serving entities (LSEs) in the regions of New Jersey, Delaware, Southeast Pennsylvania, and Eastern Maryland), and RTO (Central: Remaining LSEs in central PJM).

High-level transmission constraints in the PJM grid are also presented in the model. The zonal import and export capabilities are taken as 5,781 MW for transfers between ComEd and RTO, and 14,322 MW for transfers between EMAAC and RTO. These values are based on the Capacity Emergency Transfer Limits

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[9] "Illinois Decarbonization Study: Climate and Equitable Jobs Act and Net Zero by 2050." December 2022. https://www.ethree.com/wp-content/uploads/2022/12/E3-Commonwealth-Edison-Decarbonization-Strategy-Report.-December-2022-1.pdf

[10] "Least-Cost Carbon Reduction Policies in PJM." October 2020. https://www.ethree.com/wp-content/uploads/2020/10/E3-Least_Cost_Carbon_Reduction_Policies_in_PJM-1.pdf.

[11] One representation of external resources was modeled via the 2 GW SOO Green Transmission line

(CETLs) in the PJM 2023/2024 Base Residual Auction. Figure 13 shows the existing topology of PJM system modeled in RESOLVE.

Figure 13: PJM Transmission Topology Modeled in RESOLVE

In addition to the existing transmission capacity, the model includes approximately 2,000 MW of new SOO Green transmission from the Midcontinent Independent System Operator (MISO), scheduled to be added in 2027 and connected to PJM system through ComEd.

5.1.2 Demand Forecasts

Annual energy demands by region are calculated from E3's PATHWAYS model. Annual system peaks are calculated from annual energy (from PATHWAYS, analysis year from 2020 to 2050) and load profiles (from RESHAPE, 40 historical weather-year data). For each analysis year, the median ("1-in-2") coincident peak out of the 40 historical weather years is chosen as the system peak. Load assumptions vary by scenario and region and are described in **Error! Reference source not found.**.

Table 1: Constant Scenario Assumptions for the West and Central Regions of PJM. Assumptions Vary by Scenario for the East/EMAAC Region to Evaluate Scenario Differences for BGE.

Sector	West/ComEd (Moderate Electrification)	Central (Diverse)	East/EMAAC		
			Limited Gas	Hybrid	Diverse
Buildings	100% sales of heat pumps by 2035, majority with gas backup heat	Air and ground source heat pumps - 30% by 2025 and 70% by 2035 Includes a diverse mix of technologies: dual-fuel systems, all-electric with resistance backup, networked geothermal systems, and thermal heat pump systems2 Efficient fossil equipment remainder of sales	Electric heat pumps - 30% by 2025 and 50% by 2035 Efficient fossil equipment remainder of sales	Electric heat pumps - 10% by 2025 and 30% by 2035 Dual fuel heat pumps - 20% by 2025 and 50% by 2035 Efficient fossil equipment remainder of sales	Electric heat pumps - 10% by 2025 and 30% by 2035 (split between ASHP and network geo)2 Dual fuel heat pumps - 5% by 2025 and 15% by 2035 Thermal heat pumps - 1% by 2025 and 25% by 2035 Efficient fossil equipment remainder of sales

Sector	West/ComEd (Moderate Electrification)	Central (Diverse)	East/EMAAC		
			Limited Gas	Hybrid	Diverse
Transportation	LDV - 100% ZEV sales by 2035 MHDV - 100% ZEV sales by 2045 for MHDV (role for HFCV)	LDV - 100% new sales EVs by 2035 MDV - 65% new sales ZEVs by 2030 and 100% by 2045 HDV - 35% new sales of electric/renewable diesel/CNG/hydrogen vehicles by 2030 and 100% by 2045	LDV - 100% new sales EVs by 2035 MDV - 65% new sales ZEVs by 2030 and 100% by 2045. 100% EV and 0% FCEV. HDV - 35% new sales of electric//hydrogen vehicles by 2030 and 100% by 2045. 75% EV, 25% H2 Bioenergy to decarbonize aviation and offroad vehicles H2 refueling	LDV - 100% new sales EVs by 2035 MDV - 65% new sales ZEVs by 2030 and 100% by 2045. 90% EV and 10% FCEV HDV - 35% new sales of electric/renewable diesel/CNG/hydrogen vehicles by 2030 and 100% by 2045. 25% EV, 50% H2, 25% other Bioenergy to decarbonize aviation, offroad vehicles, and HDVs H2 refueling CNG fleets	LDV - 100% new sales EVs by 2035 MDV - 65% new sales ZEVs by 2030 and 100% by 2045. 90% EV and 10% FCEV HDV - 35% new sales of electric/renewable diesel/CNG/hydrogen vehicles by 2030 and 100% by 2045. 25% EV, 50% H2, 25% other Bioenergy to decarbonize aviation, offroad vehicles, and HDVs H2 refueling CNG fleets

Sector	West/ComEd (Moderate Electrification)	Central (Diverse)	East/EMAAC		
			Limited Gas	Hybrid	Diverse
Industry	~10% of natural gas use converted to electricity by 2050, remaining ~90% converted to H2 combustion CCS implemented for coal use in certain industries Phase down in refining activity associated with IL demand	Moderate (~40%) electrification of "high potential" industrial end uses by 2045 Dedicated hydrogen clusters developed for applicable industrial processes by 2045 Alternative fuels used to decarbonize hard-to-electrify industrial end uses Some fuel switching to natural gas from other fuels for hard-to-electrify industrial end uses	High (~80%) electrification of high potential industrial end uses by 2045 Alternative fuels used to decarbonize remaining hard-to-electrify industrial end uses Aggressive energy efficiency pursued	Moderate (~40%) electrification of "high potential" industrial end uses by 2045 Dedicated hydrogen clusters developed for a portion of applicable industrial processes by 2045 Alternative fuels used to decarbonize hard-to-electrify industrial end uses Aggressive energy efficiency pursued Dedicated hydrogen clusters	Moderate (~40%) electrification of "high potential" industrial end uses by 2045 Dedicated hydrogen clusters developed for applicable industrial processes by 2045 Alternative fuels used to decarbonize hard-to-electrify industrial end uses Some fuel switching to natural gas from other fuels for hard-to-electrify industrial end uses Aggressive energy efficiency pursued Dedicated hydrogen clusters Fuel switching

Sector	West/ComEd (Moderate Electrification)	Central (Diverse)	East/EMAAC		
			Limited Gas	Hybrid	Diverse
Electricity	100% GHG Emissions Reduction by 2050				

Figure 14: Annual Energy Demand Modeled in RESOLVE

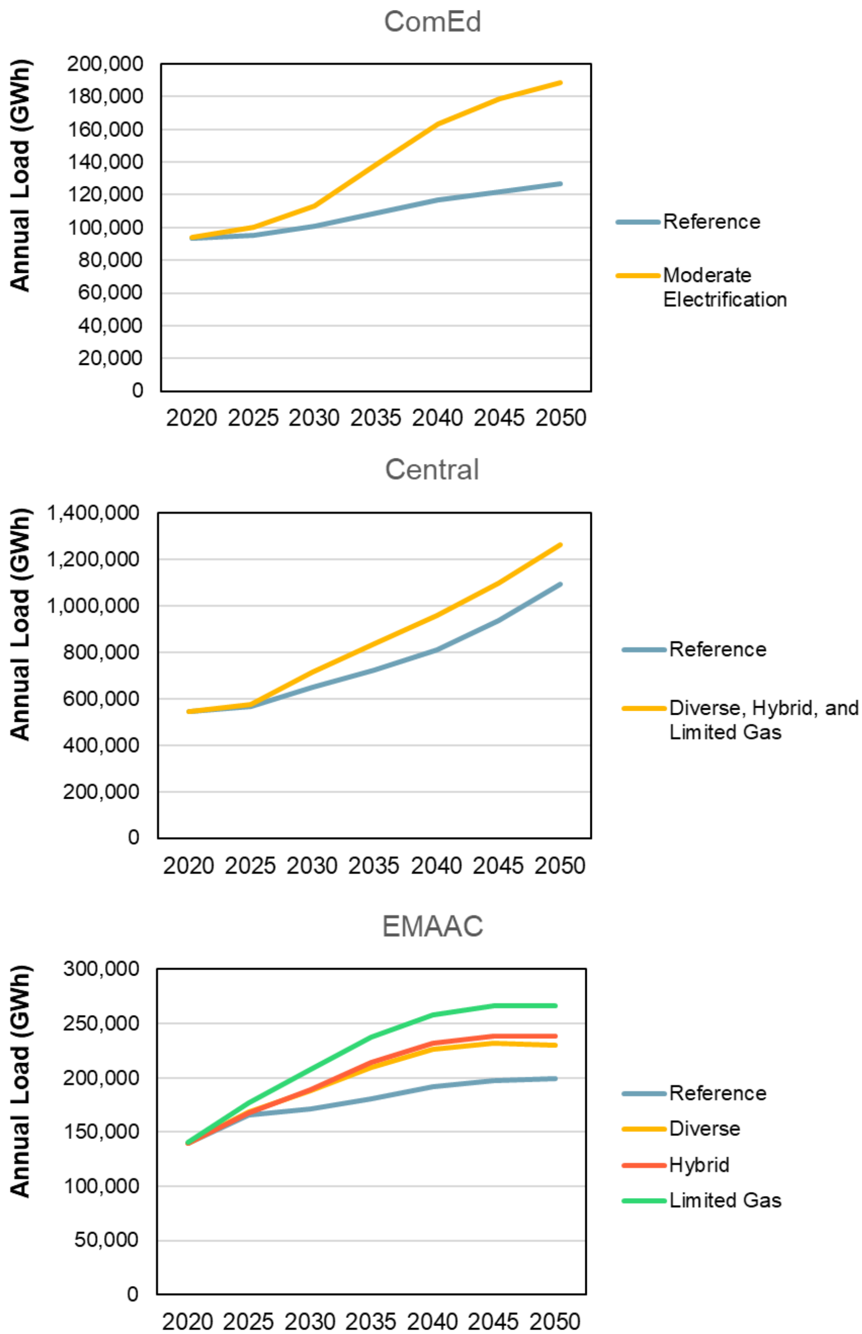

Figure 15: Annual Peak Load Modeled in RESOLVE