# ANNUAL DECARBONIZATION PERSPECTIVE

## CARBON-NEUTRAL PATHWAYS FOR THE UNITED STATES

## 2024

## ABOUT THIS REPORT

This report explores options for long-term deep decarbonization pathways for the United States. It is the third in a series of annual updates that aim to move pathways analysis beyond isolated proofs-of-concept toward becoming a practical implementation tool for addressing next-stage challenges in energy and climate change mitigation.

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EVOLVED ENERGY RESEARCH

## ABOUT EVOLVED ENERGY RESEARCH

Evolved Energy Research (EER) is a research and consulting firm focused on questions posed by transformation of the energy economy. Its consulting work and insight, supported by sophisticated technical analyses of energy systems, is designed to support strategic decision-making for policymakers, stakeholders, utilities, investors, and technology companies.

We are pleased to present the third Annual Decarbonization Perspective (ADP), a comprehensive analysis of America's pathways to net zero. Authored by our partners, Evolved Energy Research, the ADP stands out in its scope and detail, offering the only US-wide decarbonization study produced on an annual basis that is exhaustive and granular enough across regions, technologies, and time to address the complexities of the energy transition.

At Breakthrough Energy, we are proud to support this essential study, which delivers up-to-date, transparent data to advance clean energy policies, guide resource planning and investments, and accelerate technology commercialization. The ADP has become a vital resource for utilities, government agencies, investors, and nonprofits working to implement the clean energy transition, democratizing access to high-quality research.

This year, in line with Breakthrough Energy's commitment to developing and scaling next-generation clean energy technologies, the ADP explored promising innovative solutions like geologic hydrogen, next-generation geothermal, and low-carbon cement and examined how emerging solutions can meet the surging electricity demand driven by data centers and the artificial intelligence revolution. The study also provides an updated view of its six core pathways for the US to reach net zero by mid-century, incorporating the latest data on technology costs and resource availability. As novel technologies mature, new solutions emerge, and market dynamics evolve, up-to-date analysis is crucial to guide policy and investment.

The results underscore the critical need for collaboration between policymakers and industry leaders to drive innovation and deploy clean energy at scale. Continued government support for research, development, and market adoption is crucial to driving down the costs of clean technologies needed to make the economy work for the climate.

With the insights provided by the ADP we can direct our efforts toward the most impactful solutions, accelerating the development of essential technologies and driving the transformational change needed to build a prosperous, clean energy future.

David Paolella
Manager, U.S. Policy and Advocacy
**Breakthrough Energy**

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| | |
|---|---|
| **AEO** | Annual Energy Outlook |
| **ADP** | Annual Decarbonization Perspective |
| **ATB** | Annual Technology Baseline |
| **BECCS** | Bioenergy with carbon capture and storage |
| **CCS** | Carbon capture and storage |
| **CCUS** | Carbon capture, utilization, and storage |
| **$CO_2$** | Carbon dioxide |
| **$CO_2e$** | Carbon dioxide equivalent |
| **COBRA** | Co-Benefits Risk Assessment |
| **DAC** | Direct air capture |
| **DDPP** | Deep Decarbonization Pathways Project |
| **DOE** | Department of Energy |
| **EER** | Evolved Energy Research |
| **EIA** | Energy Information |
| **EJ** | Exajoule |
| **EV** | Electric vehicle |
| **FAME** | Fatty acid methyl ester |
| **GDP** | Gross domestic product |
| **GHG** | Greenhouse gas |
| **Gt** | Gigatonne |
| **GW** | Gigawatt |
| **H2** | Hydrogen |
| **HEFA** | Hydroprocessed esters and fatty acids |
| **HTGR** | High-temperature gas reactor |
| **HVAC** | Heating, ventilation, and cooling |
| **IRA** | Inflation Reduction Act |
| **ISO** | Independent system operator |
| **kWh** | Kilowatt-hour |
| **LCOE** | Levelized cost of energy |
| **MHa** | Million hectares |
| **MJ** | Megajoule |
| **Mt** | Megatonne |
| **MW** | Megawatt |
| **NEMS** | National Energy Modeling System |
| **NERC** | North American Electric Reliability Council |
| **NOx** | Nitrogen oxides |
| **NPV** | Net present value |
| **NREL** | National Renewable Energy Laboratory |
| **OSW** | Offshore wind |
| **$PM_{2.5}$** | Particulate matter with diameter less than 2.5 microns |
| **PV** | Photovoltaic |
| **R&D** | Research and development |
| **ReEDS** | Regional Energy Deployment System |
| **RIO** | Regional Investment and Operations |
| **RTO** | Regional transmission operator |
| **SMR** | Small modular reactor |
| **SOx** | Sulfur oxides |
| **TES** | Thermal energy storage |
| **TWh** | Terawatt-hour |

ES

# EXECUTIVE SUMMARY

## What is the Annual Decarbonization Perspective?

The 2024 Annual Decarbonization Perspective (ADP 2024) from Evolved Energy Research describes technical strategies for the United States to achieve net-zero greenhouse gas emissions economy-wide by 2050. It was produced using state-of-the-art modeling tools to evaluate the infrastructure, technology, land use, and cost requirements of different net zero pathways, creating scenarios that highlight key decision points, tradeoffs, and opportunities on the road ahead. *ADP 2024* is the third in a series that refines and updates its projections and recommendations annually, responding to the latest changes in technology and policy. The goal of the *ADP* series is to provide policymakers, investors, researchers, and stakeholders across all sectors a rigorous foundation on which to plan and implement a transition to net-zero consistent with maintaining the economic productivity and energy security of the U.S.

## Technology Breakthroughs and Net Zero

A global transition to low-carbon energy requires affordable and scalable technologies to protect the climate while improving economic opportunities, standards of living, access to healthcare, and other essentials of modern life. Technology cost breakthroughs in the U.S. reduce the burden on policy alone to drive this transition, reducing the overall cost of decarbonization, and also making the transition more affordable globally, accelerating progress toward net-zero. The more options exist, the more resilient decarbonization pathways become; a diverse set of technology solutions can better adapt to regional differences, societal preferences, and policy environments.

This year, *ADP 2024* features an in-depth focus on three specific aspects of the emerging technology landscape:

- The explosive growth of electricity demand from data centers, driven by the revolution in artificial intelligence
- The unexpected emergence of several promising new technologies — geologic hydrogen, next-generation geothermal, and LC3 cement — that make difficult decarbonization problems more solvable
- The cost breakthroughs that key carbon-free technologies and fuels must achieve to be competitive without policy interventions such as tariffs and mandates

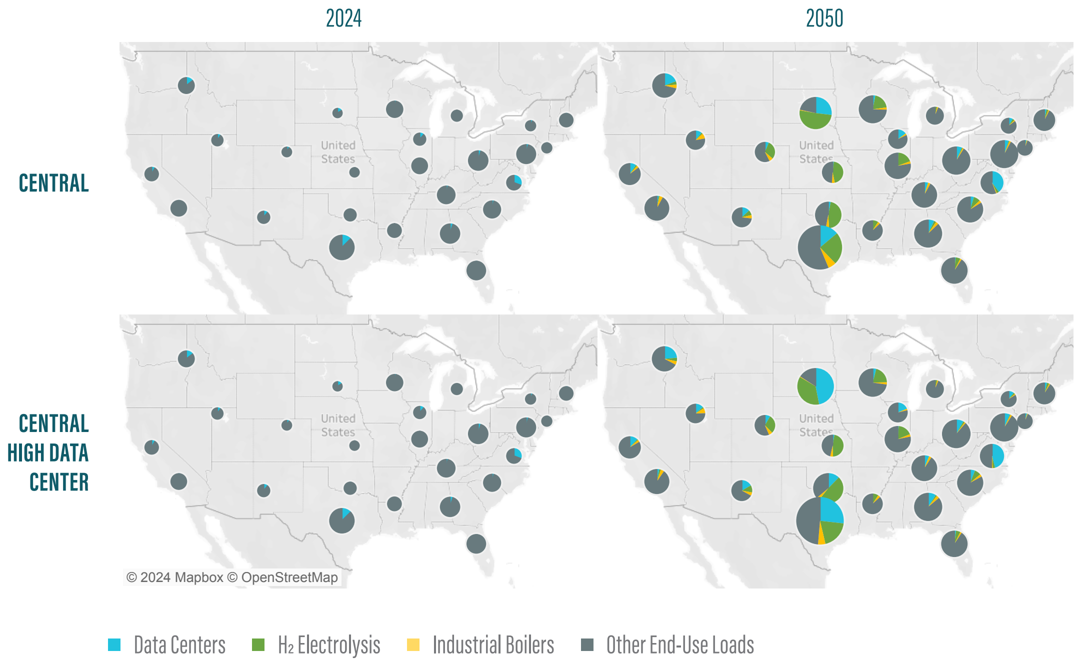
## Data Center Electricity Demand and the Energy Transition

The rapid expansion of data centers, driven by advances in artificial intelligence (AI) and the computational requirements of large language models, is creating a major new source of electricity demand in the United States. *ADP 2024* models data center demand under baseline and high-growth scenarios that range between 975 TWh and 1,680 TWh in 2050, up from 279 TWh today. Even given the rapid electricity demand growth expected from the electrification of transportation and other sectors in a net zero transition, data centers would outpace that growth to consume a share of between 9.3% and 14.9% of total U.S. electricity by 2050.

Given these projections, ensuring that this energy is carbon-free is crucial to reaching net-zero. Data centers differ from many major energy consumers because they require both extremely high reliability and very high utilization of their equipment to justify high capital investments. *ADP 2024* analyzes different system solutions to this problem, with the result being a need to substantially increase the buildout of new renewables, and also of backup capacity from natural gas and electricity storage.

Given that in the lifecycle of an AI model, training often requires far more computation than when customers use the model, and that this training can happen anywhere in the country with no particular latency (time lag from customer query to results) requirements, *ADP 2024* finds there is a potential to economically locate future data centers strategically in regions with low-cost renewable energy, especially in areas within the Midwestern “wind belt.”

**FIGURE ES-1.** Electricity consumption by region and type of demand in 2024 and 2050 for Central and Central High Data Center scenarios. (Data center consumption is in blue).




## Promising Technologies from Unexpected Sources

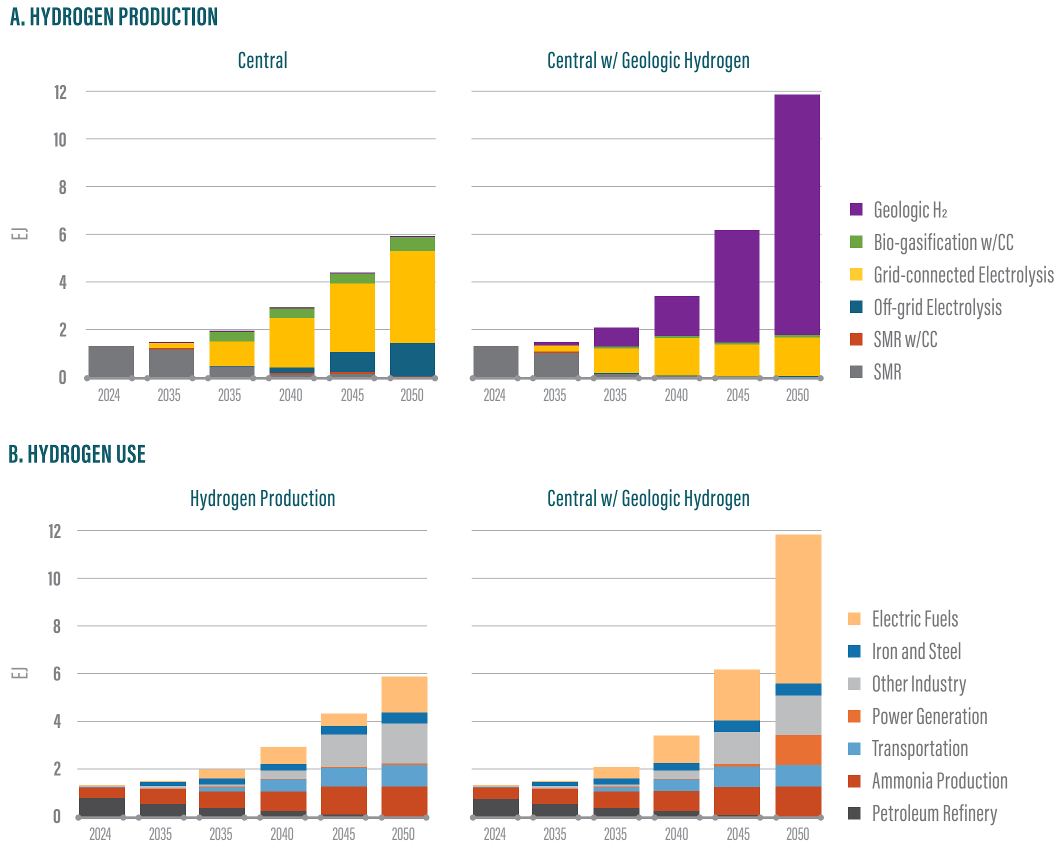
Recent advances in oil and gas technology—specifically horizontal drilling, hydraulic fracturing, and high-pressure fluid pumping—are unexpectedly unlocking new potential in clean energy. For geothermal energy, these methods reduce the cost of drilling wells and producing high-temperature steam, making geothermal energy economically viable beyond a few locations in the western U.S. Next-generation geothermal technology has transformed geothermal from a geographically limited resource to one that can provide economically competitive supplies of thermal energy across much of the U.S.

In addition to the appearance of new geothermal power at significant levels (tens of gigawatts) for the first time, another notable application for geothermal highlighted this year's *ADP* is steam for industry. Unlike electricity generation, which requires higher temperatures, many industrial applications use steam at temperatures of 150° C or below. The new geothermal technology can provide steam at this temperature in many parts of the U.S. *ADP 2024* estimates geothermal's levelized cost of heat (LCOH) for very large steam applications to be around $7/MMBtu by 2035, nearly on par with new natural gas boilers. This positions geothermal as a crucial alternative to fossil fuels for decarbonizing industrial processes. *ADP 2024* also finds that the new geothermal can increase the competitiveness of direct air capture by providing low-cost heat for the recharge of solid sorbents.

Another potentially significant source of clean energy based on oil and gas technology is geologic hydrogen. Geologic hydrogen is generated through natural processes involving water and iron-rich minerals, and may prove to be scalable, widely abundant, and low cost. *ADP 2024* is the first study of economy-wide impacts from a breakthrough in geologic hydrogen on the energy transition. ADP modeling indicates that if geologic hydrogen hits a $1/kg target, $1/kg target, it would result in greater hydrogen use in electric power and industry, and significantly increase synthetic fuel production, reducing the need for geologic carbon sequestration.  In addition, demand for biomass, wind, and solar would decrease in net zero scenarios, saving land.

A third technology that has emerged recently is LC3 (limestone and calcined clay) cement. While alternative cement formulations have been proposed for years, the LC3 formulation developed by researchers in Switzerland, and now being adopted at increasing scale in many developing countries, has the great virtue of using low-cost common minerals to replace a large fraction of the ordinary Portland cement that is the main component of conventional cement, and the source of most of the process emissions. Use of LC3 eliminates a large share of $CO_2$ emissions from cement while reducing the cost of production. *ADP 2024* explores the requirements of a switch to LC3 cement, in combination with LEILAC direct separation CCS technology, to produce net zero cement in the U.S. The results show that while the technology is still nascent, the assumption that cement decarbonization may prove intractable is out of touch with recent technology advances.

**FIGURE ES-2.** (Top) Hydrogen production by type in the Central and Geo H2 scenarios out to 2050 (Bottom) Hydrogen demand by end use in the Central and Geo H2 scenarios out to 2050.

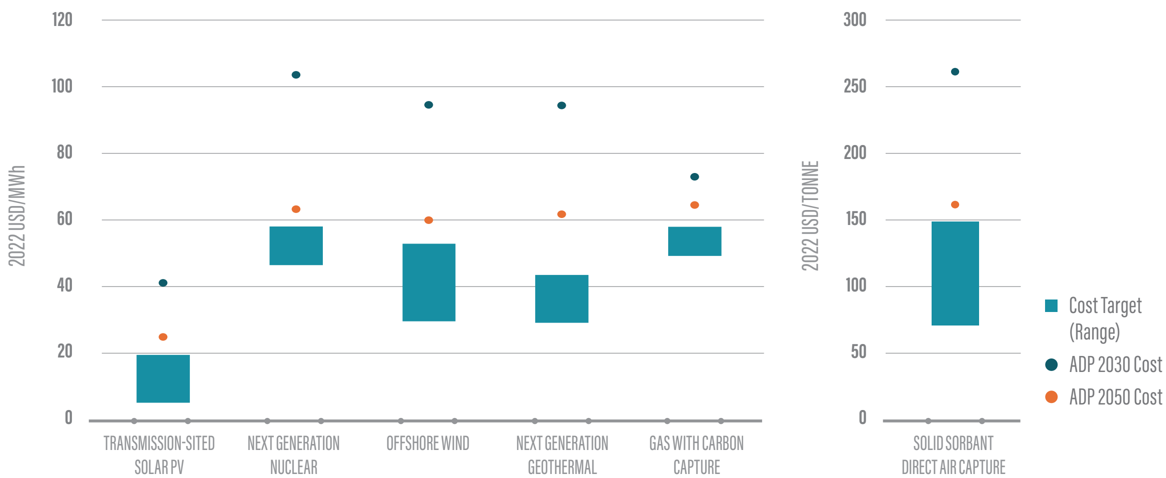



## Cost Targets for Clean Technologies

*ADP 2024* introduces a pioneering approach to setting cost targets for clean technologies such as advanced nuclear and next-generation geothermal, by calculating what each technology would need to cost in order to replace another key clean technology that does not materialize, and to do so at large scale without increasing the overall cost of the energy transition.

Six technologies were analyzed in *ADP 2024* as a proof of concept — nuclear, geothermal, gas with carbon capture, offshore wind, solar, and direct air capture. Any of them could be essential if emerging challenges constrain the buildout of others, for example onshore wind at the scale currently envisioned in net-zero scenarios. Establishing cost benchmarks for these technologies helps stakeholders understand what levels of investment and research are required to make each technology competitive and scalable. *ADP 2024* also calculates the "green premium" for decarbonized fuels relative to conventional fossil fuels in providing steam, hydrogen, and aviation fuel.

**FIGURE ES-3.** Required levelized cost range ($/MWh) for low-carbon technologies for reaching deployment targets in Central and Current Policy scenarios




***Note.*** *The dark blue and orange dots represent the levelized cost assumed in ADP 2024 for 2030 and 2050 respectively. The solid blue bar provides a range of target costs by technology that depend on the level of policy support for net-zero emissions. The top of the bar is the required cost in the Central scenario. The bottom of the bar is the required cost in the Current Policy scenario (which does not have the policies needed to reach net-zero emissions).*

## Other New Analysis in ADP 2024

*ADP 2024* includes new analysis of several other important decarbonization topics. These include energy efficiency upgrades to residential building shells; new insight into on-road transportation electrification, and the requirements of electricity balancing in a high renewables grid. Scenario results are compared with those in previous ADP reports to illuminate the impact of changes in technology forecasts and policies.

To foster a collaborative approach to climate solutions, *ADP 2024*'s extensive database of national and state-level results and input data is made freely available to researchers, policy analysts, and the general public.

# I INTRODUCTION

## Purpose of this Report

This report explores long-term deep decarbonization pathways for the United States, analyzing different technical strategies for achieving net-zero greenhouse gas emissions economy-wide by 2050. It describes plausible transition paths in all key sectors, especially in energy production and use, but also including land-based carbon sinks and non-energy emissions. Using advanced, fine-grained modeling tools — EnergyPATHWAYS and RIO — we analyze the infrastructure shifts, technological innovations, and economic implications involved in reaching net-zero emissions by mid-century. Our focus remains on how to plan and implement a transition consistent with the continued economic productivity and energy security of the U.S.

This is the third edition of our *Annual Decarbonization Perspective* (ADP) series, which aims to transform pathways analysis from a modeling exercise into actionable strategies for confronting the next set of challenges in the energy transition and climate mitigation. Since our inaugural U.S. ADP in 2022, we have added to our analysis portfolio a sister ADP report for Europe, now in its second year, a useful source of comparison for the U.S.

This report does not prescribe policy, but it does highlight what policy outcomes and technological advances are needed to meet climate goals. It informs investment planning for capital intensive businesses, points to critical gaps in R&D, quantifies potential land use and socio-economic transition challenges, spells out the risks of over-reliance on specific technologies, and helps focus the energy policy debate on useful questions.

## Open Data

As with previous editions, this report is accompanied by a publicly accessible database that details both input assumptions and results. For the second consecutive year, we have made much of this data available at the state level, in addition to the national level. This provides a standard public benchmark for technical analysis and policymaking, facilitating year-on-year comparisons. These comparisons illuminate how changes in technology, cost, policies, and global markets impact decarbonization outcomes and highlight areas where additional policies or investments are needed to stay on track toward net-zero. This data is downloadable from the Evolved Energy Research website.

# II ANALYSIS FRAMEWORK

Our analysis addresses the questions "what are the infrastructure, spending, and natural resources requirements for decarbonizing the U.S. economy by mid-century?" and "how do these elements change if factor X is changed?" Factor X represents many variables of potential importance, from rates of consumer adoption to societal restrictions on what technologies or land uses are allowed. These questions are answered through the modeling of scenarios and comparison of the model results.

## Scenarios

*Scenarios* represent different avenues to decarbonization based on societal preferences or policy restrictions regarding what technologies and resources may or may not be used, although different scenarios also share many elements in common. For each scenario, the pathway to net-zero greenhouse gas emissions in 2050 is modeled in every year starting from the present, for all the infrastructure stocks and activities within all the major economic sectors and subsectors, with a temporal granularity of every hour of the year for electricity, and a geographic granularity of 27 separate regions into which the U.S. is divided.

There are eight scenarios, which are briefly described in Table 1 below. These match the scenarios of the same names modeled in *ADP 2023*.

**TABLE 1.** Scenarios in ADP 2024

| Scenario | Description |
|---|---|
| **Baseline** | This reference scenario is based loosely on the DOE's Annual Energy Outlook 2023 and assumes little electrification of demand-technologies and no IRA tax credits for energy supply technologies. |
| **Current Policy** | This reference scenario is based on Princeton's REPEAT mid scenario and incorporates IRA and IIJA. It has the same demand for energy services as the net-zero cases but does not achieve deep decarbonization. It is used as a basis of comparisons for the cost, emissions, infrastructure, land use and other attributes of the net-zero cases. |
| **Central** | This is the least-cost pathway for achieving net-zero greenhouse gas emissions by 2050 in the U.S. It is economy-wide and includes energy and industrial $CO_2$, non-$CO_2$ GHGs, and the land $CO_2$ sink. It is built using a high electrification demand-side case, and on the supply-side has the fewest constraints on technologies and resources available for decarbonization. |
| **Drop-In** | This net-zero scenario is designed to minimize capital, labor, and institutional disruption. It delays the uptake of electrification technologies by twenty years, caps renewable build at historical rates, and disallows new long-distance transmission or pipelines. |
| **Low Demand** | This net-zero scenario reduces the demand for energy services from that used in the other net-zero scenarios. It is designed to explore how high levels of conservation and energy efficiency, achieved through behavior change, planning, policy, and other means, could reduce requirements for low-carbon infrastructure and land. |
| **Low Land** | This net-zero scenario limits the use of new land for bioenergy crops, wind and solar power generating plants, and transmission lines to 180 thousand square kilometers. This is the same constraint used in *ADP 2022* & *2023* reports and is approximately half of the new land-use in the Central scenario. It is designed to explore the effect of societal barriers on the siting of low-carbon energy infrastructure for environmental and other reasons. |
| **Slow Consumer Uptake** | This net-zero scenario delays by twenty years the uptake of fuel-switching technologies including electric vehicles, heat pumps, fuel-cell vehicles, etc. It is designed to explore the effects of slow consumer adoption on energy system decarbonization, including the impacts on electricity and alternative fuel demand. In many cases, for example the adoption of electric vehicles, the uptake of electric technologies is slower than assumed in the Current Policy scenario. |
| **100% Renewables** | This net-zero scenario allows only wind, solar, biomass, and other forms of renewable energy by 2050. It is designed to explore the effects of eliminating fossil fuels and nuclear power altogether on energy infrastructure, electric power, and the production of alternative fuels and feedstocks. |

## Sensitivities

*Sensitivities* are based on the **Central** scenario and are used to determine the effects on the energy system of changing a limited set of key assumptions or technologies. Four sensitivities were modeled this year, described in Table 2 below.

**TABLE 2.** Sensitivities in ADP 2024

| Sensitivity | Description |
|---|---|
| **Central Geo H2 (Geologic Hydrogen)** | This sensitivity is based on the **Central** scenario but includes 10 exajoules of available geologic hydrogen in 2050 at a cost of $1/kg. |
| **Central High Data Center** | This sensitivity is based on the **Central** scenario but increases the growth rate of data center demand. |
| **Central Limited Biomass** | This sensitivity is based on the **Central** scenario but removes all purpose-grown energy crops and uses low availability assumptions for wastes and residues. |
| **Central No IRA** | This sensitivity is based on the **Central** scenario but excludes IRA tax credits for energy supply technologies. Comparisons with this scenario highlight the impacts of IRA on the development of a net-zero energy system. |

## Exploration of Emerging Technologies

*ADP 2024* takes a deep dive into the economic drivers of deployment for six emerging energy technologies that play roles of greater or lesser importance depending on the scenario. For each, deployment is greater in at least one scenario other than the Central case, indicating that it acts as a substitute for another technology that is constrained in that scenario. To investigate what improvements would be needed to maximize the potential of this technology in unconstrained scenarios, a natural follow-on question is thus: “How much would the cost of a technology need to fall in order to provide the option to deploy it (without increasing system cost) at the scale needed to meet decarbonization objectives if other technologies are less available than we expect?” A further question is “What would this technology need to cost to achieve the same higher level of deployment in the Current Policy scenario (i.e., without a net-zero emissions cap)?” The six technologies analyzed in this way are:

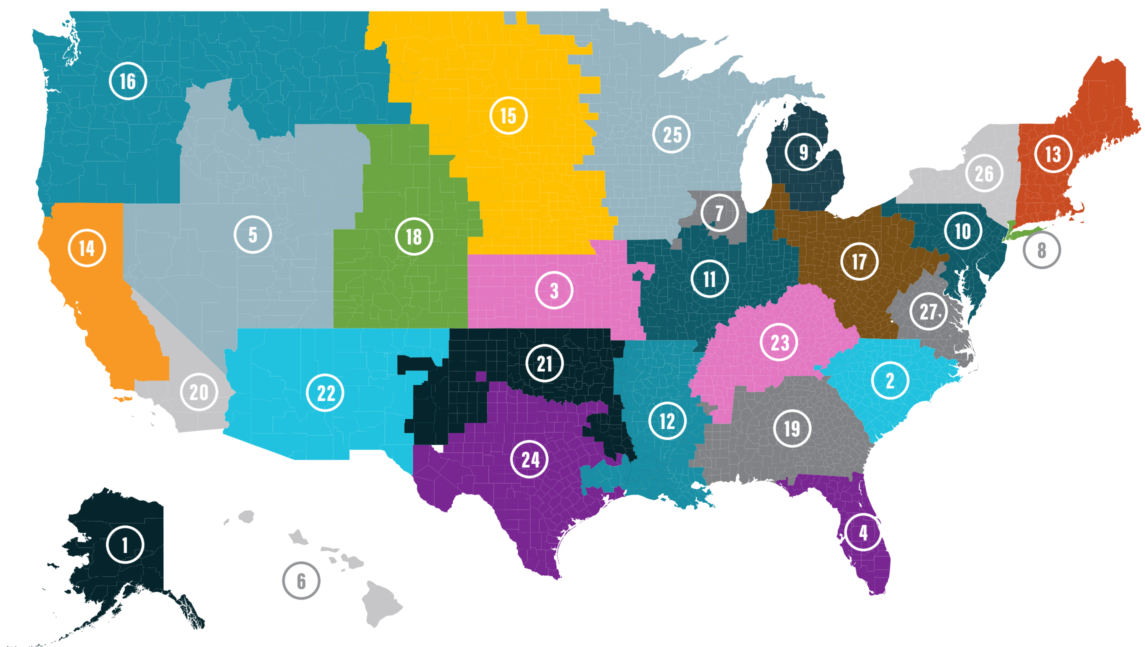
- Direct air capture
- Solar PV
- Offshore wind
- Geothermal
- Gas Power with Carbon Capture
- Advanced Nuclear

## Modeling Dimensions

The EnergyPATHWAYS model operates as a stock accounting tool, calculating both annual and sub-annual energy demand, as well as the costs associated with demand-side equipment, based on user-defined scenarios. The model’s outputs are then integrated into RIO, a linear optimization program that identifies the least-cost pathway for meeting energy demands through 2050 while adhering to constraints such as emissions targets and resource availability. Further details on the modeling methodology can be found in the *ADP Supporting Material*.

The spatial and temporal dimensions in *ADP 2024* are consistent with previous reports. The 27 model zones (Figure 1) follow NERC, ISO, and RTO regional boundaries and use the geographic names from EIA's National Energy Modeling System (NEMS), which are approximations of jurisdictional borders (for example, the "Texas" zone does not fully conform to the borders of that state). Temporally, infrastructure stocks are updated on an annual basis, with hourly resolution across 40 representative sample days per year in electricity system operations including sector coupling with carbon management (CCUS and DAC), fuel production, and other flexible loads (see e.g. Figure 71 to Figure 74).

**FIGURE 1.** Zonal Representation in the Model



| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **1** | Alaska | **8** | Metropolitan New York | **15** | Northern Great Plains | **22** | Southwest |
| **2** | Carolinas | **9** | Michigan | **16** | Northwest | **23** | Tennessee Valley |
| **3** | Central Great Plains | **10** | Mid-Atlantic | **17** | Ohio Valley | **24** | Texas |
| **4** | Florida | **11** | Middle Mississippi Valley | **18** | Rockies | **25** | Upper Mississippi Valley |
| **5** | Great Basin | **12** | Mississippi Delta | **19** | Southeast | **26** | Upstate New York |
| **6** | Hawaii | **13** | New England | **20** | Southern California | **27** | Virginia |
| **7** | Metropolitan Chicago | **14** | Northern California | **21** | Southern Great Plains | | |

# III MODELING UPDATES

## Data Centers

**Improvement:** Artificial Intelligence (AI) has burst onto the national stage since the release of ChatGPT in November 2022. It has also burst onto the energy stage. In combination with cryptocurrency (e.g. bitcoin) mining, AI is triggering an explosion in data center capacity, creating a major new source of electricity demand. The main driver is the computational requirements of the large language models (LLMs) used in AI, roughly an order of magnitude greater per user query than a Google search.[1] As a share of the energy use in AI, training LLMs is especially computationally intensive, requiring approximately five times more computation than the cumulative use of the model after its training.[2] Analysts are divided on exactly how much data center demand will grow in the decades ahead, but agree that the growth will be large, and that the resulting energy demand must be met with carbon-free electricity if the U.S. is to reach net zero by mid-century.[3]

Because of their growing importance, *ADP 2024* is explicitly representing data centers for the first time (to our knowledge, this is also the first time this has been done in a detailed

1 "AI is poised to drive 160% increase in data center power demand," Goldman Sachs, May 14, 2024.

2 Based on internal analysis at Evolved Energy Research with the following assumptions:

- Assume a large language model (LLM) with 400 billion parameters that is trained on 15 trillion tokens (approximate numbers reported for the Llama 3 model from Meta). Each forward pass requires approximately 2 floating point operations (FLOPs) per parameter for a single token, and the backward pass requires 4 FLOPs for a total of 6 FLOPs. This implies training requires 1.5e13 x 4e11 x 6 = 3.6e25 FLOPs for this model.
- Model inference (use) requires only a forward pass, resulting in 2 FLOPs per parameter for one token. If this model is used for one year (before being retrained) and generates 25 billion tokens per day for users, this means its use required 365 x 2.5e10 x 4e11 x 2 = 7.3e24 FLOPs. In this example, training uses 5x the computation that use of the model does over a year. This ratio is sensitive to use assumptions, including how long a LLM gets used before being retrained, but illustrates the basic insight that training requires a relatively large share of total computation.

3 "Climate: The AI Power Grab," *New York Times*, October 22, 2024.

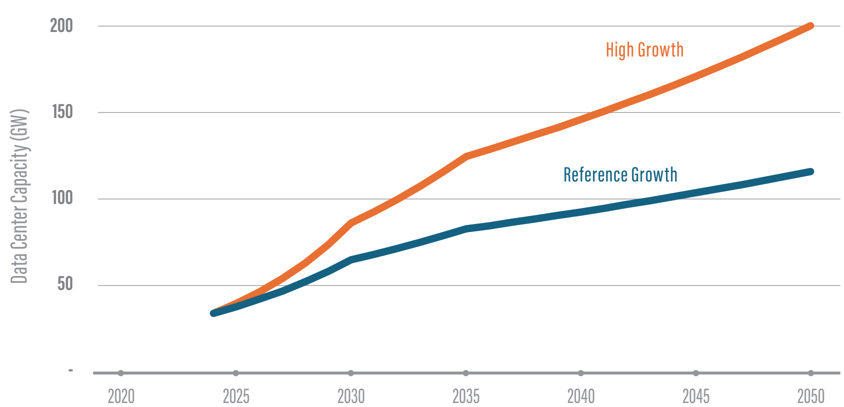
national decarbonization analysis). Accomplishing this required developing our own estimates of future data center demand, since data centers are poorly represented in EIA data, being categorized in the commercial sector under "other" building energy use. DOE did undertake a pilot survey on data centers in the 2018 CBECS (Commercial Building Energy Consumption Survey) but obtained only a 26% response rate, and concluded that producing data center estimates was likely not feasible using current methods.[4] We therefore went through the process of separating data centers from other demand subsectors, using geospatially-explicit data for existing data centers from Baxtel,[5] and conducted a literature review with expert consultation in order to understand possible future growth trajectories.

**TABLE 3.** Compound growth rates for data center demand, reference and high growth scenarios

| Scenario | 2024-2030 | 2030-2035 | 2035-2050 |
|---|---|---|---|
| **Reference** | 14.6% | 6.3% | 2.6% |
| **High Growth** | 17.0% | 7.7% | 3.2% |

The result of this research was two data center demand trajectories with the compound growth rates shown in Table 3. The Reference trajectory was used for all *ADP 2024* scenarios except one — a sensitivity on the Central scenario in which we used the High Growth trajectory. The growth trajectories in both cases reflect the expected explosion of AI in the near term, followed by a moderation of growth as AI use saturates and its efficiency increases. These growth rates result in the data center demand trajectories shown in Figure 2, growing by a factor of three from an anticipated 37 GW in 2025 to more than 115 GW in 2050 in the Reference trajectory, and by a factor of five to over 200 GW in High Growth.

**FIGURE 2.** Data center demand in Reference and High Growth scenarios, 2024 to 2050




4 Energy Information Administration, 2021. 2018 CBECS Data Center Pilot Results. https://www.eia.gov/consumption/commercial/data/2018/pdf/2018_CBECS_Data_Center_Pilot_Results.pdf

5 United States Data Center Market, https://baxtel.com/data-center/united-states

In addition to uncertainty regarding future demand, there is also uncertainty regarding the geographic location of new data center capacity in the future. Currently, data centers are widely distributed across the U.S., driven largely by the need for all markets to have low latency — the lag time between a customer query and a server's response — but there are several "hot spots" with higher-than-average data center concentrations per capita, led by Northern Virginia, Texas, and the Pacific Northwest. In the near term, most indications are that new data centers will be built near where they exist today. In the longer term, however, there is the possibility of siting data centers in locations that are better for reducing energy cost and emissions, especially for capacity used in training, where latency is less of a concern.[6]

In *ADP 2024* we have explored this possibility by allowing half of all data center growth after 2030 to be sited flexibly based on system cost. An important caveat is that this approach only considers the single dimension of energy cost, while many other variables will affect data center siting decisions, including latency, supply chains, work force, and business environment. While not perfect, exploring how energy cost affects siting in net zero scenarios nonetheless provides some interesting insights, as seen in the results below.

**Results:** The contribution of data centers to overall electricity consumption is shown for different scenarios in Figure 3 . The Baseline, Current Policy, and Central scenarios all use the Reference trajectory, which grows to 975 TWh by 2050. For the Central scenario, data centers somewhat outpace the already rapid growth of other loads due to electrification and constitute 9.3% of total consumption by 2050. For the Central High Data Center sensitivity, consumption grows even more rapidly to 1,680 TWh, or 14.9% of total 2050 electricity consumption.

It's noteworthy that the scale and growth rate of data center load resembles that of the electrolysis load for hydrogen production, but these two loads have dramatically different operational characteristics. Data centers require very high reliability, and they must run at very high utilization levels to justify their high capital cost (~$15,000/kW). Electrolysis, by contrast, is interruptible, and runs at a ~40% capacity factor, enabled by a capital cost that is 50 times less per kW than data centers.

**FIGURE 3.** Electricity consumption of data centers and other loads in different scenarios out to 2050. The baseline and current policy scenarios are not constrained by greenhouse gas emissions. The central and central high data center scenarios reach net zero by 2050.

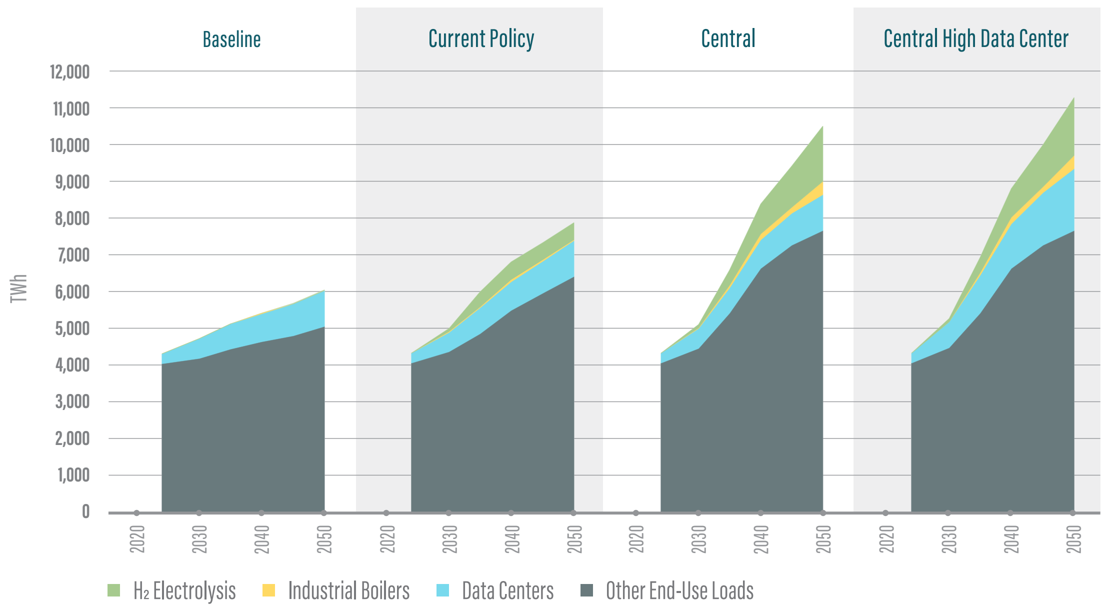



Table 4 shows the incremental capacity requirement per megawatt of data center load in the Central High Data Center sensitivity. Each 1 MW of data center loads requires a combination of renewables for energy (2.72 MW of wind and solar) firm capacity for reliability (0.65 MW of gas generation), plus storage for balancing (0.30 MW). This represents a "systems" solution to the problem of reliable clean electricity for data centers and requires coordination, including the offsetting of emissions from the natural gas that is used to back up energy from wind and solar.[7] Because of delays in satisfying interconnection requests and procuring grid-connected clean resources, hyperscalers (cloud computing and storage providers that can accommodate large and growing demand) may choose to focus on geothermal and nuclear generation on-site. Indeed, such investments are already taking place, as evidenced by Google's recently signed power purchase agreement with small modular reactor (SMR) company Kairos Power.[8] While this strategy will come with higher energy cost, it is a tradeoff that has other advantages, including a cleaner story for compliance with corporate climate commitments.

7 2050 Electricity Sector emissions are 170 Mt in the Central Scenario. Data center's pro rata share of those emissions would be 15.8 Mt resulting in an annual cost of $2.4B assuming a marginal abatement cost of $150/tonne.

8 Google announcement: https://blog.google/outreach-initiatives/sustainability/google-kairos-power-nuclear-energy-agreement/

**TABLE 4.** Incremental generating capacity requirements per megawatt of data center load in Central High Data Center scenario

| Electricity Technology | New capacity (MW) per MW data center |
|---|---|
| **Onshore Wind** | 1.35 |
| **Transmission-sited Solar** | 1.29 |
| **Gas** | 0.58 |
| **Electricity Storage** | 0.30 |
| **Offshore Wind** | 0.08 |
| **Gas w/CC** | 0.07 |
| **Other** | 0.03 |

Figure 4 shows the consumption results of Figure 3 distributed across the different regions of the U.S. Given the assumption that 50% of data center load is free to locate in areas with low energy costs, the figure shows that data centers locate disproportionately in the wind belt where the levelized cost of electricity is lowest. Both the northern and southern area of the wind belt see high data center growth. However, without much spread in clean electricity cost between different places in the wind belt, the best location for this load growth is uncertain and other factors, not represented here, may predominate. The figure also shows a correlation between data center and electrolysis load for hydrogen production. The modeling shows these loads working well in tandem, as the flexibility of electrolysis loads helps enable lower cost electricity for data centers.

**FIGURE 4.** Electricity consumption by region and type of demand in 2024 and 2050 for Central and Central High Data Center scenarios. (Data center consumption is in blue).

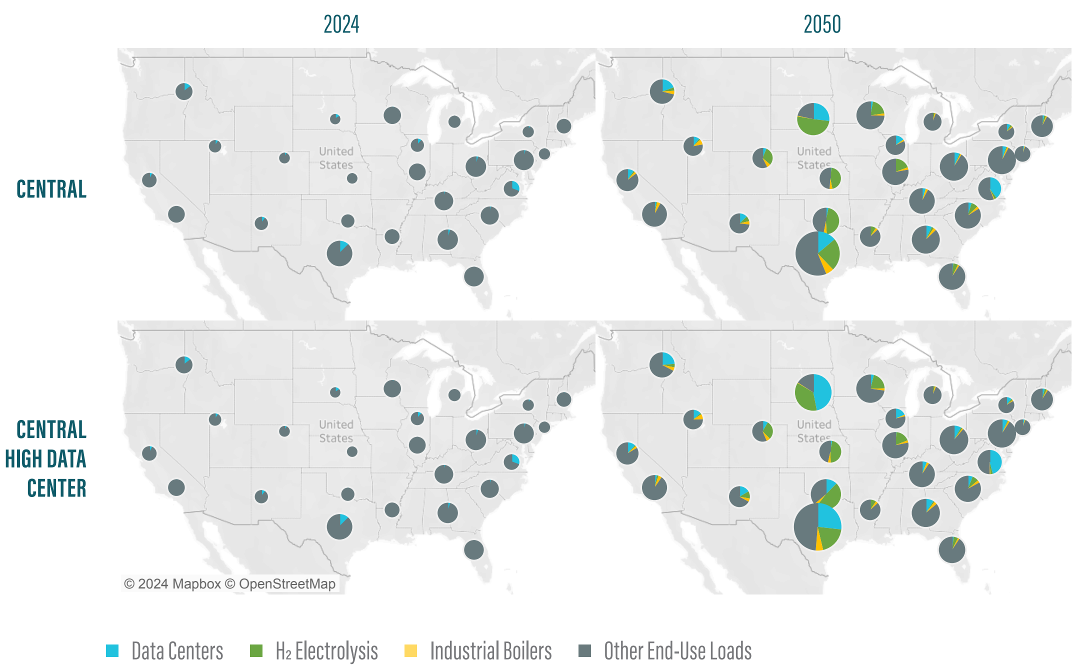
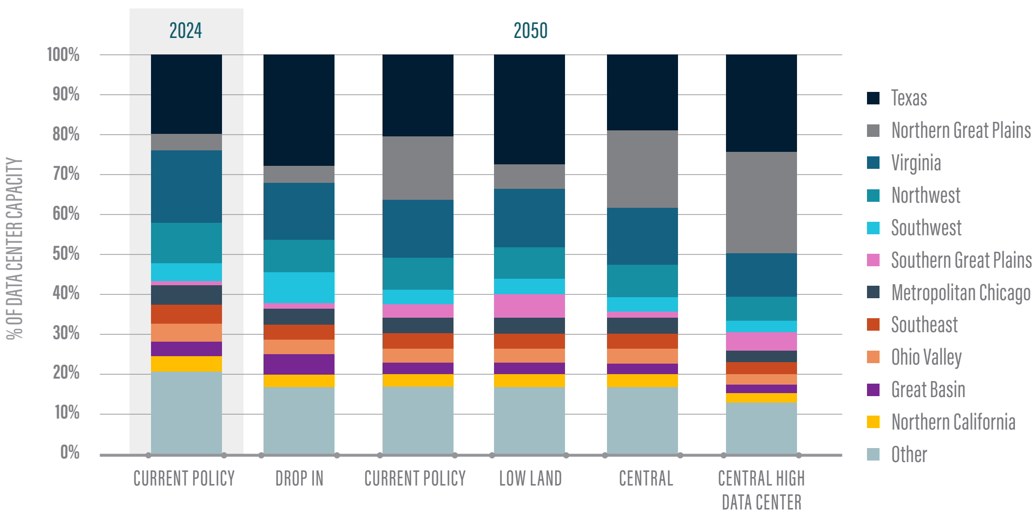


Figure 5 shows the percentage of data center capacity by region across scenarios. In the Central High Data Center sensitivity, under the modeling assumptions described earlier, nearly 50% of data center capacity in 2050 is located in Texas and the northern Great Plains states.

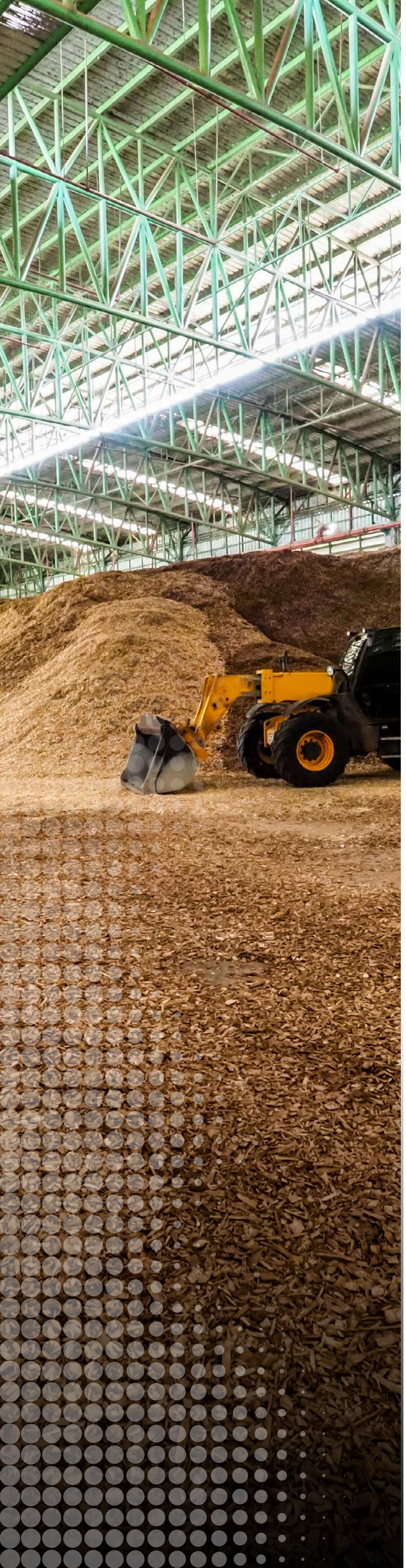
**FIGURE 5.** Share of data center capacity by region across scenarios.




## Geothermal Heat

**Improvement:** A highlight of ADP 2024 is significant new analysis of, and results for, geothermal energy. In earlier ADP modeling, geothermal played a minimal role, falling into the "other" category in electricity generation, as it was not competitive except in a few locations. These results were consistent with prevailing views among researchers and industry: that the main role of geothermal would be in electric power, and that this role would be restricted geographically to locations with high quality near-surface hydrothermal resources, as seen in the familiar geothermal map showing only a smattering of hot spots, mostly in the western U.S.

Technological advances drawn from the oil and gas industry are changing both the resource map and the assumptions about potentially competitive applications for geothermal. The improved drilling technologies that have made the shale gas and shale oil revolutions of the last decade possible are being applied to geothermal. Current state-of-the art methods make it less expensive to drill deeper, which allows for easier access to target resource temperatures; horizontal drilling allows for fewer wells to be drilled to access those resources; and hydraulic fracturing pumps high pressure fluid into the well to open small fractures, which increases subsurface connectivity and flow rates. The new technology, which involves pumping water into an injection well and extracting it from a production well, is sometimes referred to as next-generation

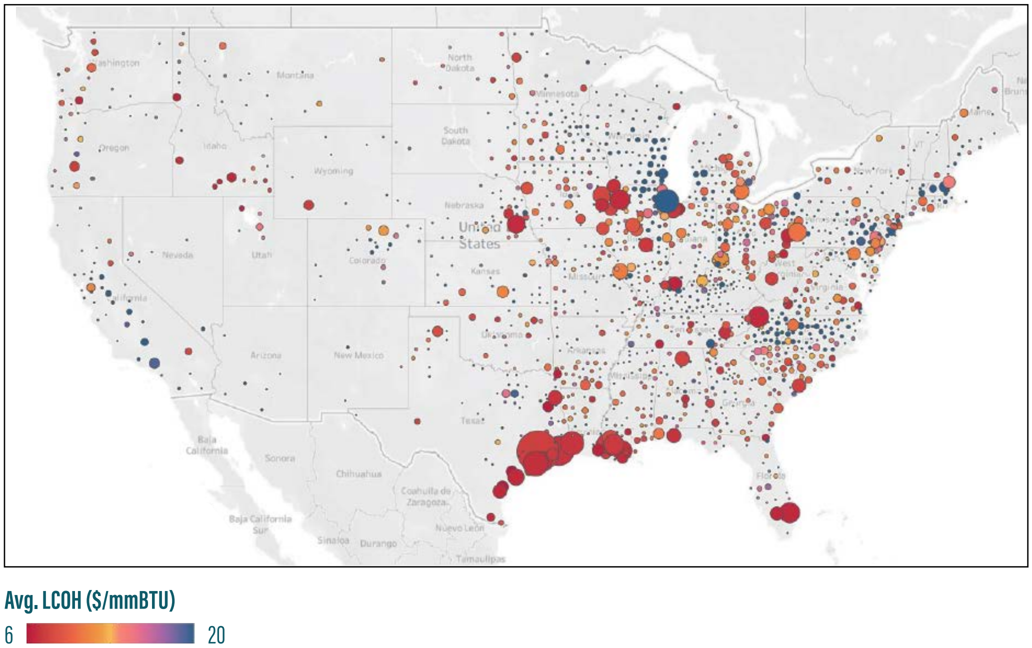


geothermal (NGG). NGG is very different from the advanced geothermal systems envisioned a generation ago, which assumed conventional wells drilled to great depths, not the fracking-based NGG of today.

With new cost assumptions, geothermal is no longer restricted to electricity generation, but is competitive with other resources such as heat pumps, biomass, and thermal energy storage for providing decarbonized thermal energy. One particularly promising application highlighted in *ADP 2024* is industrial steam, a significant contributor to global $CO_2$ emissions when generated through fossil fuel combustion. Indeed, geothermal steam has some important advantages over geothermal electricity. Much of industrial steam supply is at relatively low temperatures (150°C or less, versus 250°C for electricity generation) allowing industry to access a large quantity of resources that are unsuitable for electricity. Moreover, direct use of steam captures most of the energy in the steam, as opposed to ~70% thermodynamic losses in steam turbines. On the other hand, steam is not an easily movable or tradable commodity like electricity, so it must generally be produced and consumed in close proximity.

In preliminary scoping for *ADP 2024*, we combined a national inventory of boilers and cogeneration facilities with a geological map of geothermal resource depth, to calculate the levelized cost of heat (LCOH) across the U.S. and cross-reference it to industrial demand. Based on consultation with the geothermal industry and published documents, EER adopted the advanced geothermal scenario in NREL's *Annual Technology Baseline 2024* as the most representative of the future cost trajectory for geothermal. Our analysis indicates that technological advances have largely decoupled well cost from resource quality, with the upshot that cost-competitive geothermal steam may be reasonably accessed widely across in the U.S., including most of the places where steam is needed. This decoupling also means that LCOH is predominantly influenced by the facility size, rather than resource depth, as economy of scale takes precedence among cost factors (see Figure 6).

**FIGURE 6.** Calculated levelized cost of heat from geothermal steam in the United States assuming Advanced Technology Innovation. Bubble size represents the scale of industrial steam demand at 150°C or less.




To put this in context, we found 2035 LCOH values for geothermal in the range of $7/MMBtu in much of the U.S. Decarbonized heat supply in general has been a dynamic area in ADP modeling, with changing assumptions from year to year highlighting different resources: dual-fuel boilers, heat pumps, thermal energy storage, and now geothermal steam. Any can be a winner under the right circumstances. One potential application of interest is direct air capture (DAC), which can use any heat source to meet its thermal needs. *ADP 2024* modeling overlays county-scale geothermal temperature depth profiles with a supply curve based on optimal considerations for DAC siting to determine where geothermal steam would be most competitive.

**Results:** Figure 7 shows the applications of steam in the U.S. across scenarios, with about half of steam being used in producing bulk chemicals. This use grows over time, while other applications such as food processing and district heating remain roughly constant in most scenarios. Some scenarios with significant amounts of DAC such as the Drop-In and 100% Renewables cases utilize significant amounts of steam that displaces electricity supplied for DAC process heat in previous results.

**FIGURE 7.** Uses of steam across scenarios

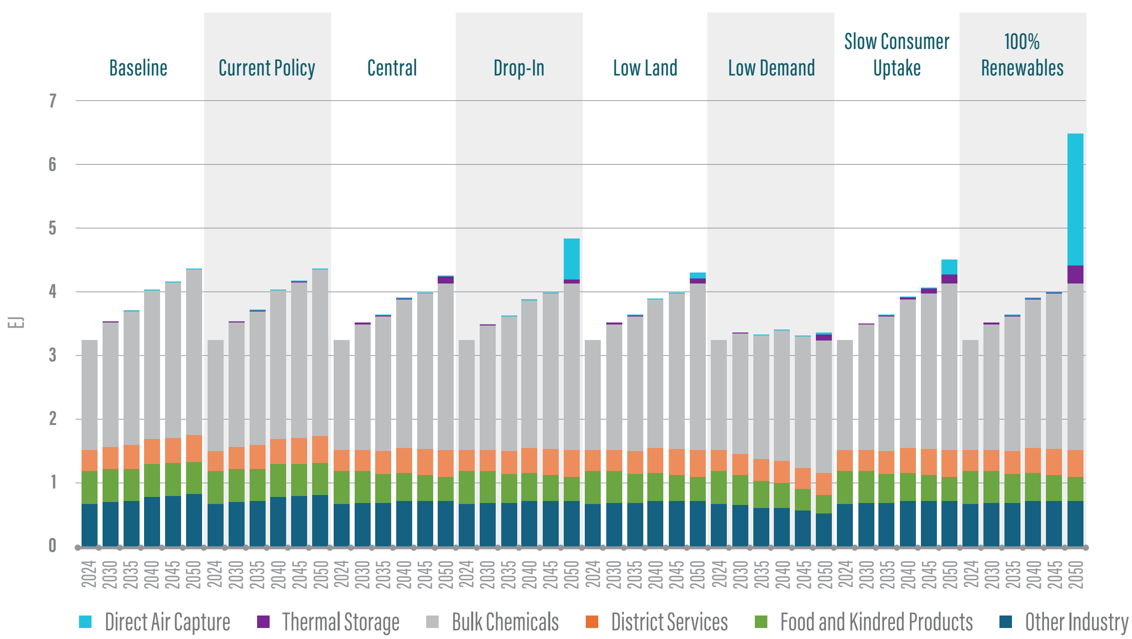
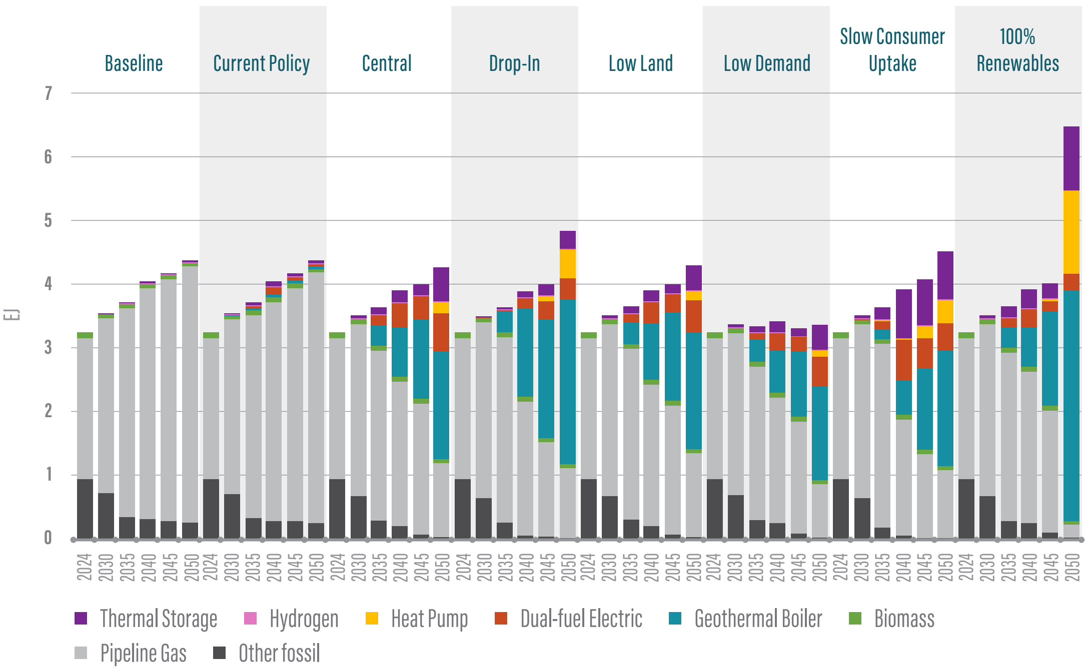



Figure 8 shows the sources of steam supplied to the different applications. The noteworthy result is the rapid growth of geothermal boilers, which starting from zero at present come to constitute 40-60% of steam supply by 2050 across net-zero scenarios. This growth is mirrored by the decline in steam from burning pipeline gas and other fossil fuels, which is displaced largely by geothermal boilers, with smaller contributions from electricity-based heat sources — heat pumps, thermal storage, and dual-fuel boilers — whose relative competitiveness depends on circumstances and geographic location. By 2050 in the Central scenario, more than a third of steam energy comes from geothermal, and less than a third each comes from electricity and from combustion fuels.

**FIGURE 8.** Sources of steam across scenarios




In electricity, *ADP 2024* results (see Figure 26) show that next-generation geothermal is clearly competitive with nuclear and gas with CCS as "clean firm" capacity. The geothermal share of electricity generation merits its own separate category, and no longer falls into "other." Geothermal capacity reaches 45 GW by 2050 in the Central scenario and even higher levels in the Low-Land and Drop-in scenarios (175 GW) in which wind and solar buildouts are limited. This dramatizes the importance of further geothermal development as a "clean firm" backstop technology. From a geographic perspective, most of the geothermal generating capacity in the model results is still built in the western U.S. where the higher temperatures required for power generation are accessible at shallower depths. This result is in contrast to geothermal heat, which has the potential to provide economically competitive steam in all regions because much lower temperatures are required, and therefore shallower drilling depths are possible.

**Prospects:** Project financing is an important challenge for the future of geothermal steam. Geothermal steam systems involve a large upfront cost, in contrast to conventional boilers that are dominated by fuel costs. This means that facilities choosing geothermal systems will be locked into the decision for decades, regardless of how the technological and cost landscape for decarbonized steam may change during that time. This poses a financial risk to companies even when the long-term apparent cost of geothermal is lower than the alternatives. Policy can help to address this concern, as IRA tax incentives are already doing. This caveat aside, however, the fact that the same technology breakthroughs that produced the shale boom of the 2010's are being applied to geothermal steam suggests that it could experience a similar growth trajectory in the coming years and start to play an important role in industrial decarbonization.

## Geologic Hydrogen

**Improvement:** For the first time, *ADP 2024* explores geologic hydrogen as a potentially significant energy source for the U.S. Geologic hydrogen (Geo H2, also known as natural hydrogen or white hydrogen) is extracted from underground reservoirs in a manner similar to oil and gas. Its existence has been known for centuries, but only in the last few years has the possibility of Geo H2 being available in large quantities at reasonable cost been taken seriously by scientists, industry, and policy makers. Interest has soared since a 2018 article in a scientific journal announcing that a well in Mali was producing a stream of greater than 90% pure hydrogen.[9] Two conceptual breakthroughs underlie optimism regarding Geo H2 potential: (1) recognition that the geologic structures and processes that produce H2 are entirely different from those that produce oil and gas, so that earlier observations based on H2 discovered during oil and gas drilling were not indicative of its actual abundance, and (2) that the methods of horizontal drilling and hydraulic fracturing developed by the oil and gas industry are well-suited to extracting hydrogen.

There are a variety of geological processes that produce hydrogen as a reaction product. We describe the two most relevant here. The first is radiolysis, or breakdown of water molecules by radioactive decay in subsurface rocks. The second, which is of greater interest for current prospecting, is chemical reactions involving water in the presence of iron-containing minerals known as ultra-mafic rocks, including the abundant crustal mineral olivine. These are the key inputs to a natural process called serpentinization, which under reducing (low oxygen) conditions, and with sufficient quantity of iron containing minerals in the right oxidation state (iron II), can produce hydrogen in abundance. If hydrogen's escape paths to earth's surface are blocked by impermeable rock layers, and if the hydrogen is not consumed in other biological or chemical reactions, then it can accumulate in reservoirs and be extractable by drilling. Resource assessments currently vary by many orders of magnitude in the scientific literature, but the USGS has publicly suggested ranges from "thousands to millions of megatons, with a mean value in the tens of millions of megatons" of widely accessible Geo H2 globally.[10] For scale, one billion tons of H2 has an energy value roughly equivalent to total U.S. energy use in a year.

In addition to uncertainty about quantity is uncertainty about cost. The economics of Geo H2 production resemble those of oil and gas: land leasing, exploratory and production wells, licensing partnerships. *ADP 2024* finds the cost of producing alternative forms of carbon-neutral H2 (e.g., electrolysis using renewable electricity or methane reforming with CCS) to be in the range of $12-18/MMBtu in 2050 ($1.5/

9 Prinzhofer, A., Cissé, C. S. T., & Diallo, A. B. (2018). Discovery of a large accumulation of natural hydrogen in Bourakebougou (Mali). International Journal of Hydrogen Energy, 43(42), 19315-19326.

10 Statement of Dr. Geoffrey Ellis, Energy Program Lead for Geologic Hydrogen, USGS, Before the Senate Natural Resources Committee, February 28. 2024. https://www.energy.senate.gov/services/files/A4FBB586-D6C6-4E73-BE9C-61128E922DFB. The written transcript has a typo regarding the quantity, but in the oral testimony the magnitude is as stated in the quote above. This was confirmed by Dr. Ellis, *pers. comm.* See https://www.energy.senate.gov/hearings/2024/2/full-committee-hearing-to-examine-the-opportunities-and-challenges-associated-with-developing-geologic-hydrogen-in-the-united-states.

kg – \$2.25/kg). If Geo H2 were to reach \$1/kg (the target of the DOE Earthshot for clean hydrogen[11]) it would not only be cheaper than other forms of H2 production (not counting distribution costs), but it could also compete with natural gas (at \$2.50/MMBtu) given a carbon tax of \$100/tonne $CO_2$. A fundamental reason to think that geologic hydrogen could be competitive with other sources in a decarbonized economy is that the energy required to produce a gas well is more than an order of magnitude lower than the energy required for electrolysis, while producing hydrogen from natural gas adds the cost of carbon capture and storage to the cost of well production. Whether \$1/kg Geo H2 is achievable will be seen in practice, but there are two factors that provide a strong impetus for early development: the U.S. federal 45V tax credit of \$3/kg H2, and the frequent co-existence of helium (He) with Geo H2. Helium is currently in short supply globally, and co-production of He can provide a major early revenue stream for Geo H2 producers. Players ranging from ARPA-E and national labs, to philanthropic donors, to private capital and the oil industry itself, have all provided initial funding for Geo H2 development.

In *ADP 2024* we explored the potential of Geo H2 in a sensitivity analysis. The Geo H2 sensitivity shares all other inputs with the Central scenario but differs in assuming that Geo H2 achieves a production cost of \$1/kg and that up to 10 EJ per year of supply is available at that price in 2050, a quantity lower than upper-end estimates of resource potential but sufficient to demonstrate the potential role of Geo H2 in a decarbonized economy. Growth rates between 2030 and 2050 for geologic hydrogen are based on the rate at which shale gas production in the U.S. increased between 2007 and 2020.

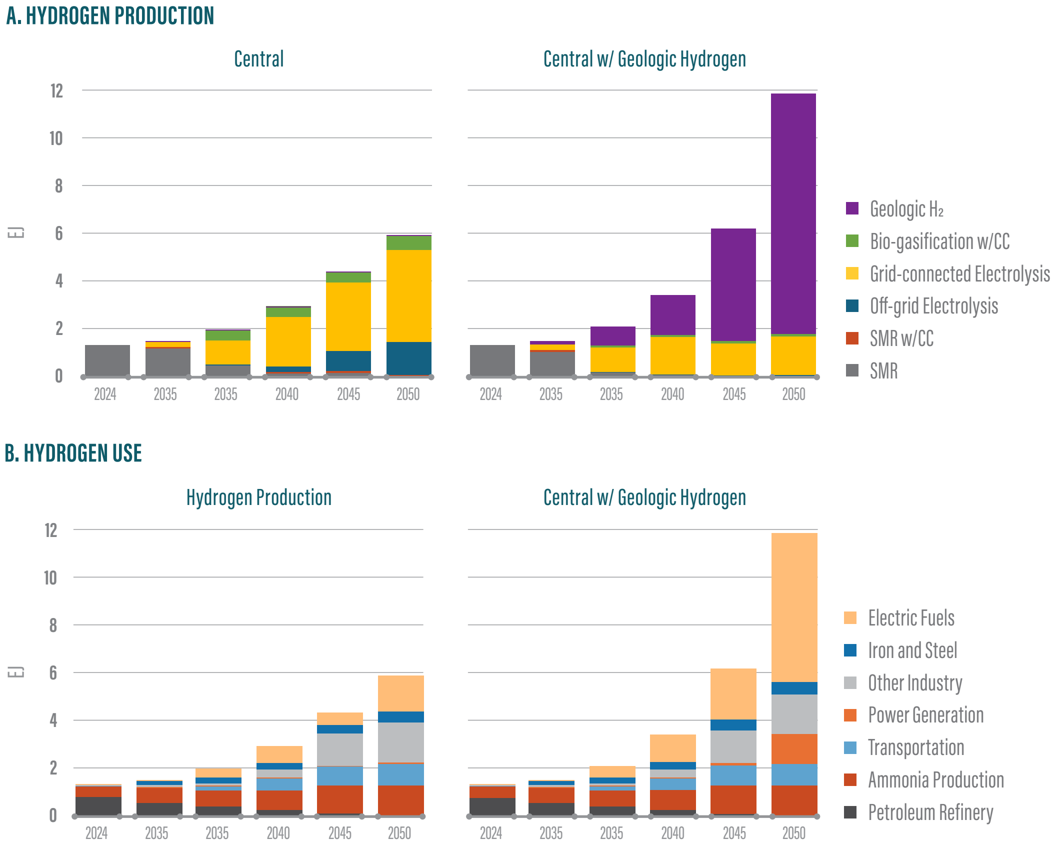
In the absence of adequate data to identify resource potential by location, Geo H2 is assumed to be located across the U.S. in a quantity proportional to the land area of each region. While these assumptions will likely need correction when better data is available, the Geo H2 sensitivity does provide an indication of the potential directional impact of a Geo H2 breakthrough for U.S. decarbonization pathways.[12] Research is currently underway by USGS and others to better estimate where H2 supply is likely to be most abundant, and this work may inform future modeling efforts, including the potential need for H2 pipelines in the development of a Geo H2 industry

**Results:** Hydrogen production in the Geo H2 case is double that of the Central scenario, and Geo H2 comprises more than 80% of production (Figure 9). It displaces two-thirds of grid-connected electrolysis, and almost all bio-CCS hydrogen and off-grid electrolysis in energy parks where e-fuels are produced. It also hastens the decline of steam methane reforming (SMR), the main method by which hydrogen is currently produced in the U.S., and one that emits $CO_2$ to the atmosphere in the absence of CCS. Geo H2 starts to displace SMR hydrogen as early as 2030.

11 https://www.energy.gov/articles/secretary-granholm-launches-hydrogen-energy-earthshot-accelerate-breakthroughs-toward-net

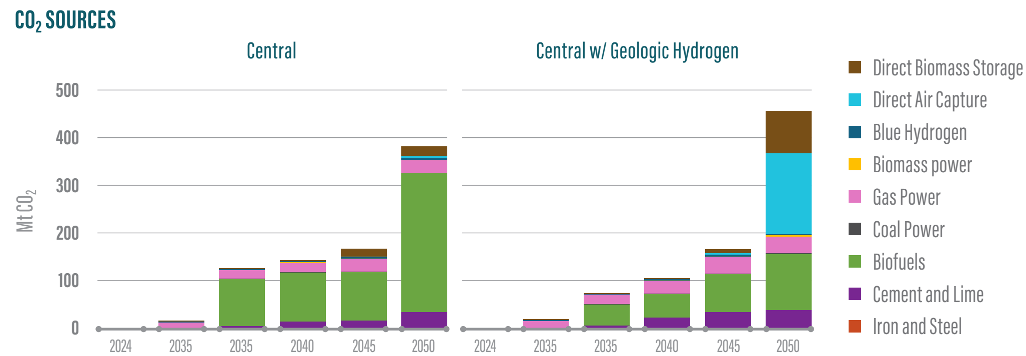
12 Actual geologic distribution is likely not to be uniform as assumed in this analysis. Based on current maps, the distribution of mafic rock in the U.S. is concentrated in certain locations. Furthermore, the conditions for a hydrogen reserve to exist requires additional geological attributes, namely effective reservoir and trapping layers. Nonetheless, publicly available sources do not justify more geographic specificity than uniform distribution at present.

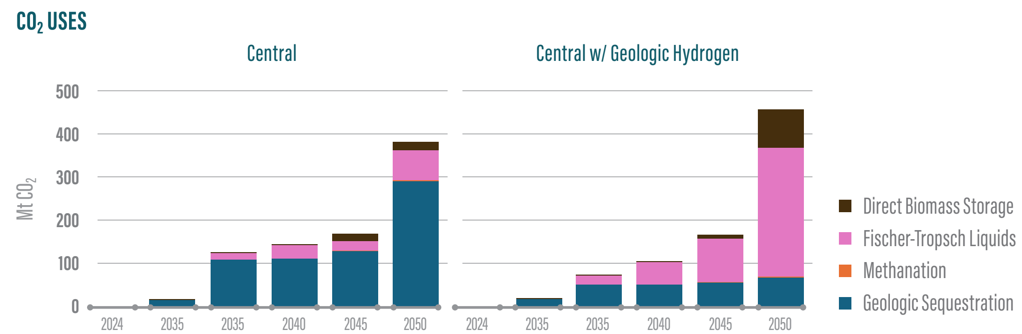
**FIGURE 9.** (Top) Hydrogen production by type in the Central and Geo H2 scenarios out to 2050 (Bottom) Hydrogen demand by end use in the Central and Geo H2 scenarios out to 2050




On the demand side, the main effect of low-cost Geo H2 is a large increase in synthetic fuel production. Hydrogen used for this purpose increases by a factor of four, from less than 1.5 EJ per year in 2050 to almost 6 EJ. It also results in hydrogen becoming a significant fuel for electricity generation, displacing some natural gas, compared to minimal use in the Central scenario.

**FIGURE 10.** (Top) $CO_2$ sources in the Central and Geo H2 scenarios. (Bottom) $CO_2$ uses in the Central and Geo H2 scenarios




A corollary of the Geo H2-driven increase in synthetic fuels is increased demand for $CO_2$, the other primary input material (Figure 10). $CO_2$ capture for utilization in fuel production quadruples in the Geo H2 scenario, from 75 Mt in the Central scenario to more than 300 Mt. Direct air capture (DAC), which is minimal in the Central scenario, becomes the largest single source of $CO_2$ at 180 Mt, displacing a comparable amount of $CO_2$ from biofuel production with CCS, which falls from 290 Mt to 110 Mt in the Geo H2 scenario. Further, the high utilization of captured $CO_2$ in fuel synthesis, combined with displacement of some fossil fuel use by hydrogen, is reflected in a dramatic decrease in geologic carbon sequestration compared to the Central scenario, falling from 290 Mt/y to 60 Mt/y.

A further important result of the Geo H2 sensitivity is a significant decrease in land requirements for energy. Reducing grid electrolysis and biomass use saves land required for wind and solar installations, transmission lines, and bio-energy crops. The close relationship between Geo H2 and biomass is noteworthy: biomass use decreases by 2.5 EJ, mostly in the form of herbaceous energy crops, reducing land requirements. Overall land use for energy in the Geo H2 sensitivity decreases by 18%, from 77 million hectares in the Central scenario to 63 MHa (Figure 11).

**FIGURE 11.** Land use saved in the Geologic Hydrogen Scenario by year

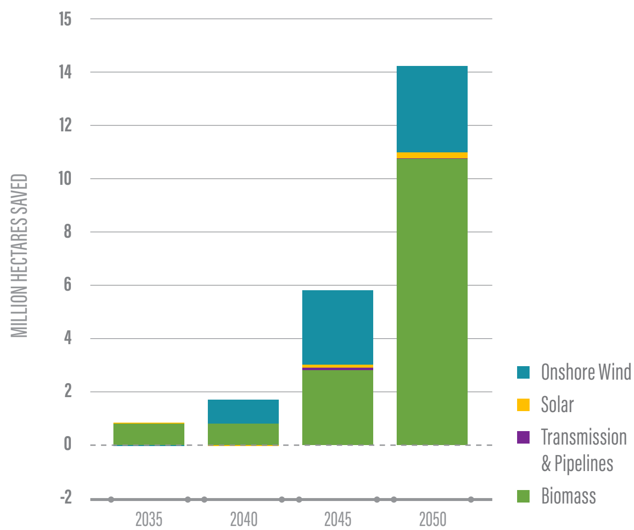
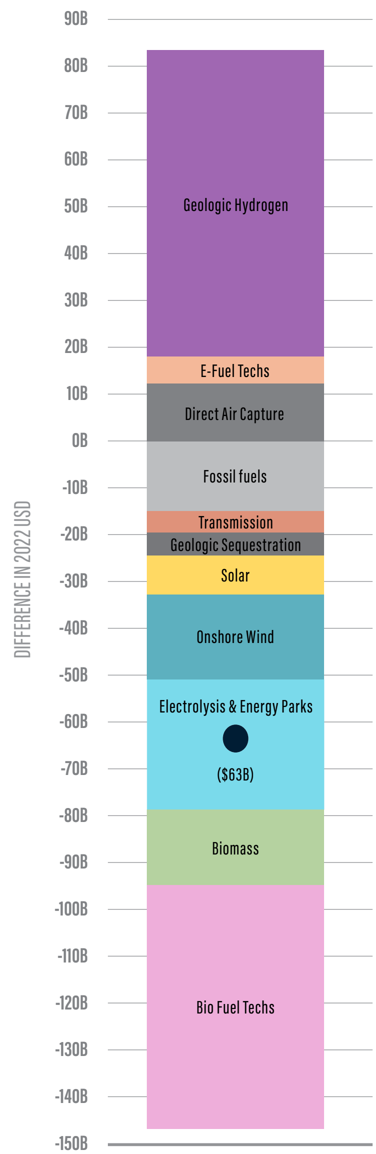



**FIGURE 12.** Net cost of geologic hydrogen in 2050. Bars show the costs and saving of the Geo H2 scenario compared to the Central scenario. The circle shows the net benefit (negative net cost).




A final important finding is that Geo H2 lowers the overall economy-wide cost of reaching net-zero by $63B in 2050 compared to the Central scenario (Figure 12). Putting this in terms of unit energy cost, Geo H2 at $1/kg costs $7.6/GJ, but its use leads $13.9/GJ in savings for avoided fossil fuels, solar and wind installations, transmission, biomass, biofuel production, electrolysis, and energy parks. The result is a net cost savings of $6.3/GJ for each GJ of Geo H2 used, not including the value of reducing land impacts.

While the distribution of economically extractable Geo H2 across the U.S. remains unknown and the technology is still in its early days, this analysis shows that the potential of Geo H2 to become an important component of a net-zero energy economy in the U.S. is such that further work is strongly warranted.

## Cement

**Improvement:** *ADP 2023* focused on reducing emissions from cement production in two ways: (1) replacing high-carbon heat sources for cement kilns with low-carbon sources, and (2) using CCS to capture residual energy emissions and also process emissions, mostly from the calcination of limestone (turning it into lime, in the process emitting $CO_2$) at very high temperatures. The most significant change in *ADP 2024* is the substitution of alternative materials for clinker, the principal component of Ordinary Portland Cement (OPC) and the source of most $CO_2$ emissions in the cement-making process. As a result, while overall U.S. demand for cement increases slightly out to mid-century consistent with current forecasts, in *ADP 2024* scenarios OPC clinker demand decreases over the same time period.

Of the alternative cement formulas currently being investigated, we found the most competitive at large scale to be Limestone and Calcined Clay Cement (LC3) in which a mix of crushed limestone, low-grade kaolinite clay, and gypsum replaces 50% of the OPC clinker. This mixture avoids about half of OPC process emissions per tonne of cement, and also reduces energy emissions because clay calcining is done at 800° C compared to 1450° C for OPC clinker. LC3 has several advantages over competing approaches: (1) it has identical structural properties to OPC, facilitating acceptance in the cement industry; (2) it uses widely available, inexpensive materials; and (3) the necessary equipment can be inexpensively installed or retrofitted at existing plants.

In order to more accurately compare costs between LC3 and conventional clinker, a further improvement in *ADP 2024* is incorporating the cost of cement-making inputs such as limestone, clay, and gypsum. With material costs accounted for and given lower energy costs due to lower process heating requirements, adoption of LC3 potentially reduces the cost per ton of cement while also reducing emissions. This makes it a first-choice decarbonization option not only in the U.S. but also in low and middle-income countries, where the majority of cement production is expected to occur in the years ahead. Several large-scale cement plants have already been retrofitted to LC3 in Africa, Latin America, and South Asia. In the U.S., 3 out of the 6 projects chosen for funding support by the DOE Office of Clean Energy Demonstration will produce LC3 (Lebec Net Zero, Roanoke Cement, and Summit Materials).

While LC3 can dramatically reduce the share of clinker in cement, clinker must still be produced, and its $CO_2$ emissions must be captured in a net-zero scenario.[13] We continue to view oxyfuel CCS and direct separation CCS (trade name LEILAC) as the most promising long-term carbon capture technologies for cement. Both of these approaches produce highly concentrated $CO_2$ streams, greatly reducing the energy requirements of regenerating the capture medium (e.g. liquid solvents). In both cases, the relative purity of the $CO_2$ stream means that high capture rates (>90%) can be achieved using recycled heat alone, whereas conventional liquid solvent CCS may require adding a natural gas

13 Other proposed measures to reduce demand for OPC clinker and its resulting emissions, such as changes in concrete mixing practices and building design, were not modeled here.

cogeneration plant to provide the additional heat needed for regeneration above a ~50% capture rate, according to industry sources.

In *ADP 2024* modeling we have delayed the initial availability of LEILAC at scale until after 2035, to reflect that scale-up projects are more advanced in Europe than the U.S.[14] For oxy-fuel CCS, while technical challenges remain in sealing rotating kilns from air leakage (“false air”) that dilutes the $CO_2$ concentration of the effluent, it appears that sufficient progress is being made, especially in Germany, to maintain initial availability at scale before 2035. The combination of oxy-fuel CCS with biomass-based fuels represents a cost-competitive option for a negative emissions technology in cement.

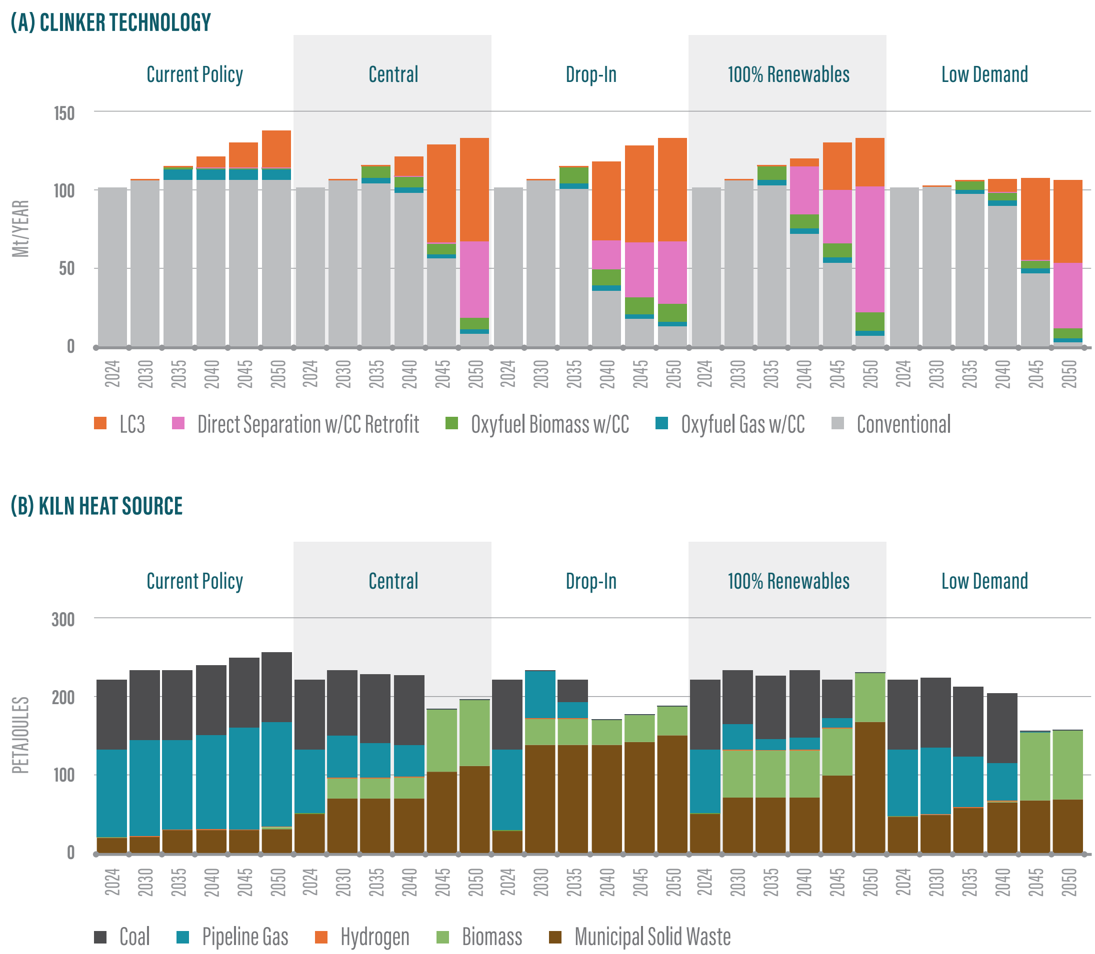
A final set of changes in *ADP 2024* reflect two findings of a recent DOE report regarding U.S. cement industry economics. (1) Cement producers typically rely on balance-sheet finance rather than conventional project finance. Accordingly, *ADP 2024* financing assumptions have been changed to reflect equity financing and the need for shorter payback times. (2) Downtime is seen as extremely costly by owners of cement plants, which typically have very high utilization factors. To reflect this, we have added downtime costs for CCS retrofits of existing plants.

**Results:** *ADP 2024* cement results look substantially different from those in *ADP 2023*, which is not surprising given the changes described above. Figure 13 illustrates three important findings. First, LC3 limestone and calcined clay displace 50% of clinker output by 2050 in all net zero cases. Second, direct separation CCS (LEILAC) retrofits of existing kilns are competitive and comprise the majority of CCS in most cases. Third, where economy-wide gross $CO_2$ emissions are highest, the combination of oxy-fuel CCS with biomass-based fuels is a cost-competitive option for a negative emissions technology. This is especially notable in the Drop-in and Slow Consumer Uptake scenarios. In *ADP 2023*, oxyfuel BECCS did not appear until 2050, but with new assumptions in the current analysis it appears in 2030.

To illustrate these in a single case, in the Central scenario overall production increases from about 115 Mt today to 127 Mt in 2050, but production of conventional OPC clinker decreases to half of that amount, or about 64 Mt. 50 Mt of this clinker is produced with direct separation CCS, while another 10 Mt is produced with oxyfuel BECCS.

14 Industry sources have attributed this to a decision by Calix, the relatively small Australian company that developed LEILAC, to focus its limited resources on Europe, where there is a more receptive market and policy environment for cement decarbonization. This situation could change if LEILAC were to receive more attention in the US. Notably, however, none of the cement decarbonization projects selected by DOE OCED were LEILAC projects.

**FIGURE 13.** (Top) Clinker technology by type across scenarios (Bottom) Energy source for cement kiln heat




# Biomass

**Improvement:** In 2024, the U.S. Department of Energy released an updated report on biomass supply potential in the United States (the 2023 Billion Ton Report, or "BT23"), the latest in a series of reports on this topic that began in 2005.[15] In previous editions of the *ADP*, EER used the 2016 edition of the Billion-Ton Report for biomass feedstock data. In *ADP 2024*, we have used the new update which introduces new biomass feedstock categories, such as intermediate oil seeds and forest thinnings from Western forests. Given that Western forest feedstocks are featured only as a case study, we supplemented BT23 with data from the 2024 Roads to Removal study by Lawrence Berkeley National Lab.[16] This study identifies higher feedstock potential from Western forests as a result of plans for increased forest thinning for wildfire prevention.

15 DOE Billion Ton Report Update (2024). https://www.energy.gov/sites/default/files/2024-03/beto-2023-billion-ton-report_2.pdf
16 LBNL Roads to Removal (2024). https://roads2removal.org/

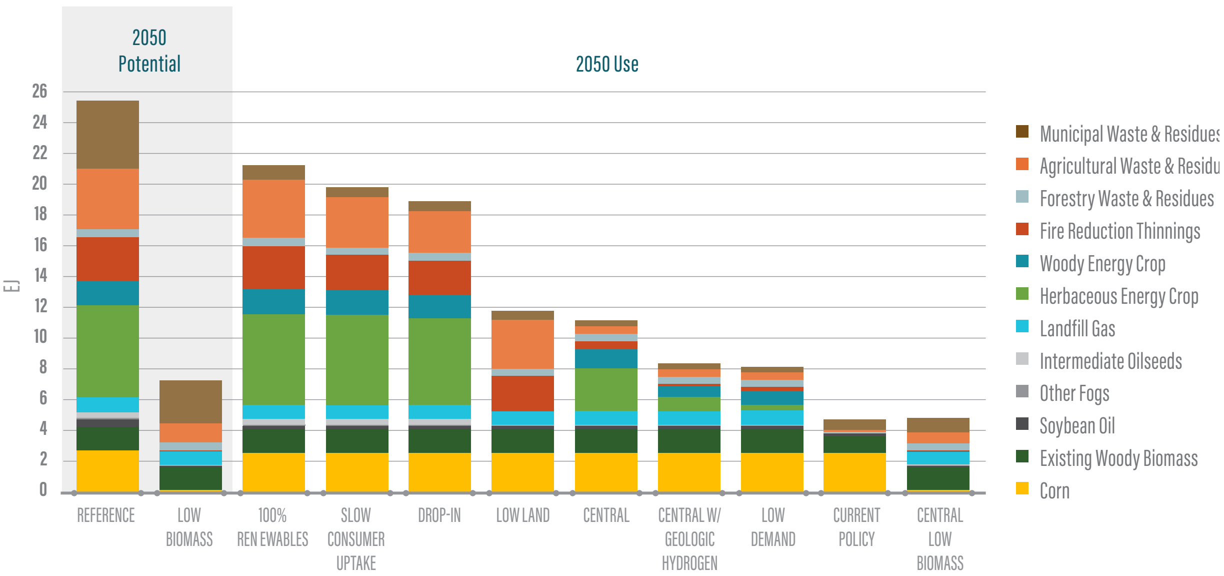
Beyond the expanded feedstock categories, *ADP 2024* incorporates several recent advances in biomass technologies. First, we have added a form of permanent biomass storage called "wood vaulting," an application that can achieve negative emissions at lower cost, though it does not produce energy co-products. Second, biogas production and utilization pathways are now explicitly represented in our models, including anaerobic digestion and biogas upgrading for pipeline blending. Previously, these options were treated purely as commodities without the associated need to build capacity for their production. Third, additional costs of $7/MMBtu have been added when bio-oil is used in existing refineries, better reflecting the pre-treatment costs necessary for outputs from biomass pyrolysis to be used as a drop-in replacement for petroleum oil.

Finally, a new sensitivity analysis was conducted in *ADP 2024* to examine energy system trade-offs associated with biomass supply potential. This sensitivity assumes that all purpose-grown energy crops are eliminated by 2050 and applies the "mature market low" projection from BT23 to all other feedstocks, creating the most restrictive biomass supply scenario within a net-zero framework for the United States to date.

**Result:** The inclusion of additional feedstock categories increased total biomass potential in *ADP 2024* scenarios by 1.5 EJ compared to the previous year. Nonetheless, biomass use in the Central case declined by 2.85 EJ to 11.15 EJ this year. This reduction can be attributed to several factors, including a slight increase in electrification, an increase in the baseline land $CO_2$ sink, and increased competitiveness of electricity-derived fuels. In the Central scenario, the primary feedstocks utilized are corn, switchgrass, and miscanthus. Although cost-effective, these feedstocks use a significant amount of land.

The Low Land Scenario explicitly disallows expanding biomass land use beyond current levels, resulting in a preference for feedstocks from agricultural waste, residues, and forest thinning for wildfire prevention over new energy crops. The Low Biomass sensitivity (applied to the Central scenario) takes the additional major step of eliminating the use of existing cropland for biofuels. This sensitivity results in some 5 EJ of biomass use, about the same level of bioenergy as today, but with a very different mix of feedstocks. Feedstock potential and feedstock use by scenario in 2050 are shown in Figure 14. All scenarios use the "Reference" potential except for the Central Low Biomass sensitivity, which uses the "Low Biomass" potential. In this sensitivity, not all possible wastes and residues in the Low Biomass supply curve were used, as many (such as municipal and agricultural wastes) are quite costly. The RIO optimization finds it preferable to use direct air capture or hydrogen rather than higher-cost biomass supplies to produce the same energy system outcomes.

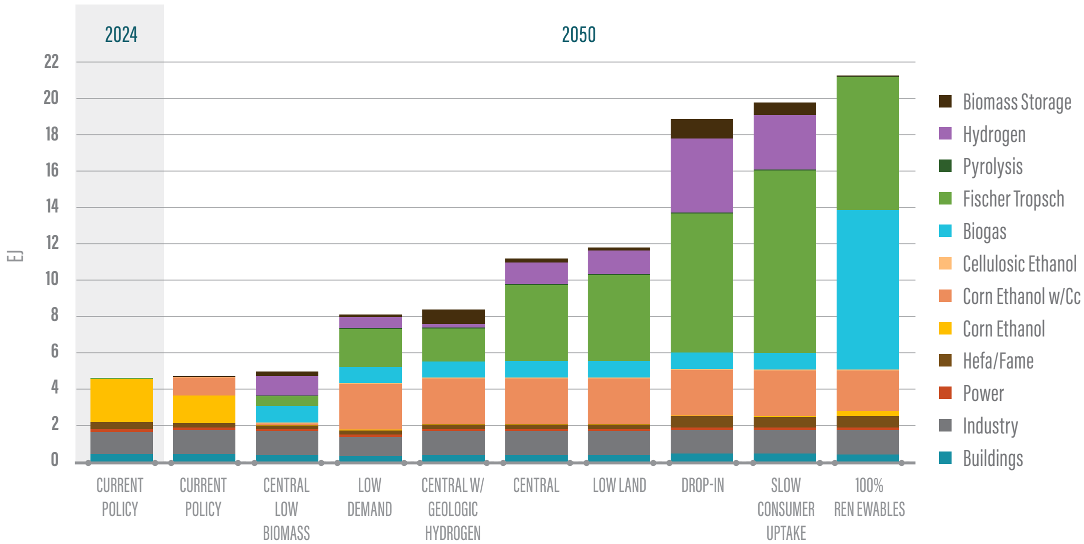
**FIGURE 14.** Consumption of biomass in 2050 by Scenario and feedstock category




Biomass applications in 2050 are shown in Figure 15. In all scenarios except for 100% Renewables, biomass use for liquid fuel production dominates, primarily through ethanol, Fischer-Tropsch, and HEFA pathways. The production of liquid fuels is preferred across all scenarios, as displacing petroleum is more valuable on an energy basis than displacing natural gas. Only in the 100% Renewables case, in which natural gas is eliminated by definition, is a significant amount of biogas produced as well. The higher cost of pyrolysis associated with bio-oil used in this year's analysis resulted in a minimal uptake of this technology. This resulted in more retirements of existing oil refineries in favor of Fischer-Tropsch facilities.

Hydrogen production consumes 11% of biomass in the Central case, mostly in zones with lower quality wind resources (and therefore higher cost electrolysis), such as the southeast U.S., or in zones with plentiful low-cost carbon sequestration potential and large industrial demand for hydrogen, such as Texas.

**FIGURE 15.** Biomass applications in 2050 by scenario




The importance of utilizing the carbon in biomass efficiently is demonstrated by the fact that that the model calls for all biofuel technologies in net-zero scenarios to be equipped with carbon capture. The captured carbon is either recycled into further liquid fuel production or sequestered.

Direct biomass storage provides a secondary application that contributes 20-100 Mt in negative emissions, depending on the scenario. This outcome is highly sensitive to assumptions regarding the cost of permanent biomass storage. We used landfill tipping fees as a proxy for wood vaulting costs, which have risen in recent years and exhibit significant regional variability. This assumption is likely conservative since biomass designated for storage typically has low moisture content, poses minimal risk of leachate contamination, and does not generate methane through anaerobic decomposition.

## Residential Building Shell

**Improvement:** The modeling of residential buildings in the *2024 ADP* adds significant new capabilities in the area of building energy efficiency. In earlier ADP modeling, the treatment of building shell energy efficiency potential was relatively coarse and derived from inputs to the AEO NEMS model with a granularity of Census Division, and without detail on components of building shell upgrades. In *ADP 2024*, the modeling combines a higher resolution representation of residential building stock with data from the National Renewable Energy Laboratory (NREL). The result is a highly granular analysis of the impact of different building shell efficiency measures across building types (e.g., single-family, multifamily, mobile home), construction, vintages, and climate zones.

To create the inputs to EER's EnergyPATHWAYS model, we synthesized two NREL building data products. The 2024.1 release of the ResStock dataset provides a statistical representation of the U.S. residential housing stock containing 2.2 million modeled dwelling units, on top of which NREL modeled the service demand impact of over two hundred different building energy upgrades on each of these representative units. The cost data for energy efficiency upgrades is taken from the National Residential Efficiency Measures Database (REMDB). Given the bespoke nature of building shell retrofits, each modeled residential building has a unique cost associated with each retrofit package. To evaluate the role of building shell retrofits in achieving net-zero emissions, the *ADP* focuses on the advanced retrofit package, which combines the efficiency upgrade packages in Table 5.

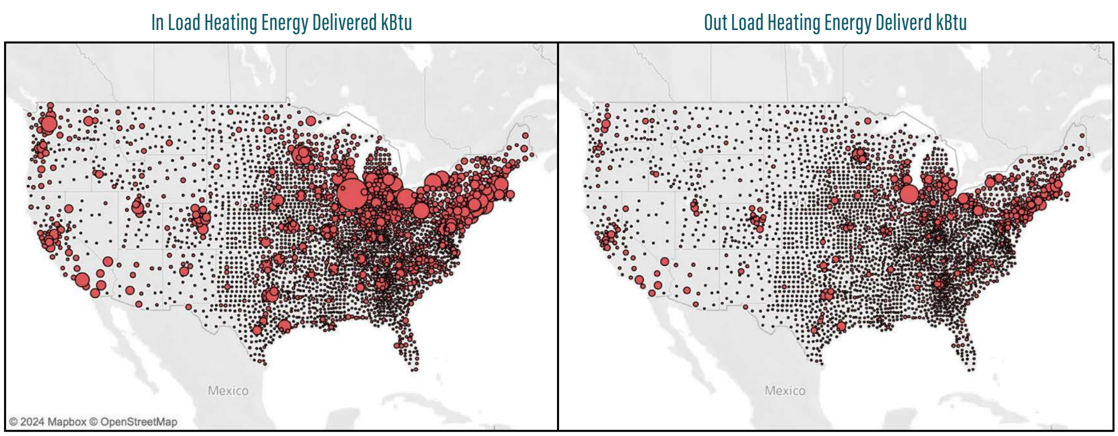
**TABLE 5.** Residential building shell efficiency measures used in ADP 2024.

| Name | Description |
|---|---|
| **ENERGY STAR Windows** | Replace any less-efficient existing windows with windows that meet ENERGY STAR (v7) criteria. |
| **Attic Floor Insulation** | Increase attic floor insulation to IECC-Residential 2021 levels for dwelling units with vented attics and any lower level of insulation |
| **Duct Sealing** | Duct sealing to 10% leakage and R-8 duct insulation for any leakier or less-insulated ducts |
| **Drill-and-fill Wall Insulation** | Drill-and-fill wall insulation (R-13) for dwelling units with no wall insulation and wood stud walls |
| **Foundation Wall and Rim Joist Insulation** | Add R-10 interior insulation to foundation walls and rim joists in conditioned basements and crawlspaces; seal crawlspace vents |
| **Exterior Continuous Wall Insulation** | 1" exterior insulation to foundation walls and rim joists in conditioned basements and crawlspaces; seal crawlspace vents |
| **IECC 2021 Air Sealing** | Improve dwelling unit infiltration to IECC 2021 air sealing requirements |
| **Roof Insulation** | R-30 insulation for less-insulated finished attics and cathedral ceilings |
| **Improved Ventilation** | Energy recovery or exhaust-only ventilation added to dwelling units depending on climate zone and ACH50 values. |

**Result:** Our screening analysis affirmed four aspects of building shell efficiency that are well-known to experts in the field: (1) The installation of more energy-efficient windows is the largest single component of building shell retrofit package cost. (2) Reductions in service demand from a given building shell retrofit package are in general different for heating loads as opposed to cooling loads. (3) While the average cost of different retrofit packages (as a function of floor space, in $/sqft) tends to be relatively similar across the U.S., the impacts of these packages on service demand vary widely as a function of building location due to differences in climate and building codes. (4) An important factor in cost-effectiveness is building vintage: simply put, older structures have more room to improve from a given efficiency upgrade than newer structures, so upgrades of older structures are generally more cost effective.

The rate at which upgrades occur has a large effect on building energy outcomes. In all of our scenarios, we assumed a 1% per year replacement rate for building stock. For the net-zero scenarios, we assumed replacement with the Advanced Building Shell package at increasing rates until 2035, after which all buildings receive this upgrade. For the Current Policy scenario, we assumed ~40% of upgraded buildings receive the advanced package until 2033 when all building shell replacements revert to the reference 2010 standard. Because of the slow replacement rate assumed in the modeling, only a minority of building shells — about 1/3 — are upgraded by 2050 across the scenarios. The potential for service demand reductions, as indicated in Figure 16, is very large, particularly in the Northeast for heating. Although costs are significant, there is an important opportunity for targeted retrofit programs, especially for older buildings in cold climate zones that needs further exploration, including research on accelerated building shell replacement.

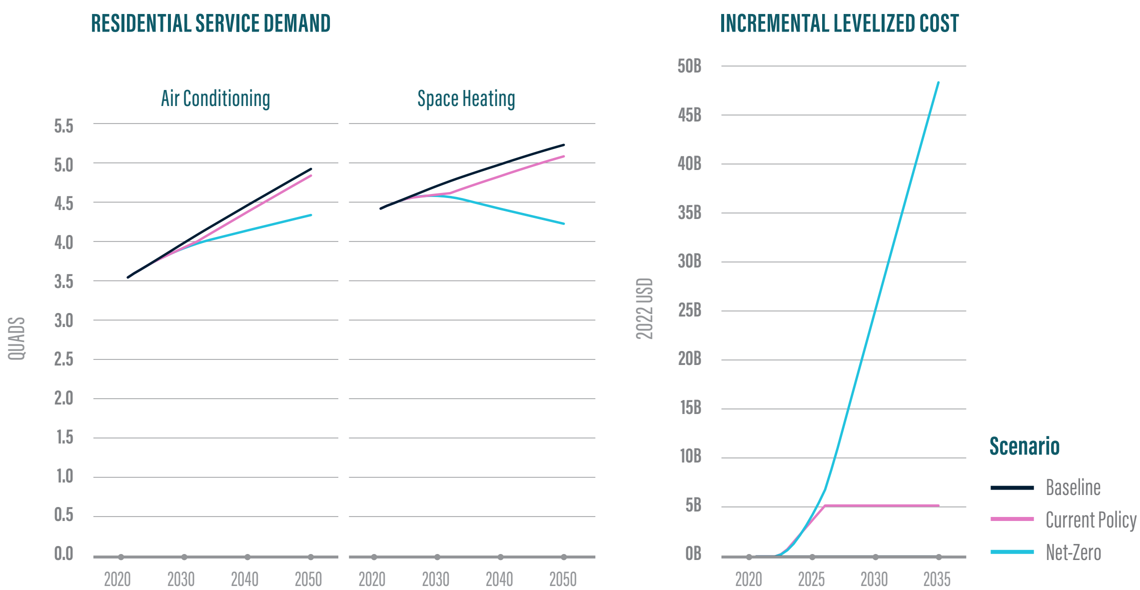
**FIGURE 16.** Technical potential of heating load reduction due to building shell retrofit by U.S. county. (Left) Pre-retrofit heating load (proportional to circle size) (Right) Post-retrofit heating load.




The replacement of one-third of residential building shells by 2050 with high efficiency upgrades in the net zero scenarios results in reductions in residential service demand for air conditioning and heating of 12% and 19% respectively, in 2050, at an incremental annual cost of $48B/year. Figure 17 shows these trends over time. Changes in service demand also reflect growth in residential floor area and changes in climate (represented by cooling and heating degree days), which vary by state based on trends in climate data over the last century. As indicated by a comparison of the space heating and air conditioning figures, annual cooling degree days increase faster than annual heating degree days because of expected climate change.

Note that service demand and energy demand can be very different due to the efficiency of heating and cooling equipment. The thermodynamic advantages of heat pumps and air conditioners mean that service demand can be satisfied with 3-5 times less electrical energy than indicated by thermal energy service demand. As a result, energy demand for air conditioning today is much lower than for heating, and future energy demand for heating will decrease as the penetration of heat pumps increase.

**FIGURE 17.** Residential HVAC service demand after building shell upgrades and the associated costs



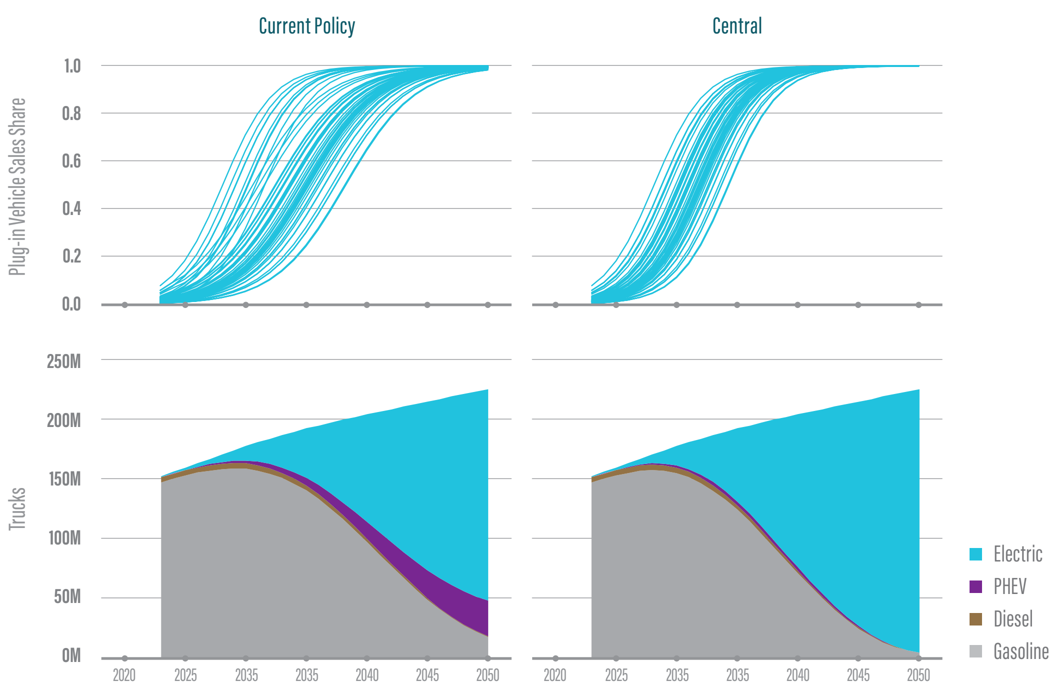

## Transportation

**Improvement:** On-road transportation subsectors have been updated to use the MOVES database. This database includes state level stock and service demand and provides transportation subsectors additional to those in the Annual Energy Outlook, the source of transportation data in *ADP 2023*. This year's update also includes new cost data published by the International Council on Clean Transportation (ICCT). Finally, recent research differentiating customer adoption by state has been used to generate scenarios that better reflect recent trends in EV adoption in different parts of the U.S.

**Result:** Use of the MOVES database has improved the benchmarking of EnergyPATHWAYS, particularly for the published state-level outputs. Important updates to vehicle data in the modeling include a reduction in the capital cost of electric vehicles, due to more rapid cost declines in batteries than previously forecasted. These declines in vehicle capital cost have been somewhat offset by costs of additional vehicle charging infrastructure. Still, overall demand-side costs for EVs have declined compared to *ADP 2023*. With the vehicle data updates, we have also re-examined the split between battery electric and fuel cell adoption assumptions. This year we have further decreased the assumed share of fuel cell vehicles across on-road transportation, reflecting a widening technology gap between these two vehicle technologies. Even if fuel cell or hydrogen combustion technologies catch up to battery electric vehicle technology, the difficulties of deploying adequate hydrogen refueling infrastructure in the U.S., combined with the early adoption lead that battery electric vehicles currently enjoy, makes it appear less and less likely that fuel cells will gain traction outside of niche applications.

Finally, the result of the differentiated state-level adoption for light-duty trucks is shown in Figure 18. Each line in the top panel represents a different state's adoption trajectory for plug-in vehicles. The Current Policy scenario reflects the impacts of IRA tax credits, a decline in battery costs, but most importantly in the long run, the impact of the latest EPA CAFE standards. In this scenario, state adoption rates vary widely in the early 2030s with states like California at a 90% sales share while other states like North Dakota have only a 10% sales share. By 2050 these sales shares all reach near 100% but with a larger fraction of overall sales remaining plug-in hybrids. The Central scenario has a smaller spread between states (though the same relative ordering) and a faster convergence on 100% plug-in vehicle sales than Current Policy. This is sufficient to electrify almost the entire vehicle stock by 2050.

**FIGURE 18.** Light-duty truck sales shares for plug-in vehicles by state and national vehicle stock by technology



# IV SUMMARY OF RESULTS

The high-level results of this analysis are described below, organized into four sections: emissions, energy system, electricity balancing, and costs. Additional results are provided in the Supplemental Results section at the end of this report and in the section comparing *ADP 2024* to results from prior years.

## Emissions

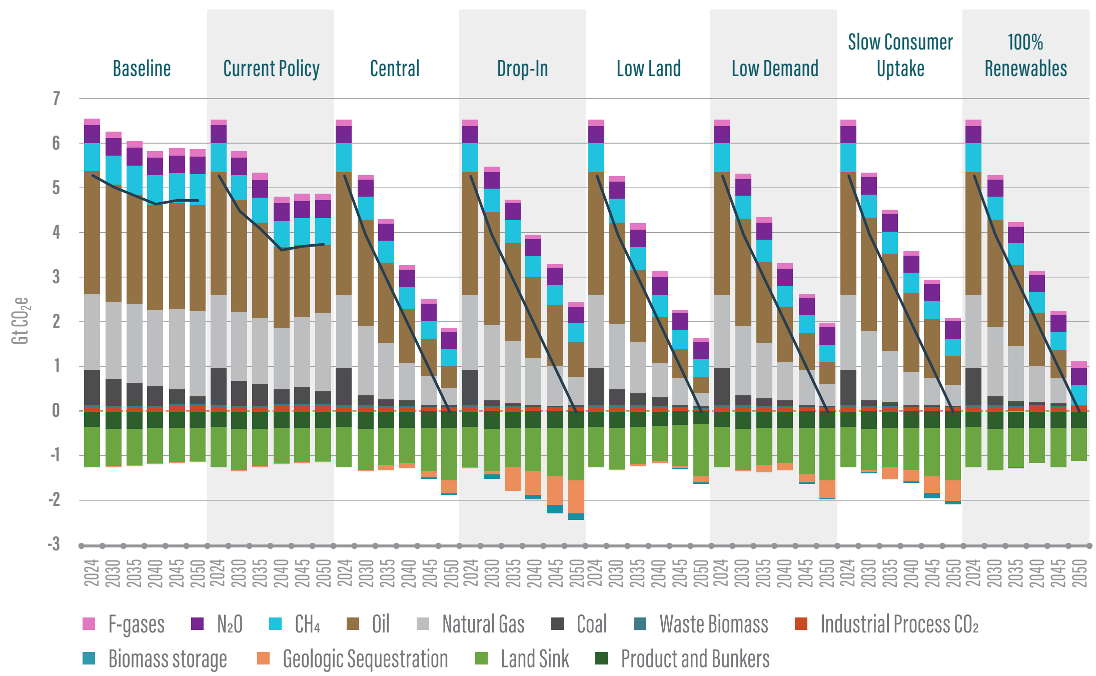
Emissions for each scenario are shown in Figure 19. All net-zero pathways are designed to follow a straight-line trajectory to achieve net-zero emissions by 2050. In the Current Policy scenario the combined effects of the Inflation Reduction Act and the Infrastructure Investment and Jobs Act reduce projected annual emissions from 4.65 gigatonnes in the baseline to 3.62 gigatonnes by 2040.

Also in the Current Policy scenario, all captured $CO_2$ is combined with hydrogen from electrolysis to produce synthetic fuels. This approach is favored due to the 45V tax credit for hydrogen production, which promotes large-scale hydrogen applications, particularly in hydrocarbon fuel production. In net-zero scenarios where geologic sequestration is permitted, sequestration volumes range from 300 Mt in the Central Scenario to as much as 750 Mt in the Drop-In Scenario. Additionally, direct biomass storage contributes between 20 Mt and 100 Mt of negative emissions, further aiding in emission reduction.

The land sink decreases from 894 Mt in 2024 to 744 Mt in 2050 in the Baseline, aligned with recent EPA estimates indicating a higher historical land sink.  By 2050, the land sink in the Central scenario reaches 1,172 Mt, representing an additional 428 Mt in negative emissions compared to the Baseline.

The lowest emissions reductions across sectors are for non-$CO_2$ gases, which decline to 850 Mt in the Central case — a reduction of only 27% from 2024 levels. Persistent sources like agriculture and waste remain challenging to mitigate, as further reductions would require more systemic changes than those modeled in the current scenarios.

**FIGURE 19.** Greenhouse gas emissions by scenario (Gigatonnes)




## Energy System

Energy system decarbonization in these scenarios relies on four core strategies, or "pillars": (1) enhancing energy efficiency; (2) decarbonizing electricity; (3) electrifying end uses; and (4) capturing carbon for either geological sequestration or the production of carbon-neutral fuels. These strategies are illustrated in the 2050 Sankey diagrams presented in Figure 20 - Figure 24.

The Sankey diagrams track energy flows from primary energy sources on the left to final energy on the right. Key stages, including primary energy, final energy, and various conversion steps, are detailed in figures within the Supplemental Results at the end of this report. Colors are used to indicate downstream flows. And in a few rare cases, energy flowing right to left in the Sankey diagram is indicated. For example, in 2050, electricity to electrolysis to hydrogen flows back to thermal power plants and into electricity. In previous years, these backflows in the Sankey have been pruned, but have been kept this year despite the added complexity.

Consistent with previous Annual Decarbonization Perspectives, the net-zero scenarios assume U.S. energy exports that decline proportionally with global fuel demand, as outlined in the International Energy Agency's World Energy Outlook 2022 under the IEA net-zero scenario.

**FIGURE 20.** Sankey Diagram for 2024 (Exajoules)

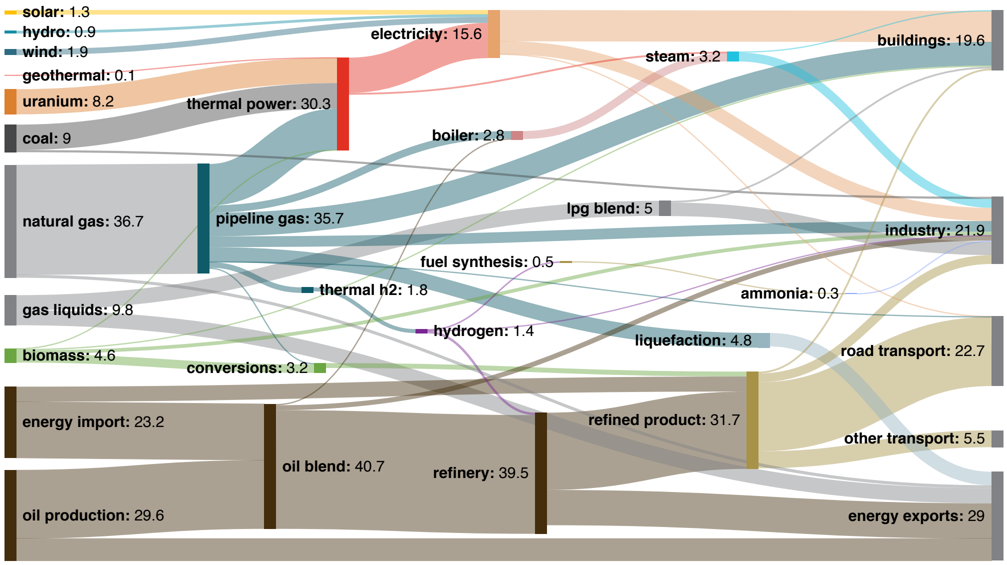



**FIGURE 21.** Sankey Diagram for 2050 Current Policy Scenario (Exajoules)

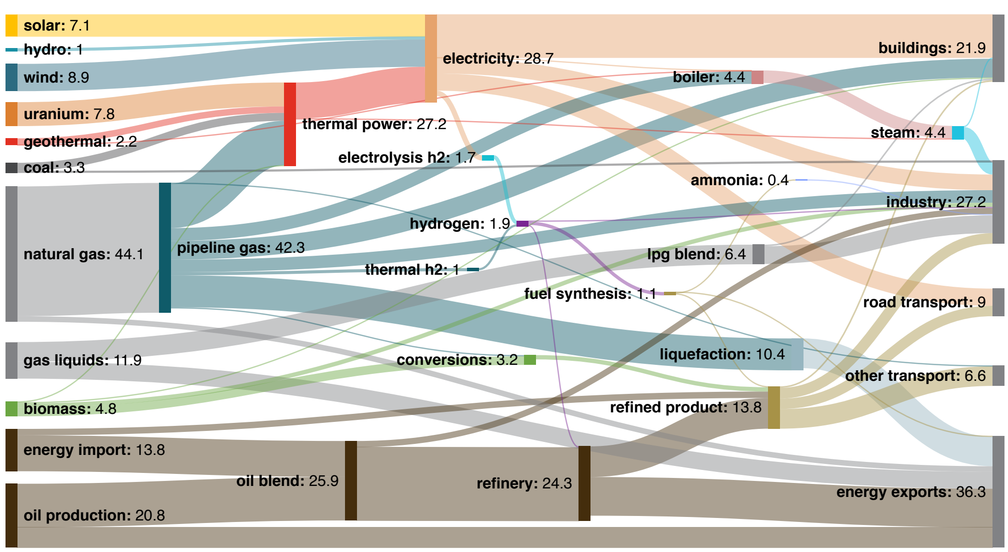


**FIGURE 22.** Sankey Diagram for 2050 Central Scenario (Exajoules)

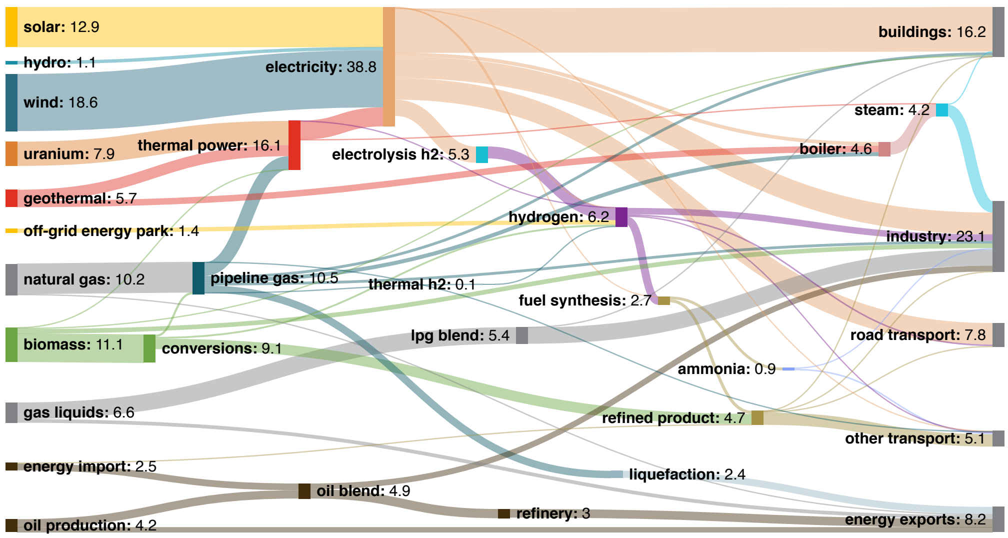



**FIGURE 23.** Sankey Diagram for 2050 100% Renewables Scenario (Exajoules)

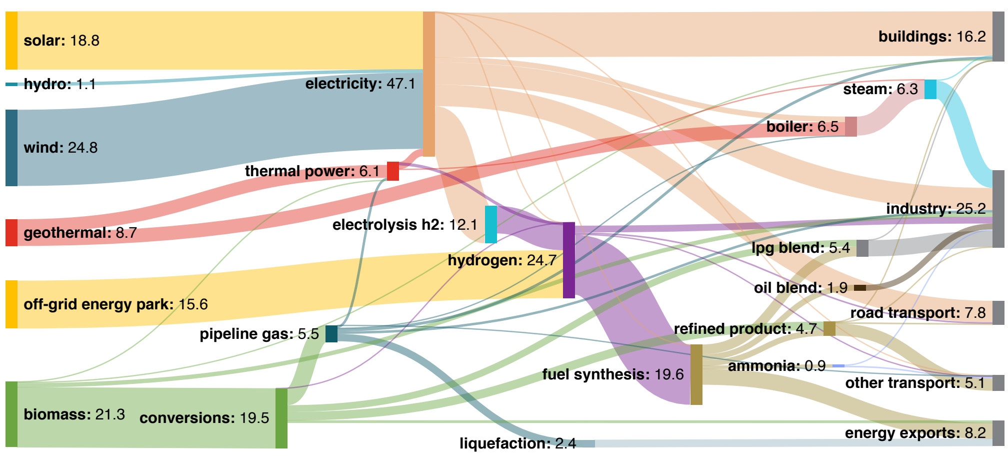
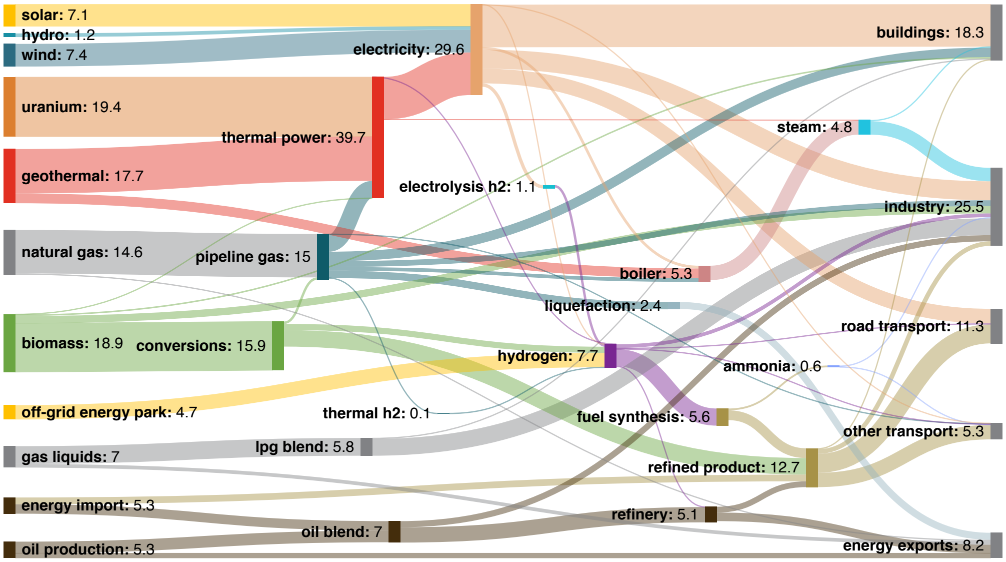


**FIGURE 24.** Sankey Diagram for 2050 Drop-In Scenario (Exajoules)

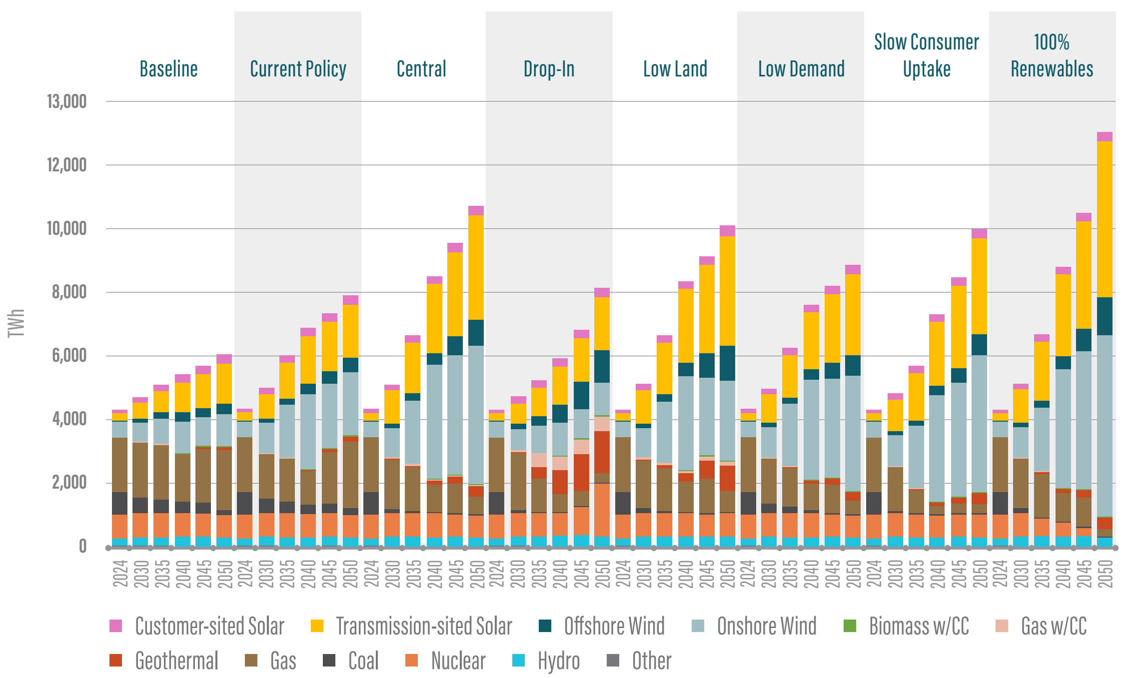



# Electricity Balancing

## Generation and Capacity Mix

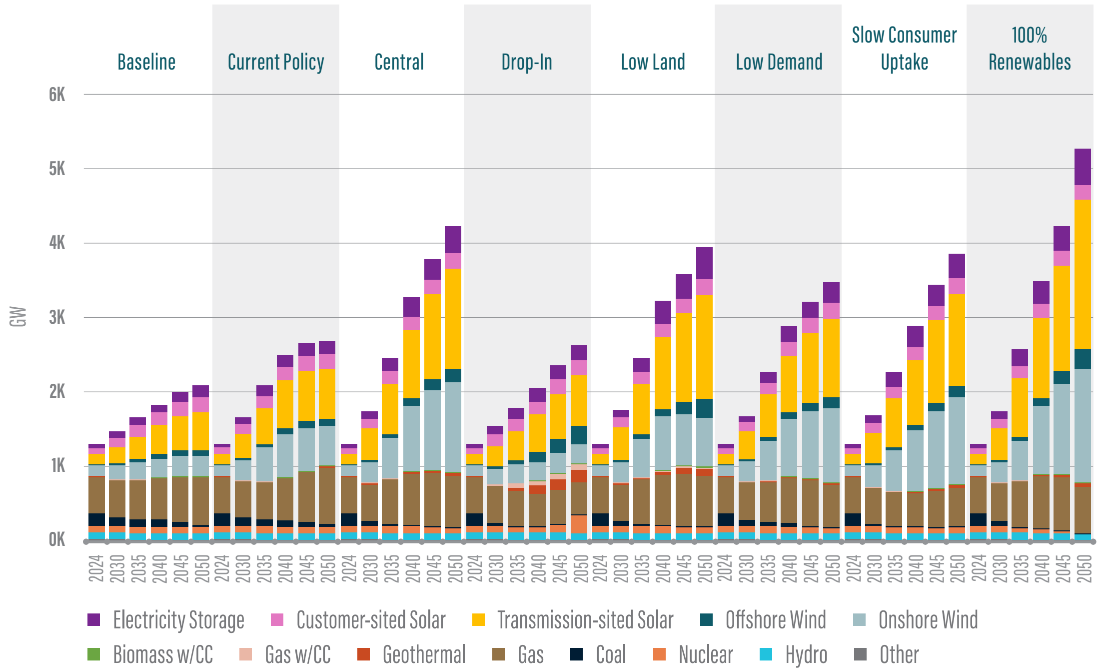
Electricity generation in 2050 net-zero scenarios range between roughly two- and three-times current generation, with the differences driven by electrolysis demand, biomass use, and build-rate constraints (Figure 25). The Central scenario is in the middle of that range (2.5 times today's generation), with wind (48%) and solar (33%) dominating the generation mix. This level of renewable generation is a good economic match with high electrolysis (1500 TWh) and industrial heat (350 TWh) loads that require low-cost energy inputs but can have relatively low utilization rates. Mirroring the rapid rise of renewables, coal generation falls 90% by 2035. In the absence of coal, the >80% share of variable generation is complemented by other forms of dispatchable generation, composed of non-emitting "clean firm" (13%) and natural gas without carbon capture (5%).

**FIGURE 25.** Electricity Generation




The inclusion of next-generation geothermal in *ADP 2024* has a significant impact on the dispatchable capacity mix. Geothermal capacity grows more than 10-fold to 45 GW by 2050 in the Central scenario. Geothermal growth is even more rapid if wind and solar are constrained to current build rates by land use or other limitations, and much greater non-emitting generation is necessary. In the Low Land scenario, clean firm capacity includes 255 GW of nuclear, 176 GW of geothermal, and 89 GW of natural gas with carbon capture. (Note that generation and capacity for non-grid-connected "energy parks" are not shown in the figures.)

**FIGURE 26.** Electricity Generation Capacity




## Modeling the Balancing Problem

The transition to the kinds of electricity systems needed in economy-wide net-zero scenarios will require specialized modeling to examine certain facets of electricity operations and reliability, for example engineering questions related to stability and control of inverter-based resources. However, even though the capacity expansion modeling used in creating the *ADP 2024* scenarios does not address such questions, we contend that sequential hourly electricity modeling over the course of a year, and across all years to mid-century, does illuminate the most critical aspects of electricity balancing from the perspective of cost and policy, even when using large zonal representations and simplified operational constraints.

There are strong first-principles reasons to believe that the greatest share of costs in a high wind and solar electricity system are associated with energy imbalances over long timescales. These imbalances manifest as either prolonged energy deficits or surpluses, the latter leading to renewable curtailment if other uses for the electricity cannot be found. Our work over the last decade has consistently found that costs correlate strongly with the volume of energy that requires balancing, and further that many balancing resources designed to absorb or provide large volumes of energy can also effectively address shorter-duration imbalances.

Other researchers have noted that designing an electricity balancing solution is analogous to assembling a sports team, in which each player excels in a specific role suited to their strengths.[17] Below we highlight the key "players" that collectively ensure reliable and cost-effective electricity service — "winning the game" — in the net-zero scenarios in *ADP 2024*, and that underlie the different generation and capacity mixes shown above. These players are: (1) transmission, (2) sectoral coupling & flexible load, (3) electricity storage, and (4) dispatchable capacity. (Note: We use the terms dispatchable capacity and firm capacity interchangeably to refer to thermal power plants or hydro plants with large reservoirs that are not limited in the duration of their electricity production. The term "clean firm" or dispatchable emission free resources (DEFRs) is a subset of dispatchable capacity.)

## Electricity Balancing at Different Time Scales

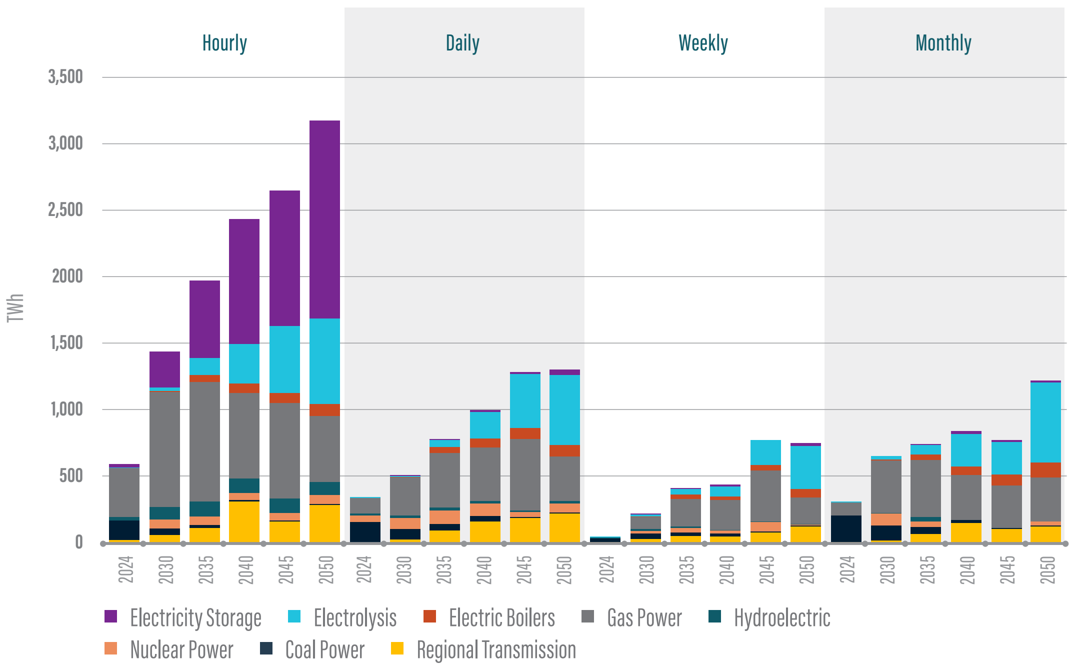
Figure 27 illustrates two crucial aspects of the balancing problem. First, it shows the overall trend of increasing need for balancing over- and under-generation as the share of intermittent wind and solar in generation increases over time during the transition to net zero. Second, it shows this evolution divided into different timescales — hourly, daily, weekly, and monthly — with the contribution made by each resource type at that timescale.[18] "Hourly" refers to the change in load or generation required to meet net load (i.e. gross load minus renewable generation) over a 24-hour period. "Daily" refers to the shifting of energy within a week, "Weekly" to the shifting within a month, and "Monthly" to meeting the residual energy imbalance over the course of a year (this is sometimes called "seasonal" balancing). The dramatic increase in hourly balancing need, which is driven mainly by solar overgeneration in the middle of the day (often illustrated by a "duck curve") is addressed by increasing electricity storage capacity.

But Figure 27 also shows — and this is critical for electricity planners and policymakers to understand — that electricity storage plays only a very minor role in balancing at other time scales. Daily, weekly, and monthly balancing solutions instead employ a combination of different "players" (resources) depending on the time scale and whether the specific balancing problem is over- or under-generation. Overall, it is electrolysis, thermal power plants, and transmission between regions that do most of the heavy lifting. Electrolysis balances during times of renewable overgeneration by turning on to produce a product (hydrogen) that has high value in the net-zero energy system, while thermal power plants are dispatched when renewable generation is inadequate to meet inflexible (must-serve) loads. Transmission shifts energy from one location during periods of overgeneration to another location with under-generation.

17 https://www.nytimes.com/2022/09/20/podcasts/transcript-ezra-klein-interviews-jesse-jenkins.html

18 Balancing contributions are measured by the extent to which a resource helps shift the net load during a specific time frame (e.g., hour, day, week, or month) toward the average net load calculated over a longer balancing period (i.e., from hour to day, from day to week, from week to month, or from month to year).

**FIGURE 27.** Electricity balancing by resource type at hourly, daily, weekly, and monthly time scales in Central scenario through 2050



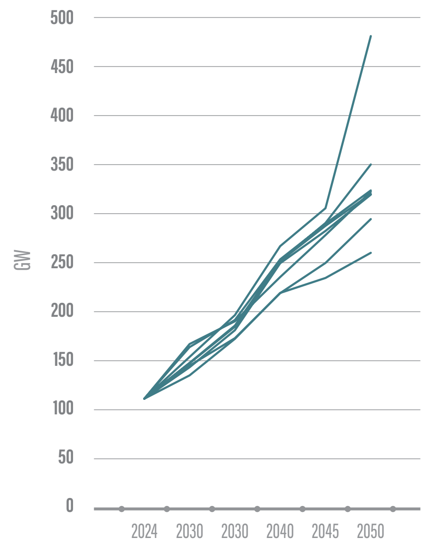

The following sections discuss the most important balancing solutions in greater detail with additional results from the *ADP 2024*.

## Transmission

Transmission infrastructure has long been the backbone of the electricity system, enabling large-scale movement of electricity across regions and providing capacity that reduces local reserve requirements. This role is magnified in a high-renewables system, where it supports the integration of renewables by expanding the geographic reach of intermittent resources. Figure 27 shows that transmission is an important balancing solution across all time scales.

Transmission is needed at two spatial scales: inter-regional (between regions) and intra-regional (within regions). Inter-regional transmission saves cost in net-zero scenarios by allowing the geographic diversity of weather patterns to smooth renewable intermittency, reducing the need for other, more localized balancing solutions that may be more costly. It also allows regions with lower-quality renewable resources to take advantage of high-quality resources in neighboring regions, especially in the case of wind. Inter-regional transmission increases in all scenarios (Figure 28). In the Central scenario, it expands by factor of 3 from today, faster than the growth in electricity generation and much faster than the growth in peak load.

**FIGURE 28.** Inter-regional transmission by year across net-zero scenarios. Scenario with non-economic restrictions on transmission build (Drop-In & Low Land) are excluded




While rapid expansion of *inter-regional* transmission lowers cost in net-zero scenarios, expansion of *intra-regional* transmission is even more essential. Supplying growing electrification loads with new clean generation is the essence of decarbonization, and this absolutely requires intra-regional transmission to connect the two. Without it, achieving net-zero becomes exceedingly difficult.

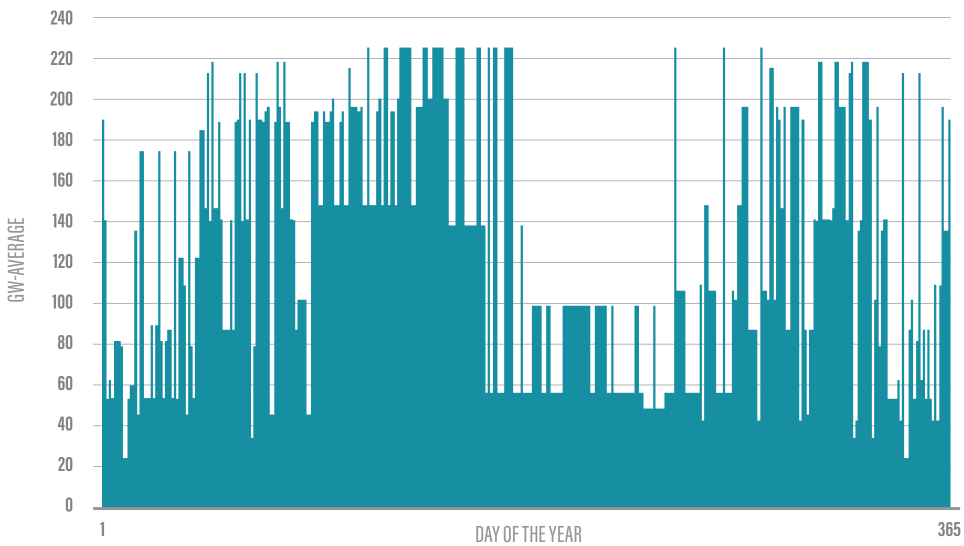
## Sectoral Coupling & Flexible Load

Sector coupling refers to integrating electricity with other sectors in a way that enables various applications (such as industrial heating and hydrogen production) to absorb surplus energy. Sector coupling can store energy much more cost-effectively than dedicated electricity storage, while helping decarbonize other industries in the process. The ideal sectoral coupling application has low capital costs per kW of capacity (e.g., resistive heating, next-generation electrolyzers) and can be overbuilt in order to operate flexibly, ramping up operation only when surplus renewable energy is available. This is illustrated in Figure 29, which shows hydrogen production by electrolysis in the U.S. on each day of the year in the Central case in 2050. Even at the national level, which sums contributions from all regions, the daily variation is apparent. If each region was shown individually, the variation would be even more pronounced.

There are several important synergies between electrolysis and renewable generation. Electrolysis helps reduce curtailment of renewables to about 5%, which is much lower than it would be if sectoral coupling were not deployed.[19] Reducing marginal curtailment, in turn, allows more renewables to be cost effectively built. More renewables being built increases renewable generation on days that would otherwise be short of energy, and this reduces the need for electricity storage and dispatchable capacity. Finally, the hydrogen from electrolysis is used to decarbonize hard-to-abate sectors, and it reduces pressure on land use since e-fuel pathways consume less land per unit of energy than bioenergy pathways.

19 While it is true that renewable curtailment is being reduced by building electrolyzers that themselves only operate at 40-50% capacity factors, and thus get "curtailed" in many hours, this is economically optimal because of the high operating to capital cost ratios of future electrolyzers and the relatively low cost to store bulk hydrogen.

**FIGURE 29.** Daily hydrogen production from electrolysis for the U.S. in Central case in 2050




Another key balancing strategy is flexible end-use loads (e.g. electric boilers, flexible EV charging) that can be turned on and off as system conditions dictate. Flexible loads are especially valuable on the hourly time scale (Figure 27). They help reduce the amount of electricity storage required and also can allow upgrades to the distribution system to be deferred, which is one of the most expensive aspects of electrification.

## Electricity Storage

Electrical energy storage, ranging from diurnal (short-duration) batteries to long-duration storage systems, provides needed flexibility for a high-renewables system. It absorbs excess renewable generation during low demand periods and discharges it during peak periods, bridging shortfalls across time periods and contributing significantly to system reliability. Electricity storage built in all *ADP 2024* scenarios is shown in Figure 30 for both power capacity (GW) and energy capacity (GWh). "Existing storage" is a combination of pumped hydro and currently installed batteries. Li-Ion batteries have high round trip efficiency and are used for daily balancing, particularly in conjunction with solar. With increasing solar penetration over time and longer periods of solar overgeneration, RIO calls for an increase in average Li-ion battery duration from about 4 hours today to 7 hours in 2050 in order to achieve economically optimal outcomes.

The role of long-duration storage is to address energy imbalances on the scale of days rather than hours, typically with lower throughput than diurnal storage. The technologies for long-duration storage are still under development, but in general they aim to achieve much lower $/kWh capital cost than Li-ion even at the expense of lower efficiency.

Accordingly, Figure 30 shows that long-duration storage provides much less power capacity in all scenarios than diurnal Li-ion, but by 2050 it constitutes a significant share of energy storage capacity. However, from the standpoint of overall system balancing, as the balancing time scale moves to weeks and months, and the volume of energy that must be shifted in time is large enough, and the batteries are used infrequently enough (for example, only a small number of charge and discharge cycles in a year), long-duration storage isn't the most cost-effective solution. Instead, dispatchable capacity is deployed to address energy deficits that occur on the longer balancing timescales.

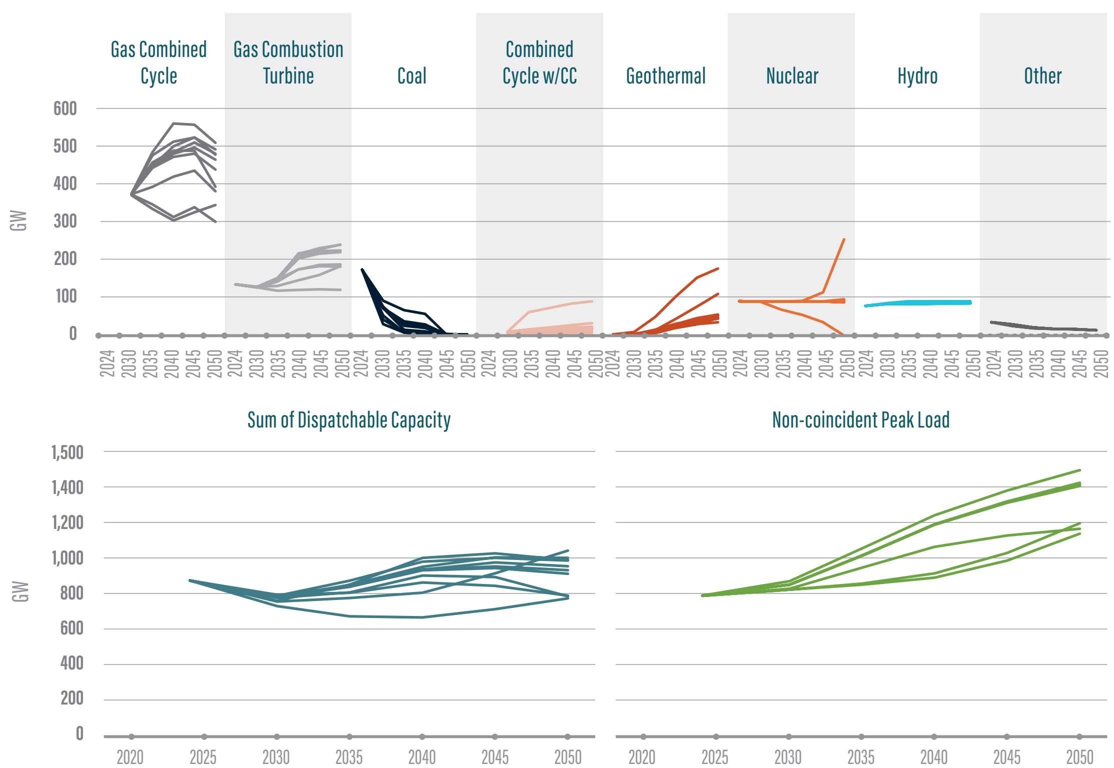
**FIGURE 30.** Electricity storage across scenarios. (Top) Power capacity (GW). (Bottom) Energy storage capacity (GWh)


## Dispatchable Capacity

Dispatchable (or "firm") capacity provides energy during periods of low renewable output and high load (i.e., high *net load*) that cannot be cost-effectively addressed with other balancing solutions. Dispatchable capacity provides balancing by using fuels (or in some cases, water in large reservoirs), which are able to store energy at costs that are orders of magnitude lower than electricity storage. It is important for policy makers to understand two things: (1) that sufficient dispatchable generation — and in the U.S. this mostly means thermal power plants — is critical for the reliability of high renewables electricity systems, and (2) that while these generators may provide a large amount of the system's energy in some hours on some days, if the system is designed correctly, the total amount of energy from these generators over the course of a year is small. Put differently, a high renewables system requires a large thermal capacity, but the capacity factors of these generators are quite low. Some of this capacity can be natural gas without carbon capture if negative emissions elsewhere in the energy system (for example, CCS on biofuel refineries) compensate for the $CO_2$ emissions.

Figure 31 shows dispatchable capacity by type across all scenarios (the multiple lines under each type represent the GW of that type for each scenario). The sum of all the types remains similar to today's dispatchable capacity — about 900 GW +/- 100 GW — throughout the transition to a decarbonized system. The biggest components are gas combined cycle and gas combustion turbines, again with capacities of a similar order to today's in most scenarios.

**FIGURE 31.** (Top) Dispatchable capacity by type across scenarios to 2050. (Bottom Left) Sum of dispatchable capacity across scenarios (Bottom Right) Non-coincident peak load



### *Firm vs. Clean Firm*

"Clean firm" capacity is a subset of dispatchable capacity that has no $CO_2$ emissions, for example geothermal, nuclear, and gas combined cycle with CCS. Clean firm capacity is required to meet net-zero goals in places where low-cost renewable resources don't exist or can't be sited, as occurs in the Low Land and Drop-In scenarios. For U.S. decarbonization developing clean firm resources is an essential insurance policy, and where it displaces renewables, it also helps reduce land impacts. Their development is even more important in other parts of the world than in the U.S., such as in much of Europe and Asia, where there are larger loads and either less land or less plentiful renewable resources.

However, as described above, net-zero goals can be met even if dispatchable capacity is not entirely, or even mostly, clean firm. There is a strong economic argument for this. In electricity planning as in many kinds of industry, high capital costs for generators are justified by high utilization rates, so that the cost is amortized over a large volume of energy produced. Clean firm technologies all come with higher $/kW price tags, so to be cost-effective these need to operate at high-capacity factors and produce a lot of clean energy.

If renewables are not overly constrained in their deployment, dispatchable capacity is, as described earlier, only needed for a relatively small number of hours in a year. In this case, building expensive nuclear or CCS plants and operating them at low-capacity factors is uneconomic compared to using lower capital cost conventional gas generators, and either using non-fossil gas (biogenic, hydrogen, etc.) or using natural gas and compensating with negative emissions elsewhere in the energy system. However, while the basic economics of firm vs clean firm have been apparent in our work for many years, recent difficulties in siting wind at higher rates than has been done historically[20], despite the IRA tax credits, and in building transmission to support renewables of all types, has increased the importance of clean firm resources. In addition, clean firm resources could prove essential where there is a desire to achieve carbon neutrality at a corporate level, independently of the timing of carbon neutrality at the system level.

In addition to likely constraints on renewable deployment and interest from by corporate off-takers, technology progress, as evidenced by the many companies working on nuclear, geothermal, and carbon capture, points to these resources becoming an increasingly important part of the electricity system.

20 https://www.nytimes.com/interactive/2024/06/04/climate/us-wind-energy-solar-power.html

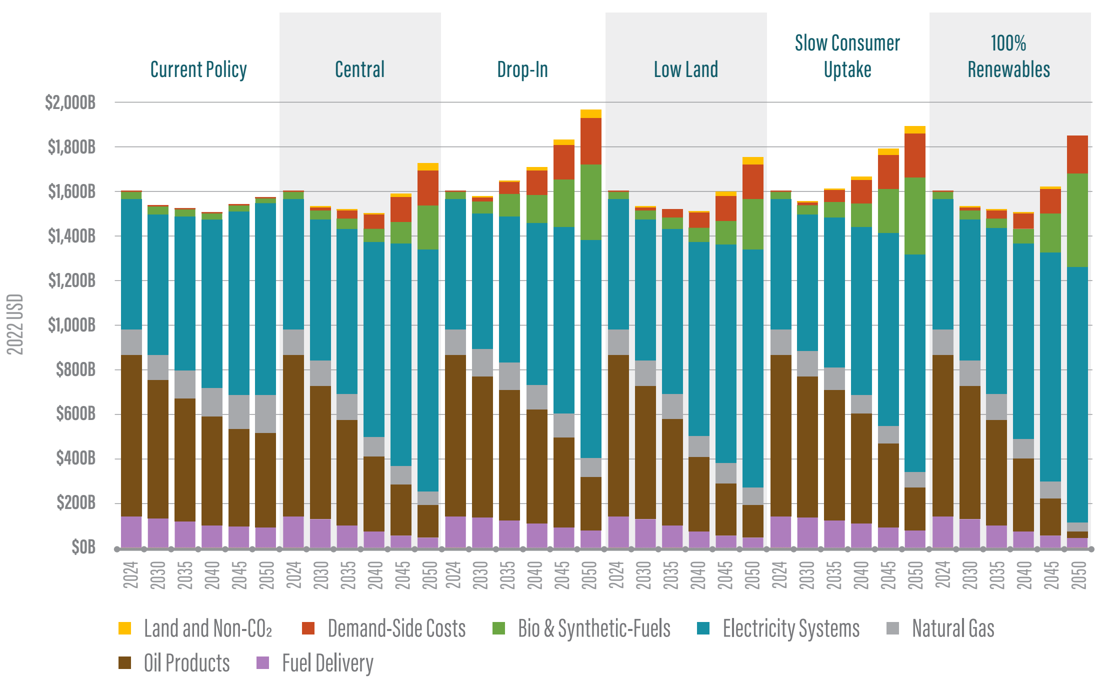
# Cost

## Gross cost

The gross annual cost of the energy system, plus the cost of land sector and non-energy, non-$CO_2$ mitigation measures required to reach economy-wide net-zero, is shown across scenarios in Figure 32. Energy system costs include the annualized cost of capital investments and operating cost for both energy supply (electricity and fuels) and energy end-use technologies (in vehicles, buildings, factories, etc.) Tax credits were subtracted from the gross energy system cost in these calculations since they are experienced as savings by the energy sector.

In the Current Policy scenario, gross costs remain relatively constant out to mid-century, but there is a shift from spending on oil products towards spending on the electricity system as a result of electrification of on-road transportation. With the decrease in projected vehicle costs discussed earlier in the modeling updates section on transportation, the Current Policy scenario has lower system cost than the Baseline scenario (not pictured). For this reason, the net cost of decarbonized scenarios is measured against the Current Policy scenario, rather than the Baseline scenario (which was the case in ADP in previous years).

**FIGURE 32.** Annual Gross Cost of Energy and Other Measures in the Transition to Net-Zero



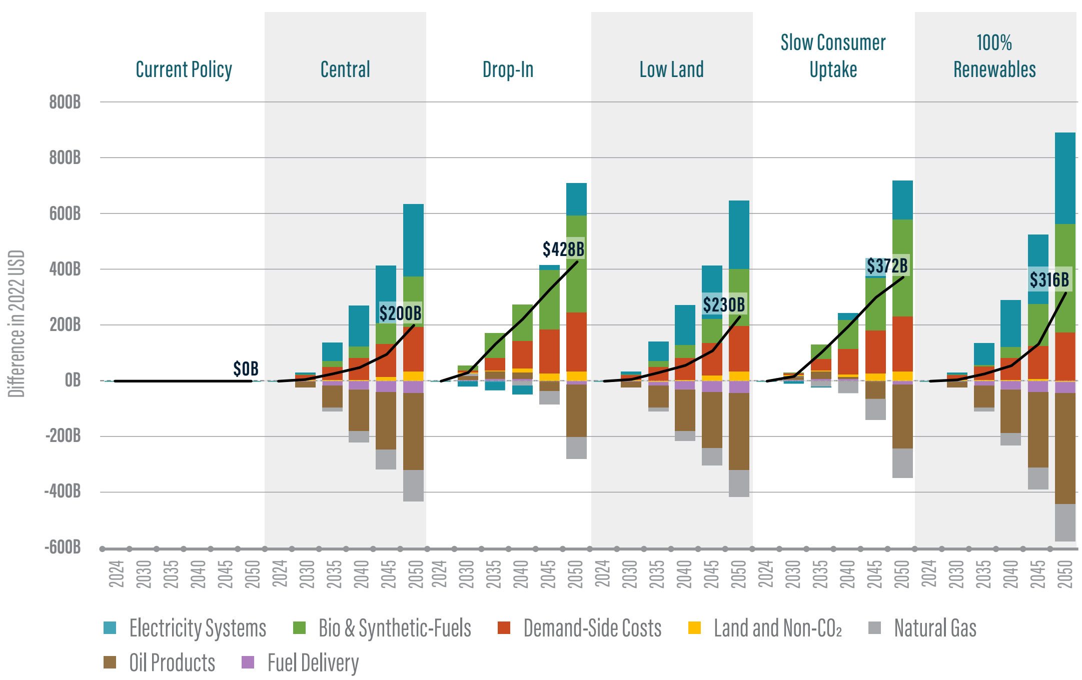
## Net cost

In comparison to the **Current Policy** scenario's gross system cost of $1.58 T/y in 2050, the **Central** scenario increases system cost by $156B/y in 2050 when tax credits are included. If tax credits are removed from the calculation, the net cost becomes $200B/y in 2050 (Figure 33). While tax credits do translate to a reduction in annual spending on energy by U.S. households and businesses, these tax credits must be paid for, and therefore they are a transfer and cannot be treated as a net savings.

The shifts in cost categories seen in the figure reflect a transition in the U.S. energy economy under decarbonization from fuel costs toward infrastructure costs. While oil and gas do incur significant capital costs to enable their extraction, processing, and delivery, the ratio of capital to variable cost is much higher for wind and solar technologies. Except for the variable cost of biomass feedstocks, most other costs of decarbonization, such as electrification and energy efficiency, are capital-intensive. Much of this capital spending is deployed domestically.

The **100% Renewables** scenario has a net cost of $316B/y and the **Drop-In** scenario has a net cost of $428B/y, each representing book-end scenarios (highest and lowest deployment) of renewables for primary energy. And both result in significant increases in societal costs. As seen in past years, slower rates of electrification increase the cost of achieving net-zero by 2050.

**FIGURE 33.** Net Cost of Achieving Net-Zero Greenhouse Gases. Costs are net of the Current Policy scenario and represent the sum of levelized capital costs and variable costs in each modeled year. Tax credits are not included



## Investment

Figure 34 shows capital investment in selected clean energy supply technologies during the period 2022-2050. Total investment in electricity generation is $4.6 trillion (T) in the Central scenario, and ranges from $3.7T to $5.8T across net-zero scenarios, compared to $2.7T in Current Policy. Because of the inclusion of solar PV as an off-grid electricity supplier for energy parks in this year's analysis, and the higher potential levels of solar deployment this implies, a significant share of what was categorized under "solar" in *ADP 2023* has been shifted to "Energy Parks" in *ADP 2024*, as seen in the figure. This change does not represent a reduction in overall spending on solar PV, but a recategorization that more accurately represents what is driving PV investments.

As was the case in *ADP 2023*, investment is dominated by wind and solar in all scenarios except the Drop-In scenario. Unlike *ADP 2023*, however, the largest investments in the Drop-In scenario are for geothermal, rather than nuclear power, though nuclear investment remains significant. It is important to recognize that the modeled investment levels in Figure 34 are based on nth-of-a-kind technology cost forecasts, for example those from the NREL *Annual Technology Baseline*. Timely and proactive investment in R&D and early commercialization is required to attain the market size and price points implied by these levels of investment.

**FIGURE 34.** Capital investment (2022-2050) by Scenario and Technology


## Renewable Siting Maps

Deployment of wind and solar is a key part of net-zero pathways because they are the most plentiful and lowest-cost primary energy that is also emissions free. However, their diffuse nature presents a unique challenge as large land areas are required to replace the energy we currently derive from fossil fuels. The diffuseness and/or remoteness of wind and solar also makes new transmission to access these resources critical, another piece of infrastructure that is difficult and time consuming to site, yet essential for decarbonization pathways.

One tool for understanding the land use implications of wind and solar power is through the use of maps that help visualize the different portfolios selected in the RIO model in different net-zero scenarios. These visualizations are meant to faithfully represent the land footprint of wind and solar farms, although the on-the-ground impacts are not necessarily as great as the maps suggest. Wind, in particular, can be co-located with agricultural or recreational uses, and while the contours of a windfarm, including setbacks, can be quite large, its direct land use is small. Solar farms, on the other hand, occupy far less land per megawatt, but this area is more completely covered with racks and panels. The social and environmental impacts of renewable sitting have been explored by EER in great depth in partnership with The Nature Conservancy as part of the Power of Place projects which are described in more detail elsewhere[21].

The process of creating these maps is often called "downscaling" and starts from a set of candidate projects that involve geospatial analysis of resource potential and transmission cost. For *ADP 2024* we have used a set of candidate wind and solar projects from NREL (release year 2023) that were created using the reV model.[22] We adopted the NREL Limited Access supply curve for wind and solar for all *ADP 2024* scenarios to better reflect recent trends in renewable sitting availability. Candidate projects are chosen from the portfolio of resources selected in the RIO optimization based on a score that indicates the likelihood that they can be sited. This score is produced by a machine learning algorithm called a random forest classifier that is trained on existing wind and solar projects in the U.S. Details of the downscaling methodology are provided in the technical appendix of *ADP 2024*.

When interpreting the downscaled maps shown below, it is important to recognize that they are illustrative. The resources could have been arranged in many different geographic patterns with nearly identical attributes and costs. Our modeling necessarily lacks much of the information, both quantitative and qualitative, that would be needed to guide the development of these resources in the real world. These maps, therefore, are a tool for visualizing possible net-zero pathways, but they are not forecasts and make no claim of being optimally sited.

Figure 35 shows existing (2024) wind and solar while Figure 36 - Figure 40 show wind and solar in 2050 across different scenarios. Solar, onshore wind, and offshore wind (yellow, blue, pink) are grid connected, while solar and wind energy parks (red and green) are connected via pipelines (hydrogen, ammonia, or synthetic fuels) and are assumed not to have an electrical connection with the rest of the grid. Energy parks generally appear in places with excellent resource quality, but that are further from population centers and would therefore be costly to connect with transmission. Across the scenarios, the impacts of land-use restrictions, renewable siting rates, and availability of fossil fuels result in significant changes in both total land use and the way it is distributed.

21 https://www.nature.org/en-us/what-we-do/our-priorities/tackle-climate-change/climate-change-stories/power-of-place/
22 https://www.nrel.gov/gis/renewable-energy-potential.html

**FIGURE 35.** Wind and solar siting today (2024)

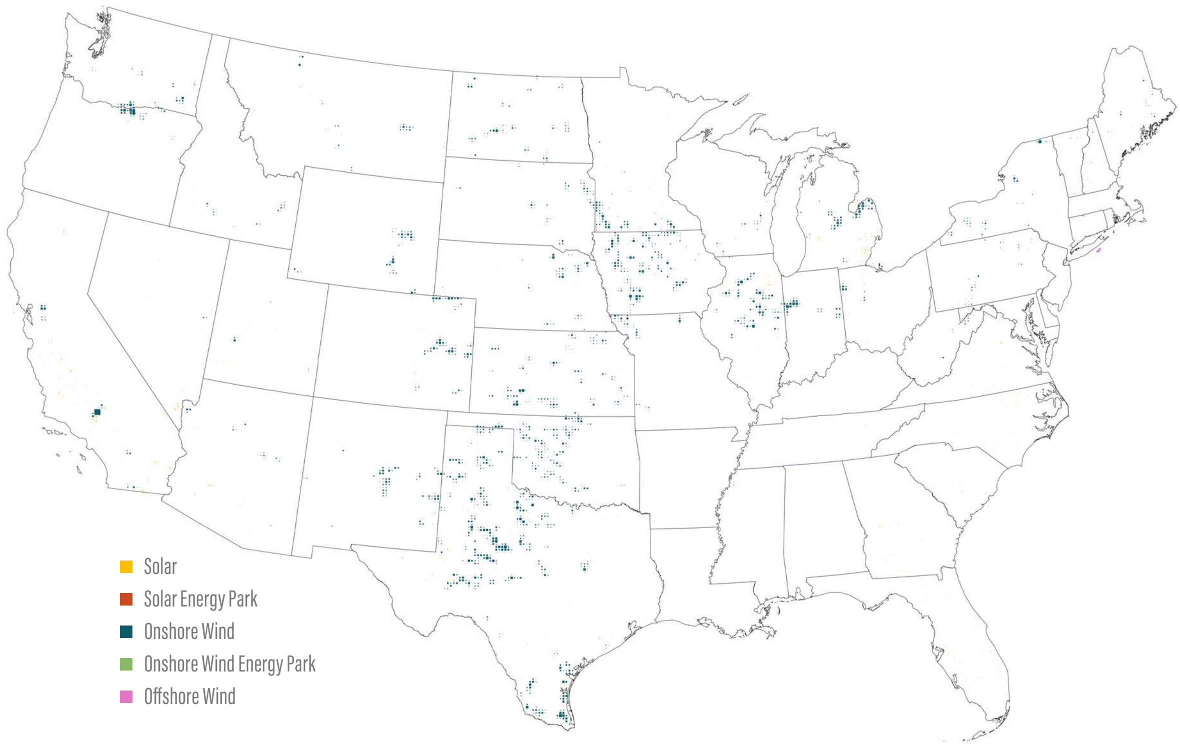



**FIGURE 36.** Downscaled wind and solar in 2050 for the Current Policy scenario

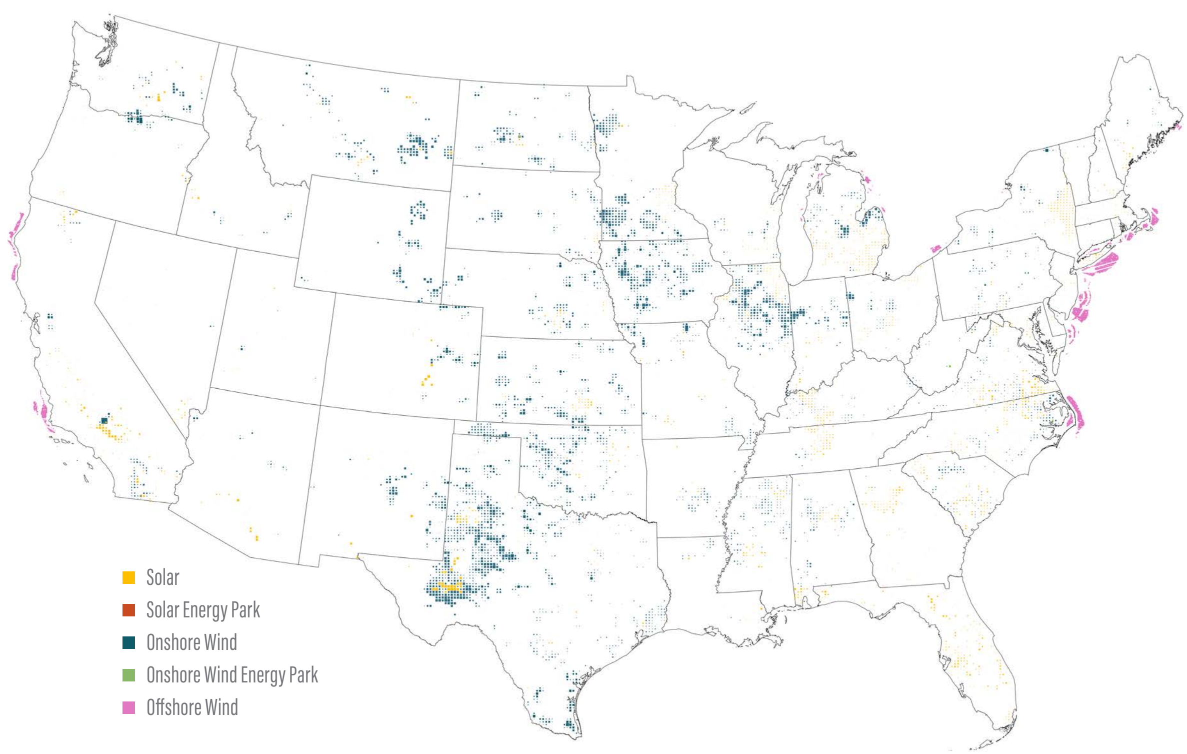


**FIGURE 37.** Downscaled wind and solar in 2050 for the Central scenario

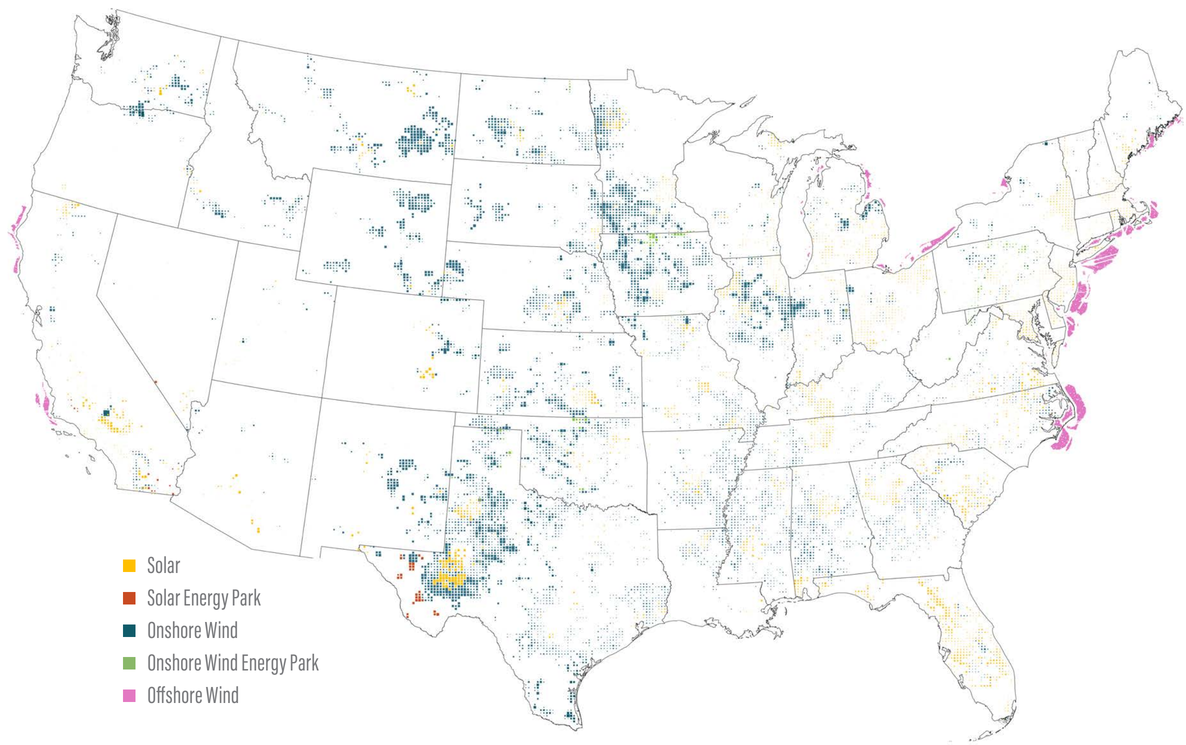



**FIGURE 38.** Downscaled wind and solar in 2050 for the Low Land scenario

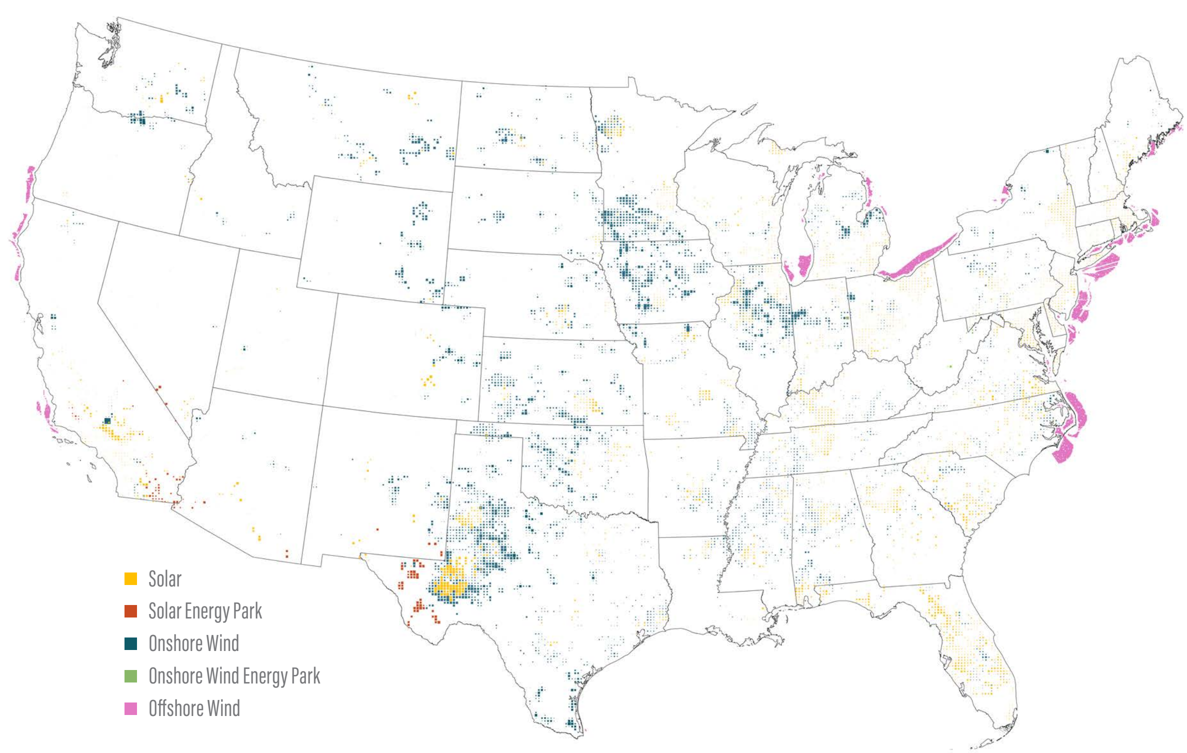


**FIGURE 39.** Downscaled wind and solar in 2050 for the Drop-In scenario

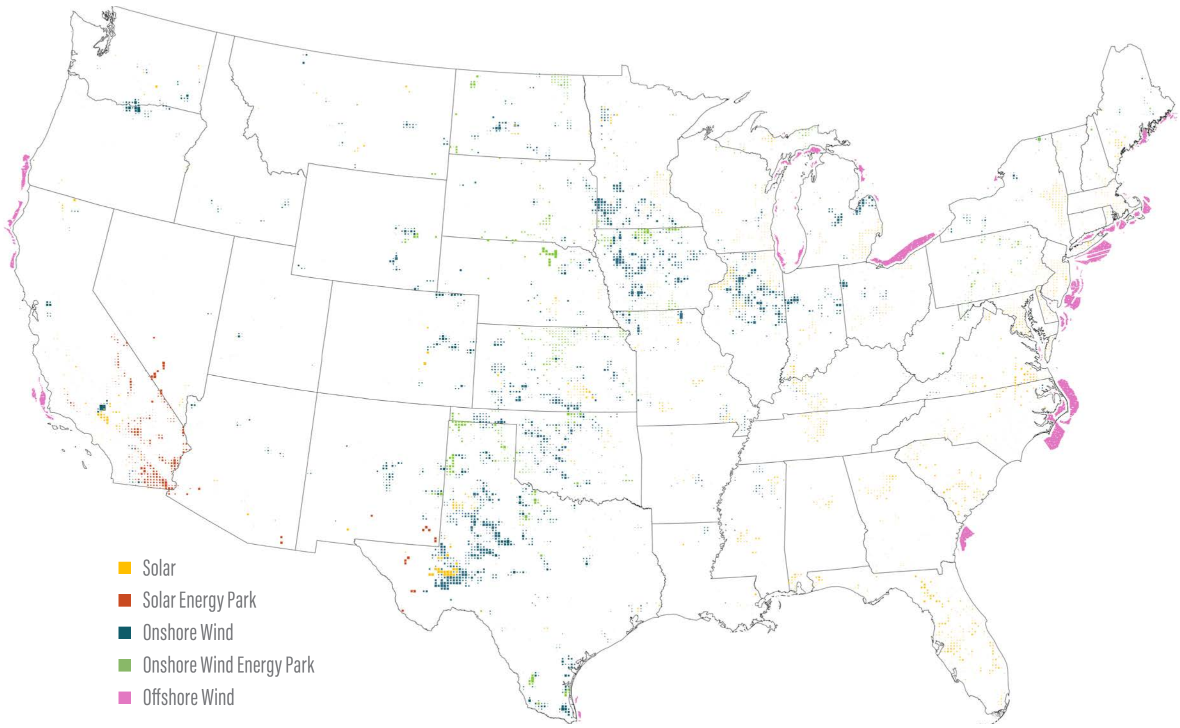
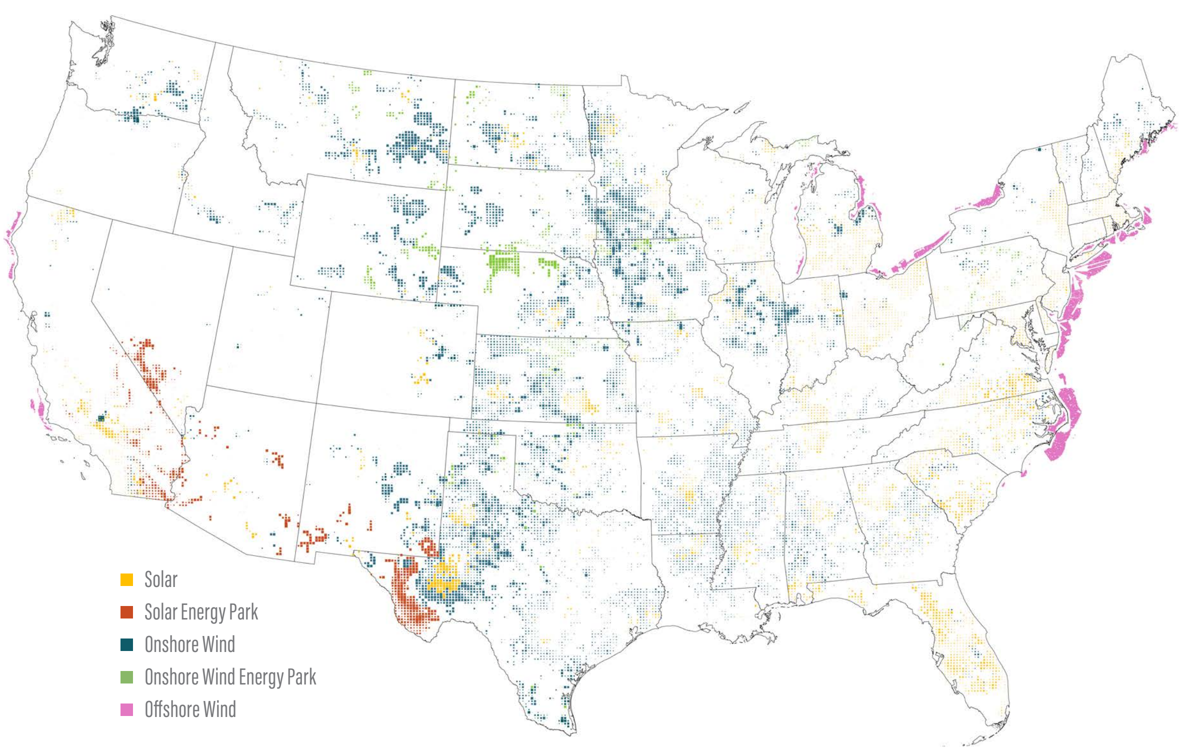



**FIGURE 40.** Downscaled wind and solar in 2050 for the 100% Renewables scenario



# V TECHNOLOGY EXPLORATION

## Green Premiums for Key Technologies

The concept of Green Premiums was the central theme of Bill Gates' 2021 book, How to Avoid a Climate Disaster.[23] Simply put, it is the difference in cost between a product that emits $CO_2$ and an alternative that doesn't. This concept is useful because it shows where efforts to achieve technological breakthroughs need to be focused. Where the breakthrough is sufficient, the Green Premium is reduced to zero or made negative, meaning that the decarbonized technology is able to successfully compete economically with the carbon-emitting incumbent. In the cases where the Green Premium is not reduced to zero, it is a measure of the political will — in the form of subsidies and/or mandates — that is required for the technology to be deployed at the scale needed to reach ambitious climate targets.

The good news for people concerned about mitigating climate change is that technological progress in many key areas has been a bright spot over the past decade, and that Green Premiums have dropped precipitously as a result. The team at Evolved Energy Research conducted their first decarbonization pathways study for the U.S. as part of the Deep Decarbonization Pathways Project, published in 2014.[24] At that time, solar PV cost 3x what it does in the ADP 2024, and batteries were so expensive that their use in electrifying medium- and heavy-duty trucks wasn't included in the 2014 analysis. Obviously, much has changed on the technology front in a single decade.

23 B. Gates (2021). How to avoid a climate disaster: the solutions we have and the breakthroughs we need.
24 Williams, J.H., B. Haley, F. Kahrl, J. Moore, A.D. Jones, M.S. Torn, H. McJeon (2014). Pathways to deep decarbonization in the United States.

While remarkable technology progress has occurred in some areas — in large part thanks to policies that have created markets where increasing scale and learning-by-doing can bring down costs — there is still a considerable way to go in other areas. In ADP 2024 our exploration of technology challenges focuses on two areas: (1) Green Premiums for decarbonized fuels, and (2) cost reductions needed for deployment at scale of emerging technologies in electricity and carbon removal.

## Decarbonized Fuels

It is widely accepted — and a durable result of our own modeling over the past decade — that the transition to net-zero requires decarbonized fuels for applications in which electrification is not a viable solution (e.g., aviation, chemical feedstocks). Below we compare this year's cost assumptions for decarbonized fuels to those for conventional fossil fuels in three important applications: steam, hydrogen, and jet fuel. This comparison employs two key simplifying assumptions. (1) While our high-resolution optimization modeling in RIO shows that decarbonized fuels have very different cost profiles in different regions of the country as key variables change (for example, the cost of hydrogen from electrolysis is dependent on wind and/or solar resource quality, etc.), for this comparison we use the costs from favorable locations where the emerging technologies are most likely to be deployed and most competitive with incumbent technologies.[25] (2) **We have calculated technology costs excluding tax credits from the Inflation Reduction Act (IRA) and similar incentives**, the better to focus on the underlying technology costs.

25 For example, e-fuels are likely to be produced in the wind-belt in places like west Texas before anywhere else.

Figure 41 compares the cost of steam supply for a conventional gas boiler to that from three decarbonized sources: next-generation geothermal, thermal energy storage (TES), and heat pumps. For all the alternatives, producing decarbonized steam remains at a premium out to mid-century. The most-promising of the alternatives is next-generation geothermal, which begins to approach the cost of steam from gas boilers, assuming declining costs of drilling, well stimulation, and other breakthroughs analogous to those pioneered in the oil and gas sector. Note that this result only holds for large-scale facilities (requiring 5+ geothermal wells). Steam from TES in the Wind Belt remains about $5/MMBtu higher than conventional steam by 2050, which follows from the fact the capital costs for TES are higher than for gas boilers and the input energy for TES–decarbonized electricity–costs more than natural gas. Heat pump steam is the least competitive with gas boilers, as the capital cost is even higher, and it cannot operate with the same flexibility. (Not shown here, heat pumps do outcompete TES in parts of the country where electricity cost is higher or T&D upgrade costs are high).

**FIGURE 41.** Levelized cost of steam by technology, ignoring tax credits

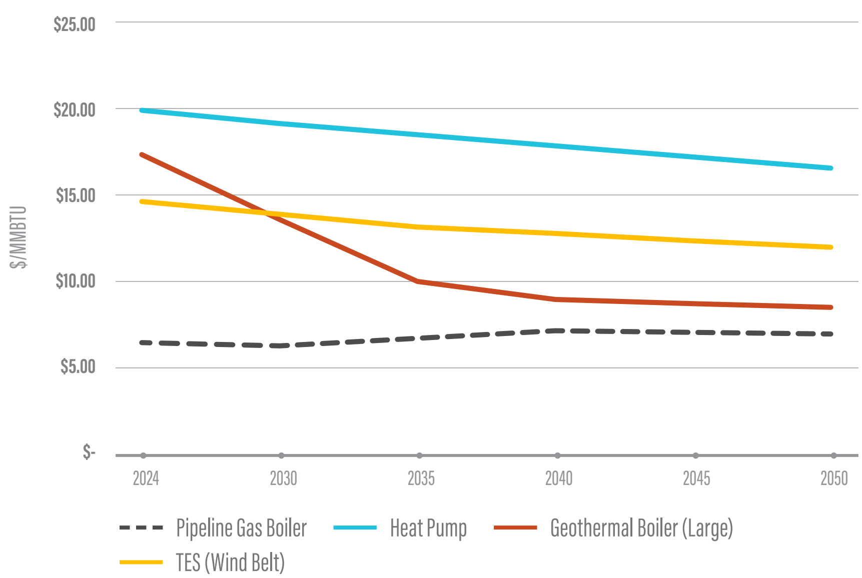


Figure 42 compares the cost of hydrogen from conventional steam methane reforming (SMR) to that from three decarbonized sources: bioenergy with carbon capture and storage (BECCS H2), electrolysis, and geologic hydrogen (Geo H2). Overall, decarbonized hydrogen starts with a significant green premium, but this shrinks considerably over time. For BECCS H2, the reduction in cost over time is driven primarily by the negative emissions it produces, which steadily increase in value in the transition to net zero. The reduction in hydrogen cost from electrolysis is a function of both declining capital cost for electrolyzers and also declining cost for the wind and solar power that provide the energy input to the process. Geo H2, if it is indeed available at $1/kg as assumed in our sensitivity analysis, would be competitive against conventional SMR with no transport cost. If transport cost is included, Geo H2 would remain at a premium in most locations.

**FIGURE 42.** Levelized cost of hydrogen, ignoring tax credits and transportation cost

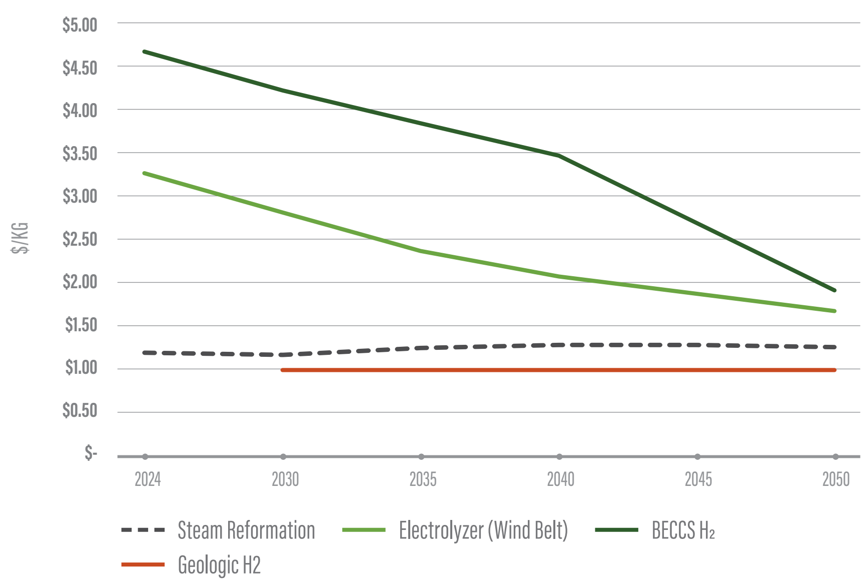
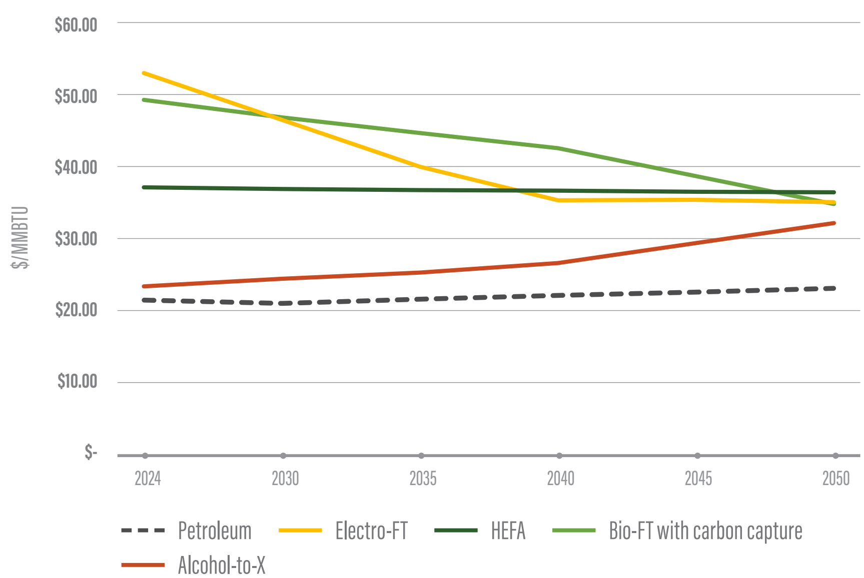



Figure 43 compares the cost of jet fuel from petroleum to that of sustainable aviation fuel (SAF) from four decarbonized sources: electrolysis with Fischer-Tropsch (Electro FT), biomass with Fischer-Tropsch (Bio FT), HEFA, and ethanol-to-jet fuel ("alcohol-to-x"). In general, SAF technologies have a large green premium, which narrows over time but by 2050 is still significant. Ethanol-to-jet fuel and HEFA are the primary focus in the SAF industry today due to their lower current cost. However, feedstock costs can vary significantly, which implies large error bars surrounding the values shown in the figure. The increase in ethanol-to-jet fuel cost over time is a result of the marginal emissions price applied to $N_2O$ emissions from fertilizer used to grow corn. Bio FT has a declining cost trajectory, as in the case of hydrogen, as a function of the increasing value of negative emissions. Electro FT cost is dominated by the cost of producing hydrogen from electrolysis, especially in the near-term. In the long term, the cost of supplying carbon neutral $CO_2$ for use in the synthesis process is also an important factor in E-fuel cost ($CO_2$ constituting1/3 of the input cost and H2 the other 2/3).

**FIGURE 43.** Levelized cost of jet fuel, ignoring tax credits




## Technology Deployment Cost Sensitivity

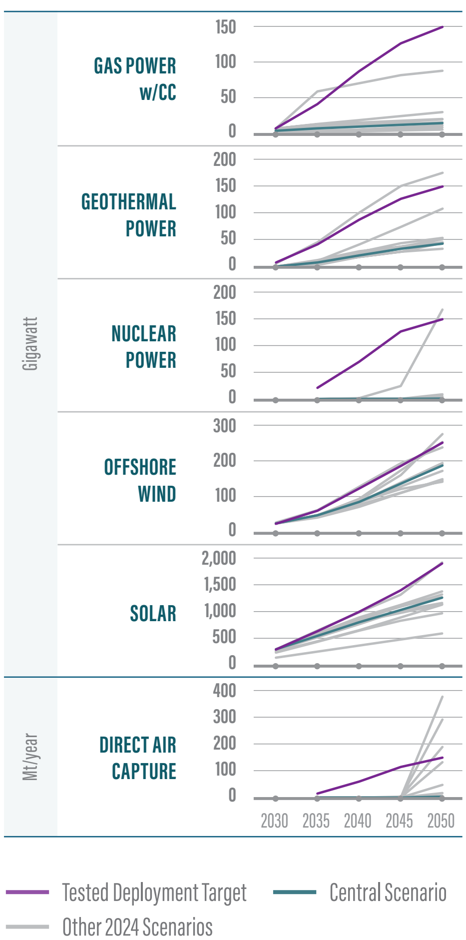
An alternative application of the Green Premium concept is to determine what cost a low-carbon technology must reach in order to achieve mass deployment in different policy scenarios. For this analysis we look at six low-carbon technologies, five in electricity — advanced nuclear, next-generation geothermal, natural gas with CCS, utility-scale solar, and offshore wind — plus sorbent-based direct air capture. Figure 44 shows the range of capacity for each technology across all *ADP 2024* scenarios. The upper end of the range for each is a proxy for the capacity of that technology that would be needed to achieve net-zero targets if other decarbonization strategies fail to materialize.

For this sensitivity analysis, a deployment trajectory for each technology was developed based on its highest deployment across scenarios, with a ramp-up consistent with realistic annual build rates. (An example of the latter point is direct air capture, which is not deployed until 2045 in the *ADP 2024* scenarios. In this analysis, it is ramped up more gradually, starting in 2035.) As seen in Figure 44, the target values in 2050 are 150 GW for nuclear, geothermal, and gas CCS; 250 GW for offshore wind; 1900 GW for transmission-site solar; and 150 million tonnes of $CO_2$ per year for DAC.

We then put the deployment target into the RIO model as a required minimum capacity build. The shadow price of this constraint in the RIO optimization is the cost reduction this technology would need to achieve, relative to the input cost, in order to reach the target deployment level. This 'required cost' target represents the point at which the overall scenario cost is the same with or without the technology. And the more technologies that reach these cost targets, the more robust a scenario is against the failure of other decarbonization strategies.

The 'required cost' determined in this way is specific to a given scenario. The analysis was conducted for two scenarios: Central and Current Policy. The required cost of the technology to achieve the target deployment is higher in the Central scenario (which has a net zero constraint) because the effective cost of carbon is higher than in Current Policy (which does not have a net zero constraint). The difference between the two is the impact of the carbon constraint on technology competitiveness. Put differently, the reduction in cost needed to make the technology competitive is greater under Current Policy, where it must compete with existing conventional technologies that have no constraint on their carbon emissions.

**FIGURE 44.** Deployment of electric generating capacity in the Central scenario (blue) and other scenarios (grey) in ADP 2024, plus target deployment level in the sensitivity analysis (purple).



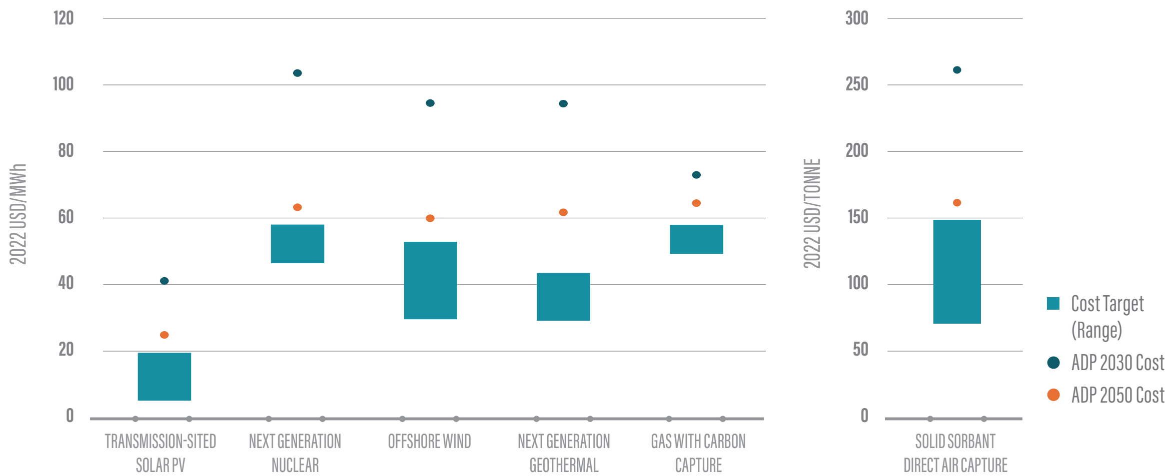

The required cost level for each technology was evaluated independently. For example, carbon capture and nuclear are each deployed without the other, as the required cost would be lower if both were deployed at the same time. All but one of the technologies exist on supply curves within our model that have multiple bins expressing different costs, performance, and maximum capacity levels in different locations. All the technologies except nuclear — next-generation geothermal, natural gas with CCS, utility-scale solar, offshore wind, and DAC — have costs that vary by location. Some subtleties in the sensitivity results are explained by the underlying assumptions that have gone into *ADP 2024* supply-curves. For example, geothermal turns out to have a lower required cost than nuclear because geothermal potential for electricity generation is primarily located in the western U.S. where only one-sixth of U.S. electricity load is. Nuclear, on the other hand, can be built anywhere across the country (that it is legal to do so), including on the east coast where far

greater electricity demand exists. As a result, nuclear “required cost” does not need to be as low as that for geothermal in order to reach the same 150 GW deployment target.

The results of the analysis are shown in Figure 45 for five decarbonized electric generation technologies plus sorbent-based DAC. For transmission-sited solar to reach the target level of 1900 GW, the required 2050 cost is $20/MWh in the Central scenario and $5/MWh in the Current Policy scenario, compared to the 2050 value of $25/MWh in *ADP 2024*. In other words, a cost reduction of $5/MWh put 1,900 GW within reach in the net-zero case, but a reduction of $20/MWh is required under current policy.

For nuclear, the required cost range to reach 150 GW is 47-58 $/MWh, versus the 2050 value in *ADP 2024* value of 63 $/MWh. For gas CCS, the required cost range to reach 150 GW is 49-58 $/MWh, versus the 2050 value in ADP 2024 value of 65 $/MWh. For geothermal, the required cost range to reach 150 GW is 29-44 $/MWh, versus the 2050 value in *ADP 2024* value of 62 $/MWh. For offshore wind, the required cost range to reach 250 GW is 30-53 $/MWh, versus the 2050 value in *ADP 2024* value of 60 $/MWh. The required cost to reach the target deployment of 150 million metric tons per year of DAC capacity is 150 $/tonne in the Central scenario and 71 $/tonne in the Current Policy scenario, versus 163 $/tonne in 2050 in ADP 2024.

**FIGURE 45.** Required levelized cost range for decarbonized generating technologies for reaching deployment targets in Central and Current Policy scenarios (represented by the top and bottom of the blue bar) plus values for 2030 (blue dot) and 2050 (orange dot) used in ADP 2024 scenarios.




We believe these type of cost targets to be essential for guiding R&D, informing investors, and helping technology companies align their strategies with decarbonization goals. For researchers and developers, clear cost targets provide a focused benchmark, directing innovation efforts toward reducing production and deployment costs to competitive levels.

VI

# COMPARISONS WITH PRIOR YEARS

## Emissions

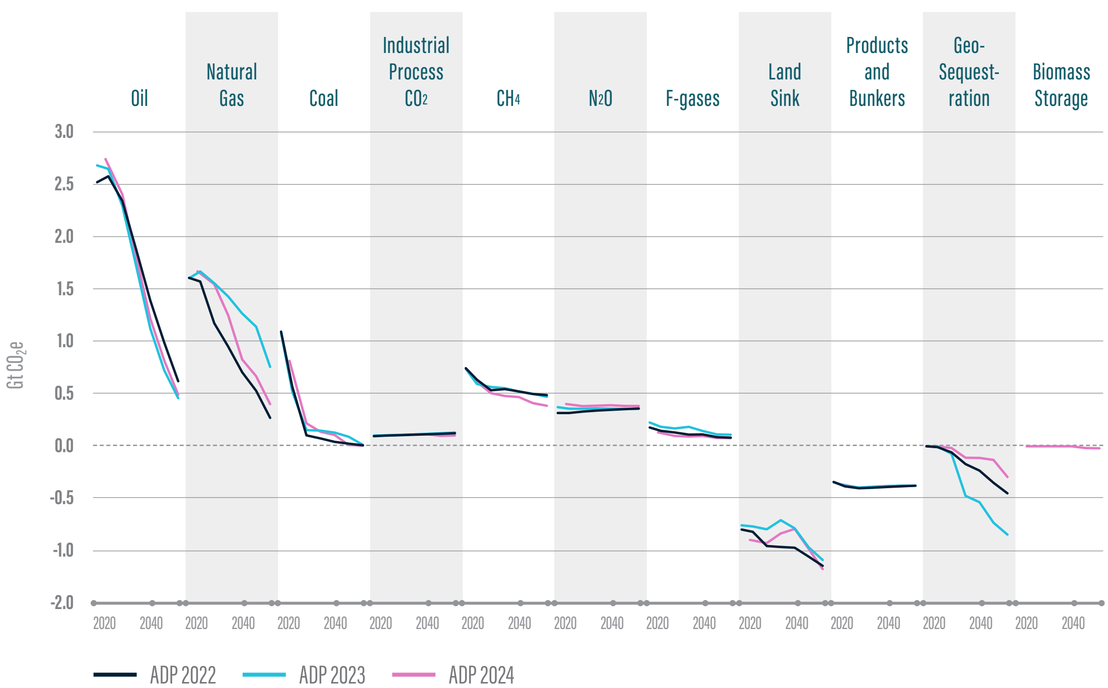
Figure 46 compares U.S. greenhouse gas emissions in the Central scenario in *ADP 2024* with results for the previous two *ADPs*. $CO_2$ gross emissions are shown by fossil fuel source and negative $CO_2$ emissions are shown by type of sink (e.g., land sink, geologic sequestration, etc.), along with methane, nitrous oxide, and F-gas emissions.

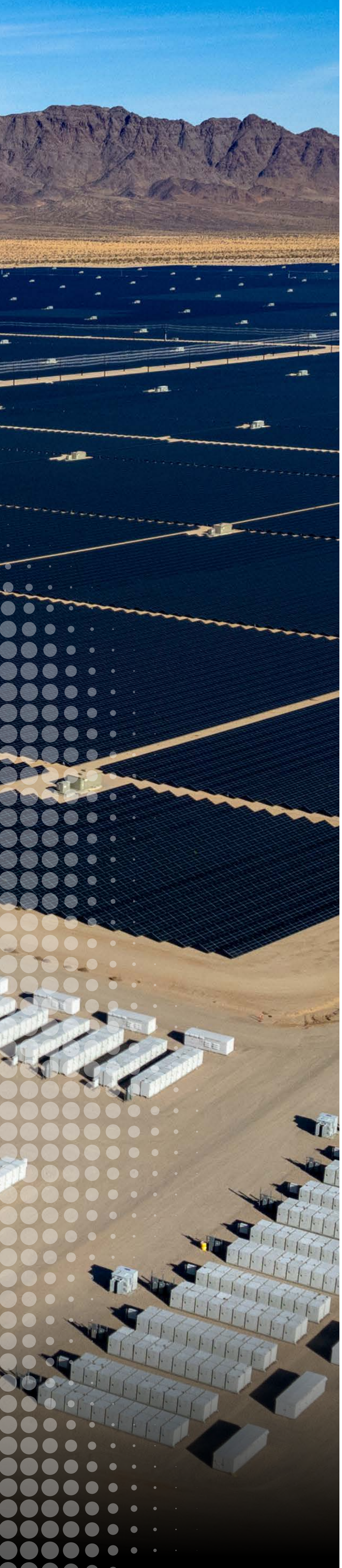
As the figure shows, the largest differences between the *ADP 2024* results and *ADP 2023* are in gross $CO_2$ emissions from natural gas combustion and in geologic carbon sequestration. In net-zero scenarios, coal and oil are displaced by clean energy more rapidly and completely than natural gas, largely as a result of electricity decarbonization and transportation electrification. As the last fossil fuel displaced, natural gas competes on the margin with clean technologies and fuels, and the balance of this competition is sensitive to changes in relative economics including the cost of offsetting with negative emissions.

*ADP 2023* had higher gross natural gas emissions as a result of higher adoption of gas with carbon capture in electricity generation. In *ADP 2024*, this gas CCS capacity decreased substantially for three reasons: (1) the assumption that IRA tax credits for wind and solar are extended through 2040, making it less urgent to build gas CCS by 2035 to take advantage of those tax credits; (2) reductions in non-$CO_2$ emissions in the baseline, together with an increase in the baseline land sink, due to adjustments in EPA data. Both of these translate to a lower requirement for reducing energy system emissions in the 2030s; (3) the emergence of geothermal as a lower cost "clean firm" option that outcompetes gas CCS in some places where it appeared in previous *ADPs*, such as California.

Geologic sequestration in *ADP 2024* is at its lowest level so far in the Central scenarios, less than half of last year's value. Factors driving this in addition to the change in gas CCS include higher electrification levels in 2050, lower non-$CO_2$ emissions (and thus lower requirements for negative $CO_2$ emissions to compensate), a higher $CO_2$ land sink, reduction in process $CO_2$ emissions from the use of LC3 in cement, and lower cost hydrogen coming from solar energy parks. The lower the cost of hydrogen, the greater the utilization of $CO_2$ for synthetic hydrocarbons, and the lower the $CO_2$ sequestration. This effect is amplified in the geologic hydrogen (Geo H2) sensitivity. Direct biomass storage (carbon vaulting) has been introduced in *ADP 2024* for the first time but plays a small role in the Central scenario.

**FIGURE 46.** Comparison of gross U.S. greenhouse gas emissions (Gt $CO_2e$) by type in Central scenario to 2050, including $CO_2$ by fossil fuel source and negative $CO_2$ emissions by sink, in ADP 2022, ADP 2023, and ADP 2024.





## Electricity Capacity

Figure 47 shows electricity generating capacity by type across scenarios for the three years of ADP results. Since the treatment of energy parks in our analysis has changed each year — *ADP 2022* had no energy parks, *ADP 2023* had wind-only energy parks, and *ADP 2024* has wind and solar energy parks — for better comparability, energy park solar and wind capacity was added to *ADP 2024* on-grid solar and onshore wind capacity.

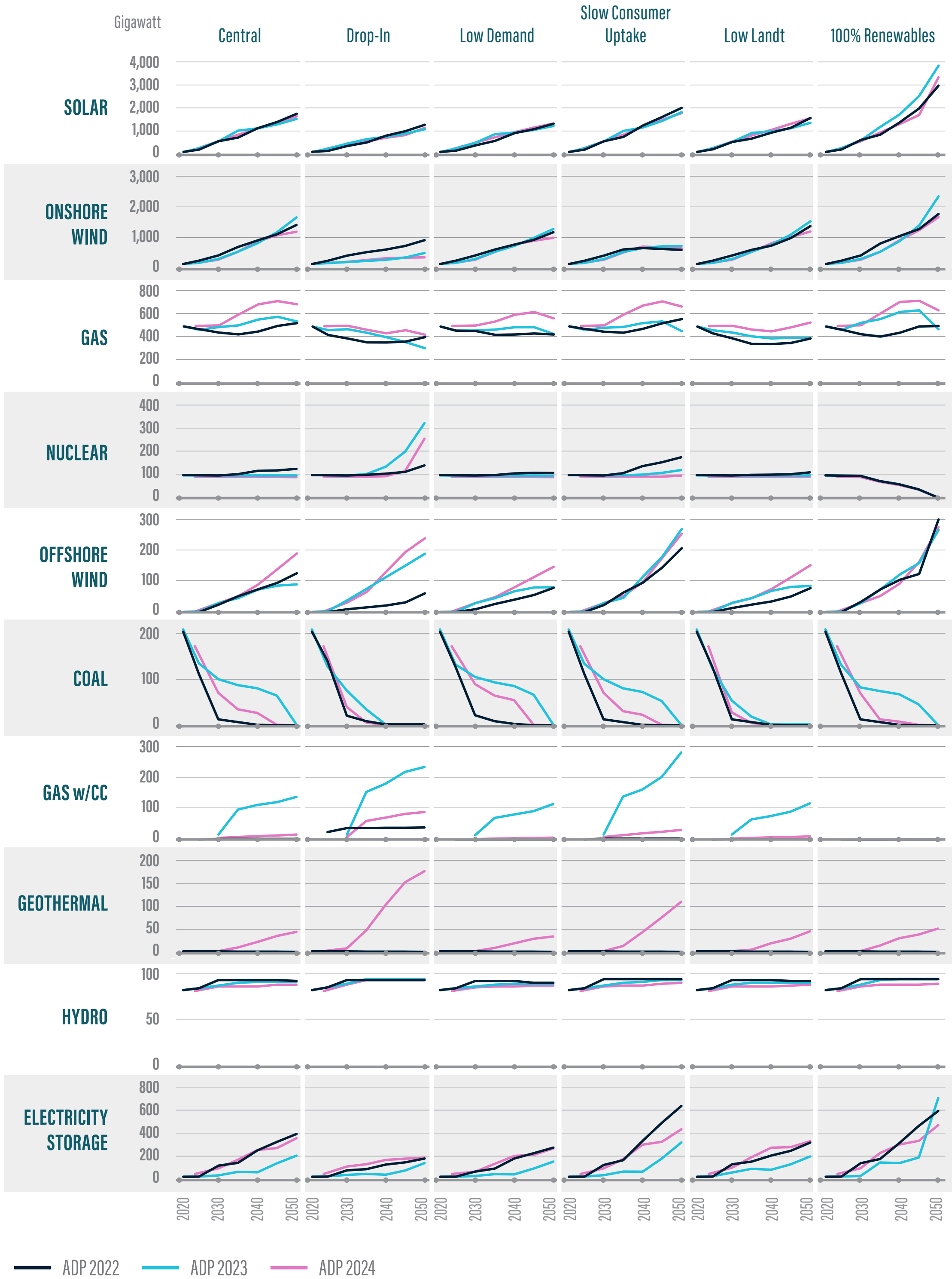
Solar capacity has remained relatively similar across years, while onshore wind capacity by mid-century has trended down, with *ADP 2024* having the lowest wind capacity so far. This is partly a result of updates made based on recent reported build rates for wind, which have motivated the use of the Limited Access scenario (see section on Solar and Wind Siting for further information) for available wind sites. Expected transmission costs in the modeling assumptions have also increased, further diminishing wind capacity.

Among "clean firm" technologies, the main difference across *ADP* years is the emergence of next-generation geothermal as a generating technology in *ADP 2024*. As described earlier, geothermal out-competes natural gas with CCS in many situations, resulting in a decrease in gas CCS capacity compared to *ADP 2023*. Nuclear capacity remains flat in the Central scenario. Nuclear growth in the Drop-In scenario is still dramatic but is also reduced through competition with geothermal.

Gas without carbon capture remains relatively flat, but it is highest across all scenarios in *ADP 2024*. A major factor in this is higher load growth, especially from data centers. Another is building less gas with carbon capture due to the new competition with geothermal in the modeling. Gas without carbon capture is built instead.

The rate at which coal capacity retires is quite different across the three years of ADP reports, even though actual coal generation has been low in all cases. The differences are the result of assumptions regarding minimum capacity factors, O&M cost and its growth, and operational constraints, all of which affect whether coal capacity can be cost-effectively maintained for reliability, but seldomly run, while other resources are built.

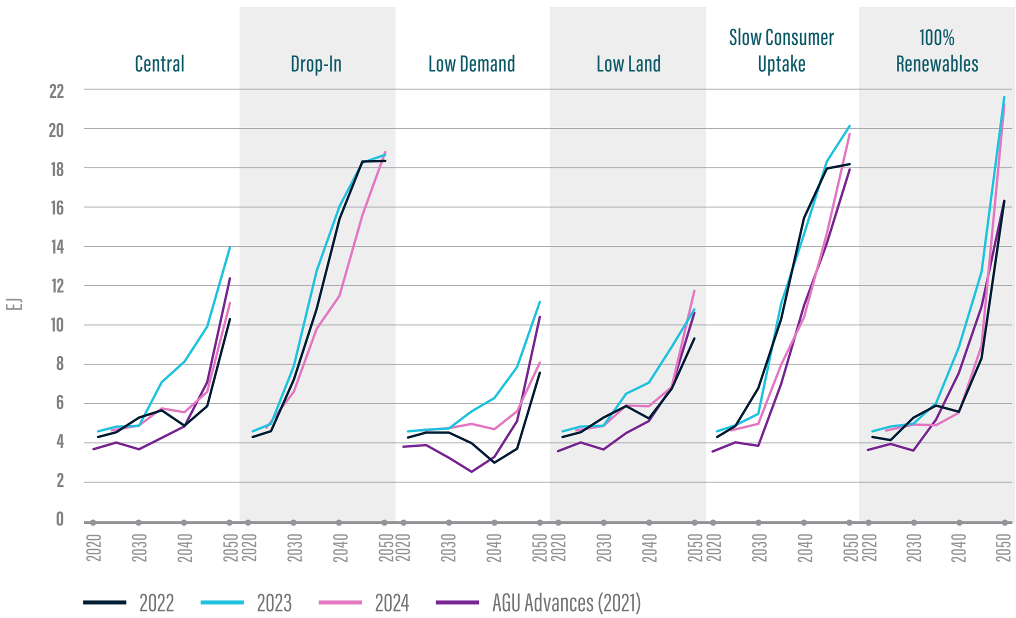
**FIGURE 47.** Comparison of electricity capacity by type across scenarios in ADP 2022, ADP 2023, and ADP 2024



## Biomass

Figure 48 shows biomass demand across scenarios for *ADP 2024, ADP 2023, ADP 2022*, plus results from our analysis in *AGU Advances* from 2021 (completed in 2020) that is the predecessor to the ADP series. The figure shows that biomass use by scenario is roughly similar across years, and that it is the technology choices, land-use constraints, and other factors within the scenarios themselves that have the largest impact on biomass use variability. That said, biomass use in the Central scenario fell from 14 EJ last year to 11 EJ year, driven by changes in biomass applications and the connections between hydrogen production and biomass.

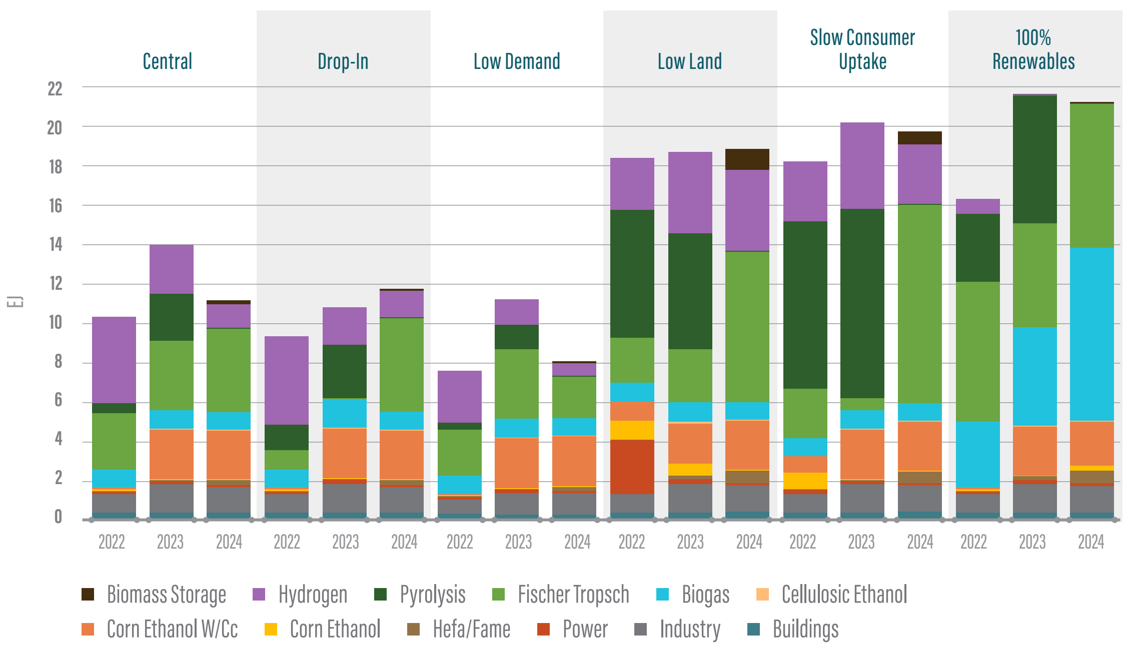
**FIGURE 48.** Comparison of biomass demand across scenarios in AGU Advances 2021, ADP 2022, ADP 2023, ADP 2024




Some of the underlying dynamics can be seen in Figure 49, which shows the uses in 2050 of biomass, largely as in input to fuel production, in the three ADP reports. Use of biomass for producing hydrogen has trended steadily downward in the Central and most other scenarios down as the cost of obtaining carbon-free hydrogen from other sources has fallen. Pyrolysis essentially vanishes in all scenarios in *ADP 2024* because of technology updates in our modeling, and is largely replaced by Fischer Tropsch, while HEFA/FAME for biodiesel production increased across years. Corn ethanol, both with and without CCS, is maintained at about the same levels in *ADP 2024* as last year, but with the final application changing to jet fuel production over time, as described in *ADP 2023*. Many application technologies for liquid fuels have similar characteristics.

Finally, across scenarios and years, very little biomass is used in the power sector. Power plant BECCS, a mainstay of negative emissions in earlier integrated assessment modeling and IPCC reports, is not found to be economic in our modeling. This is because BECCS power cannot find enough run-hours when wind and solar are not on the margin, and therefore, utilization rates are low and high capital cost is spread over too few hours. Instead, by producing liquid fuels or hydrogen, both of which are much cheaper to store than electricity, BECCS can find better economics.

**FIGURE 49.** Biomass use by type in 2050 across scenarios in ADP 2022, ADP 2023, and ADP 2024



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# VIII SUPPLEMENTAL RESULTS

## Scenario Results

### Primary energy

**FIGURE 50.** Primary energy consumed domestically across scenarios

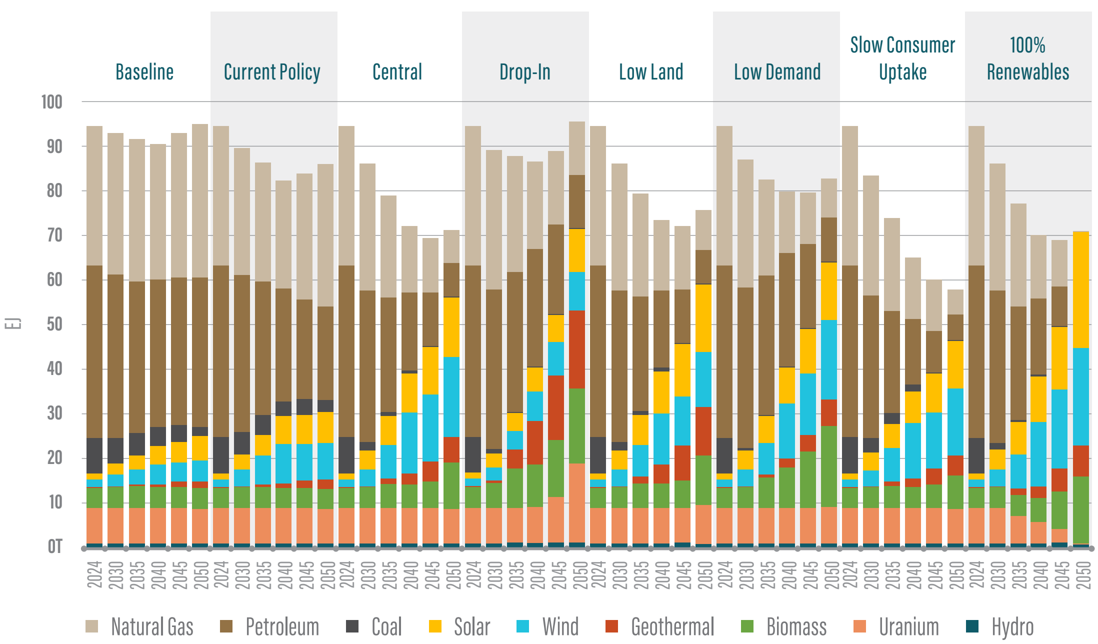
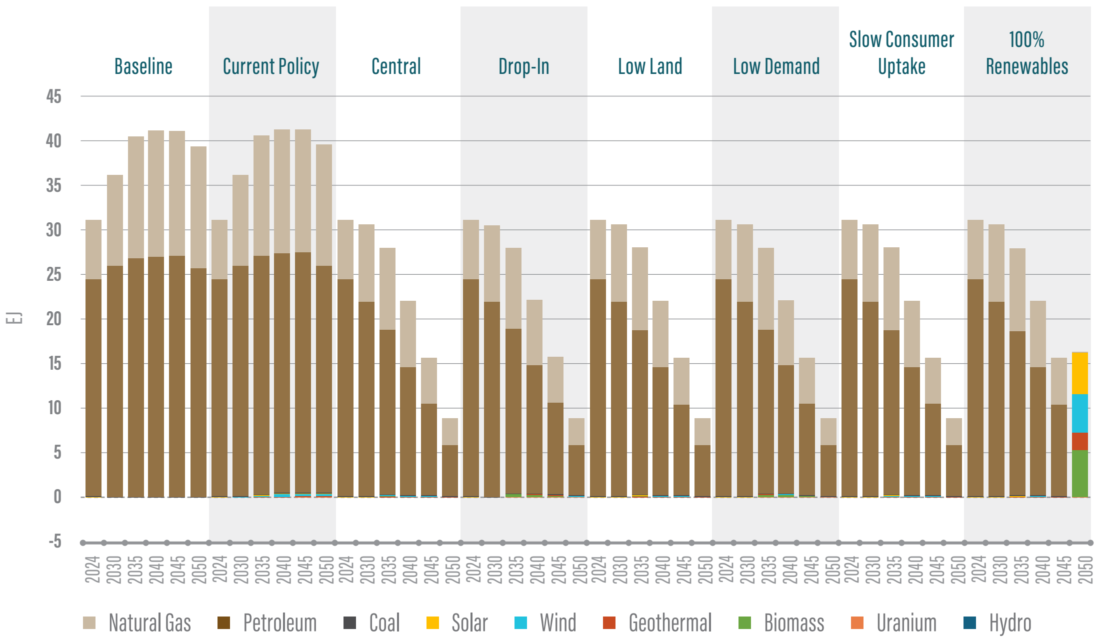


**FIGURE 51.** Primary energy represented in energy exports across scenarios




## Final energy

**FIGURE 52.** Final energy demand by fuel type

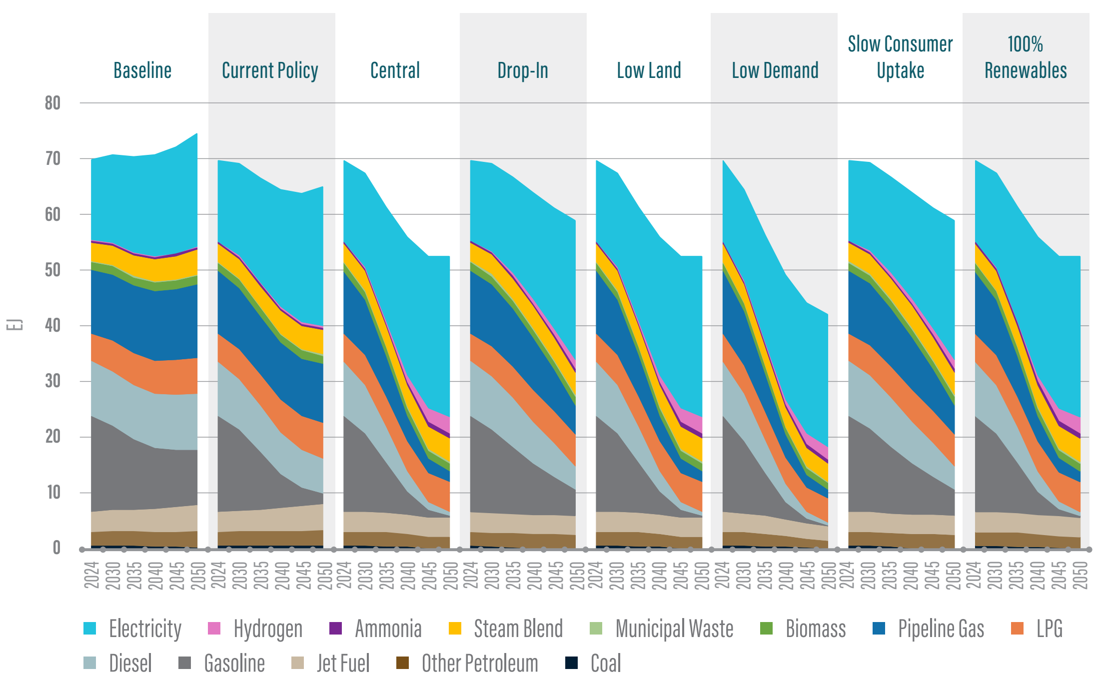
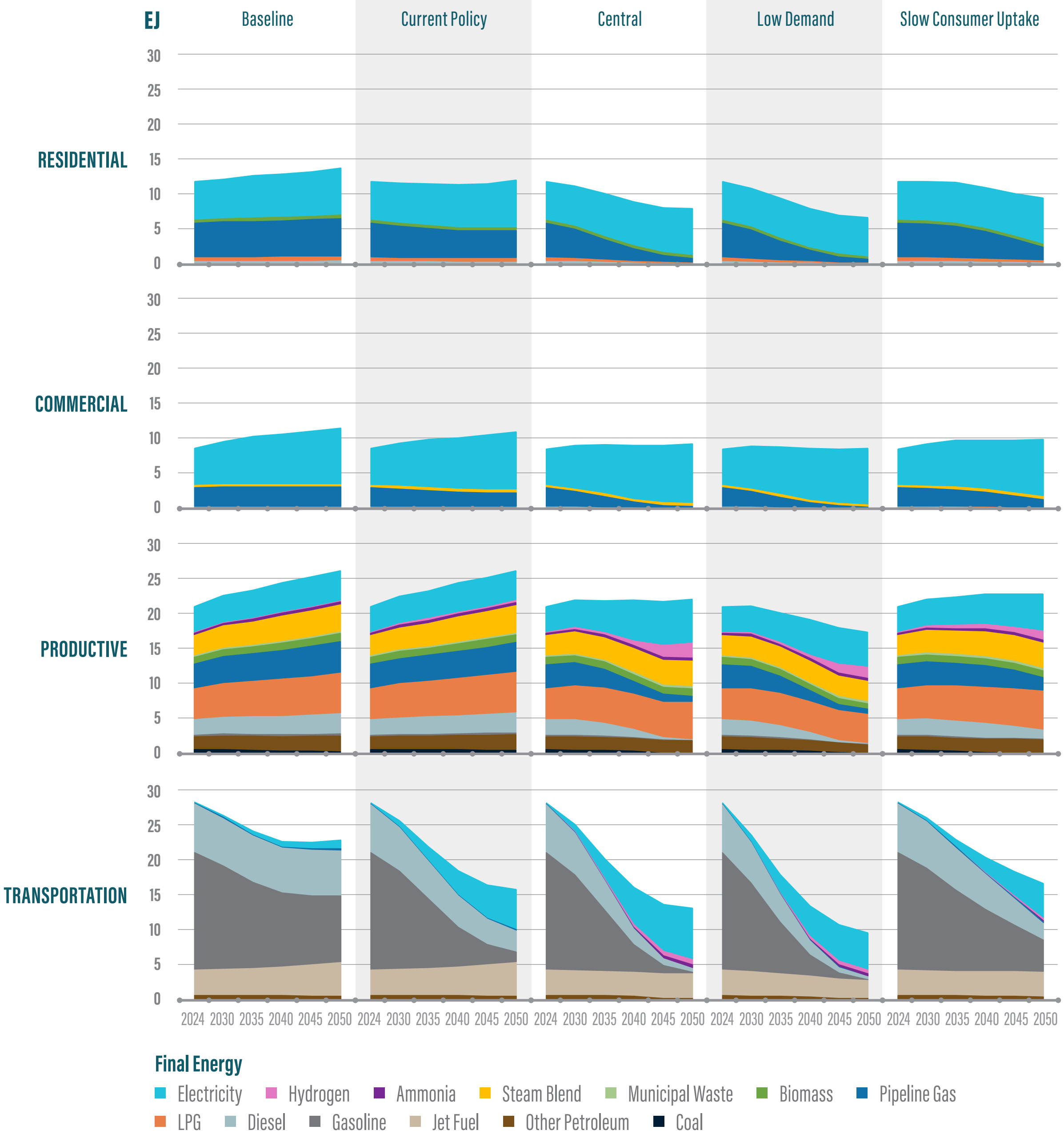
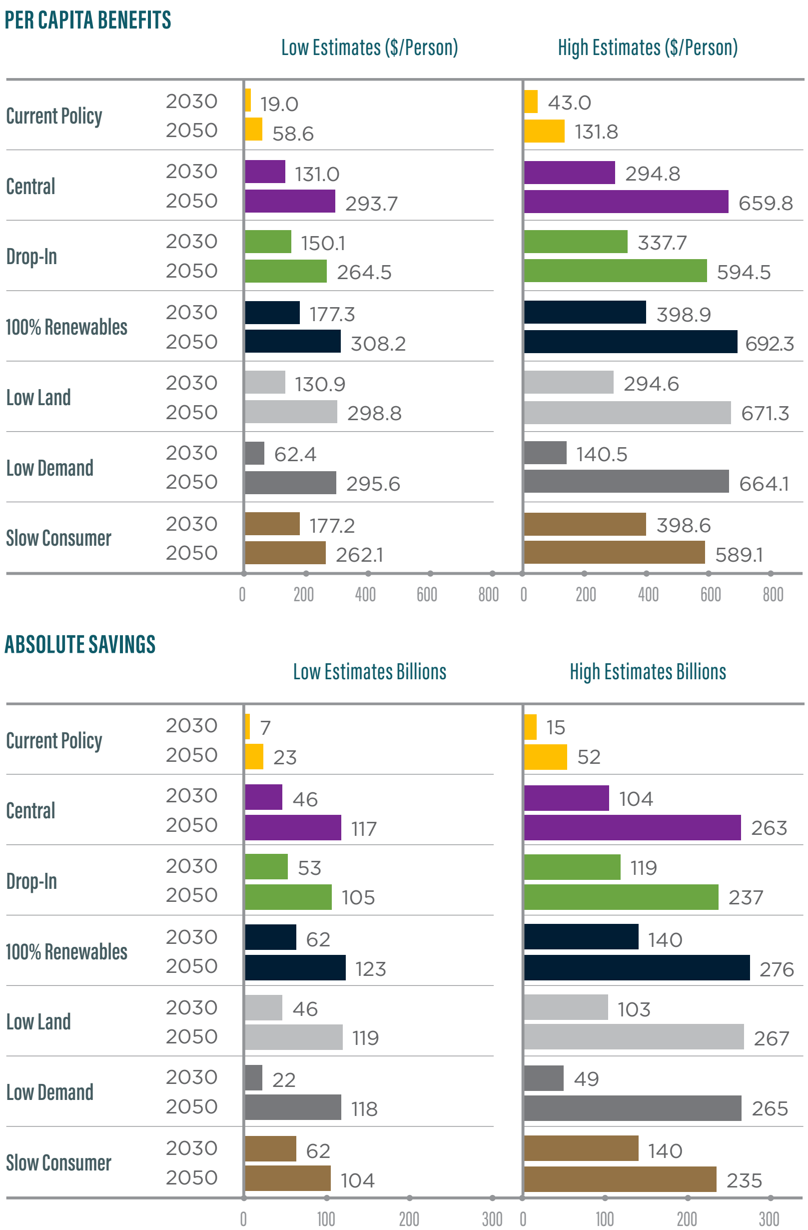


**FIGURE 53.** Final energy by sector



## Health benefits

**FIGURE 54.** Health benefits from reductions in air pollution relative to the reference scenario



## Demand Technologies

**FIGURE 55.** On road transportation vehicle stock

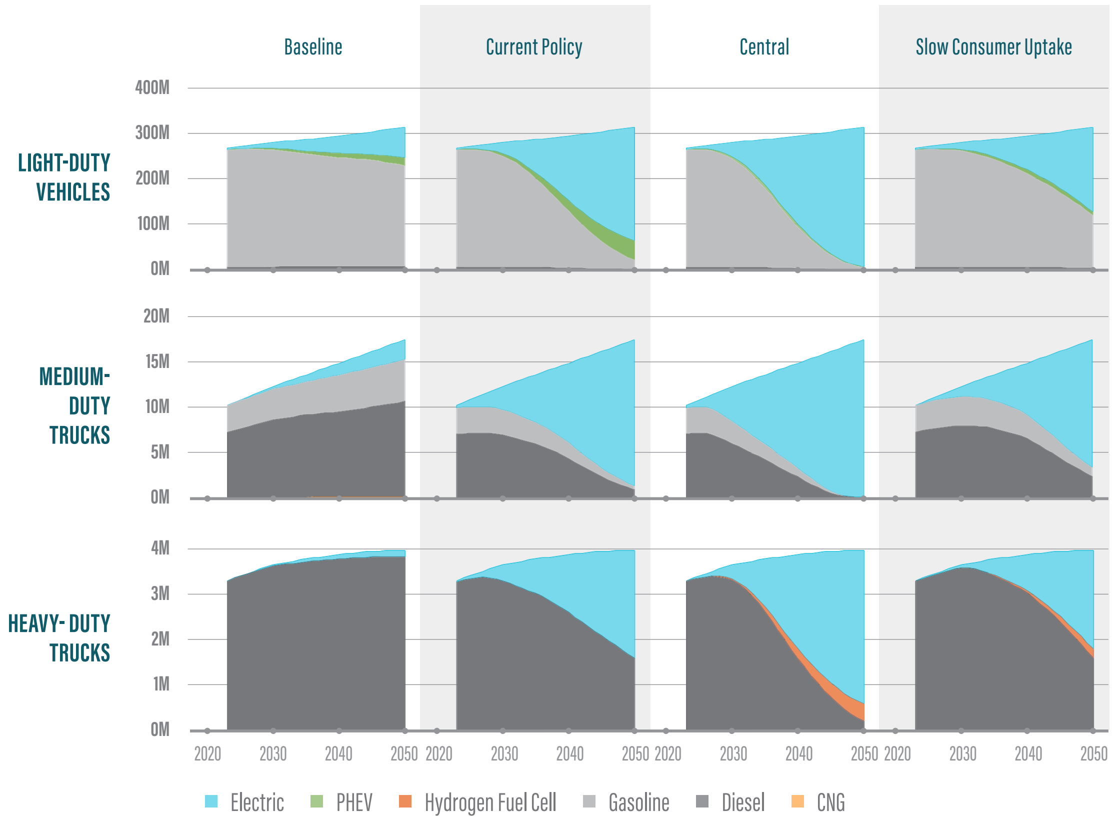
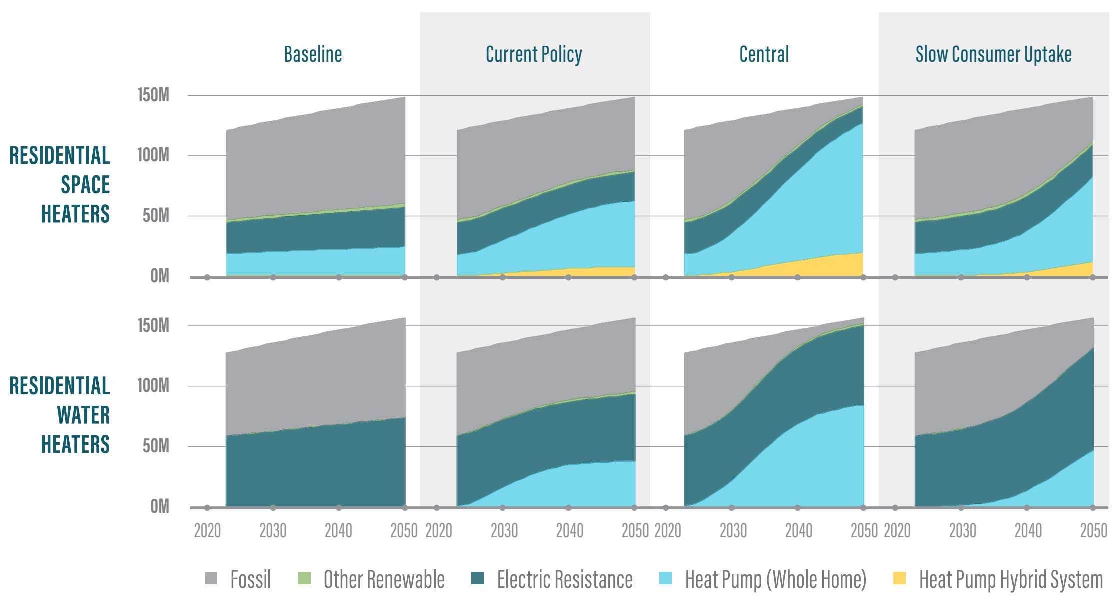
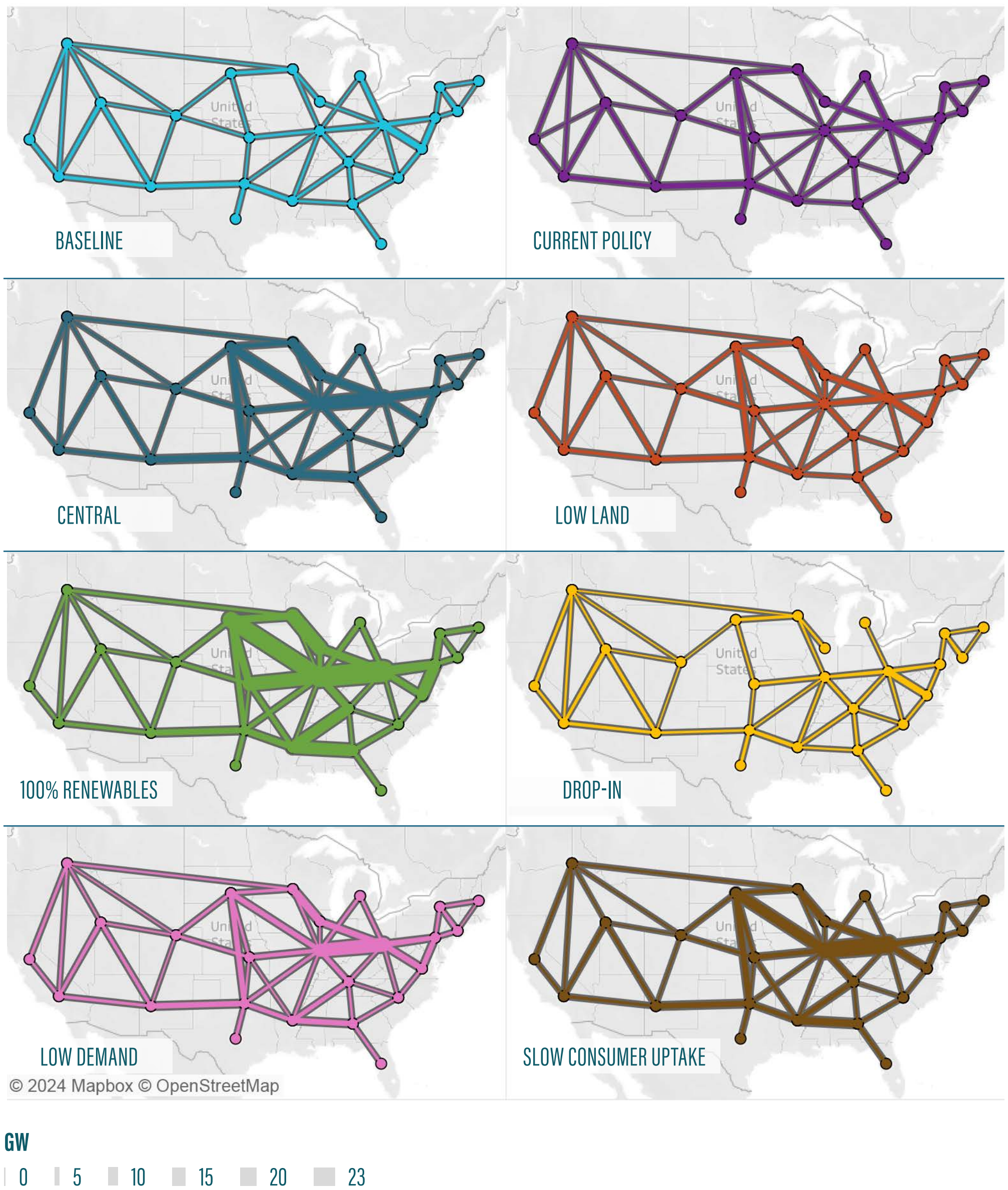



**FIGURE 56.** Residential building heating technologies



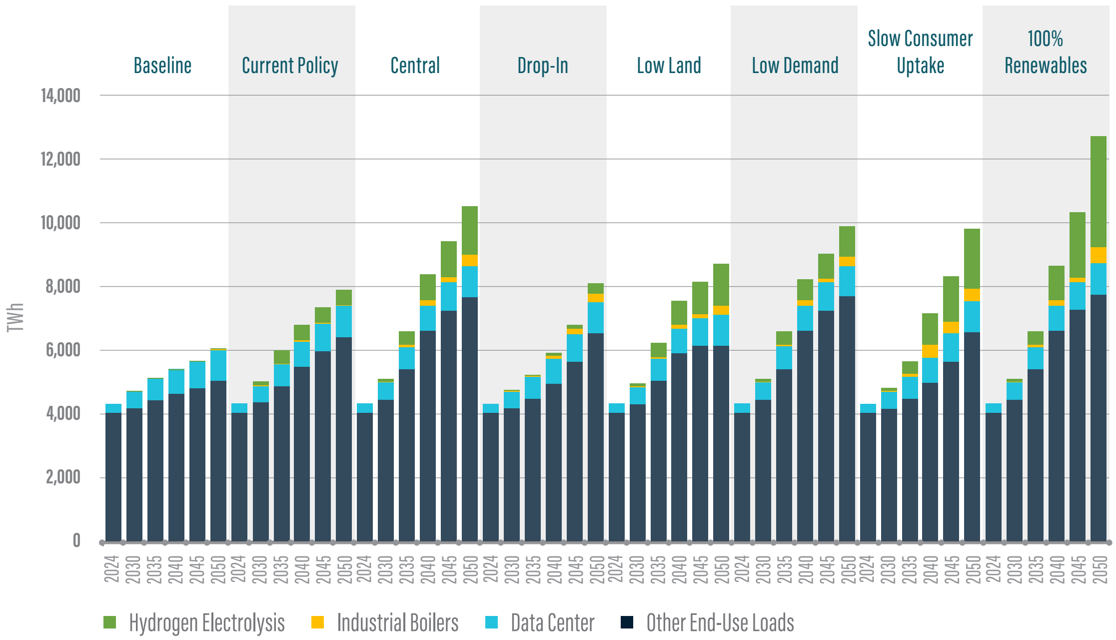
## Electricity

**FIGURE 57.** 2050 Electric Transmission Capacity



## Electric load

**FIGURE 58.** Electric Load




## Hydrogen

**FIGURE 59.** Hydrogen Production

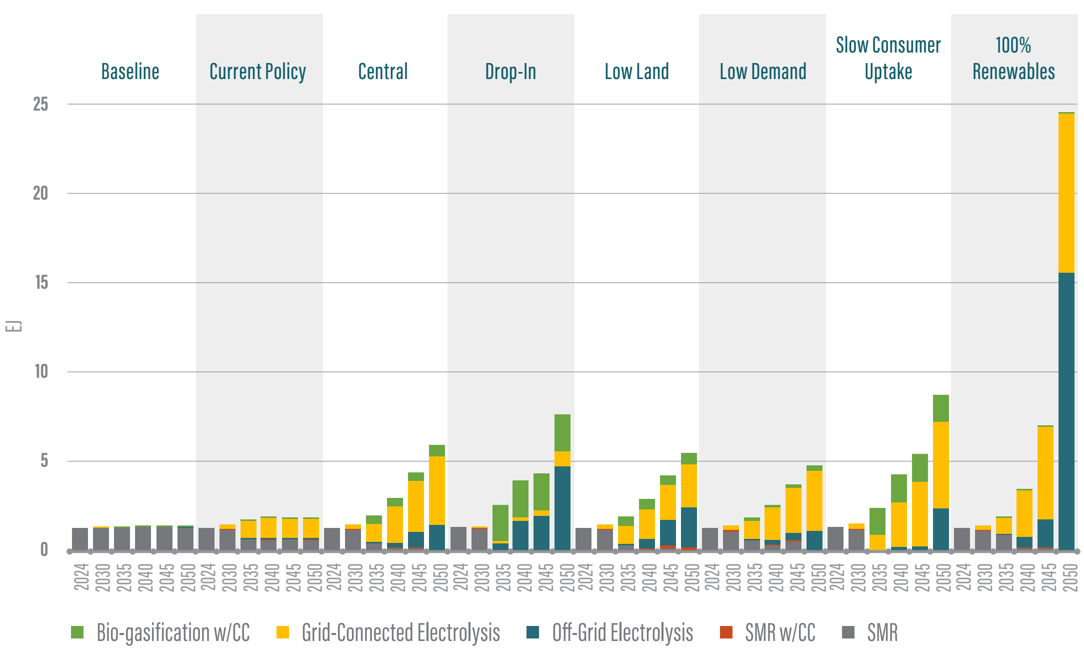


**FIGURE 60.** Hydrogen Consumption

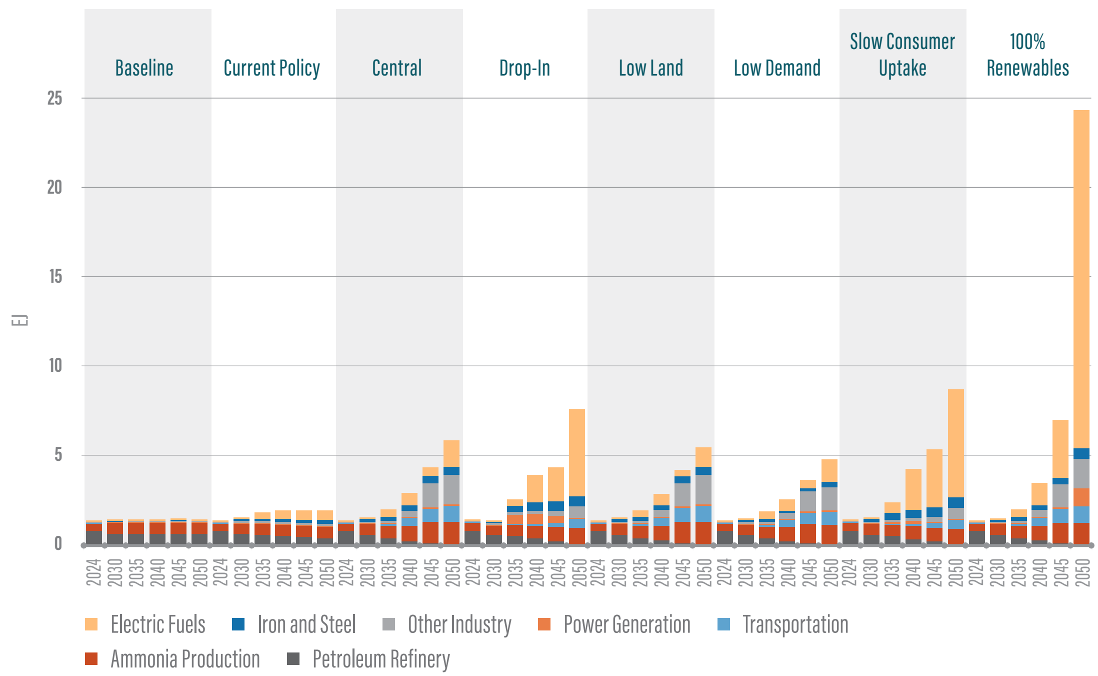


**FIGURE 61.** 2050 hydrogen pipelines comparisons between scenarios. Pipelines smaller than 500 MW capacity have been removed from the visual.

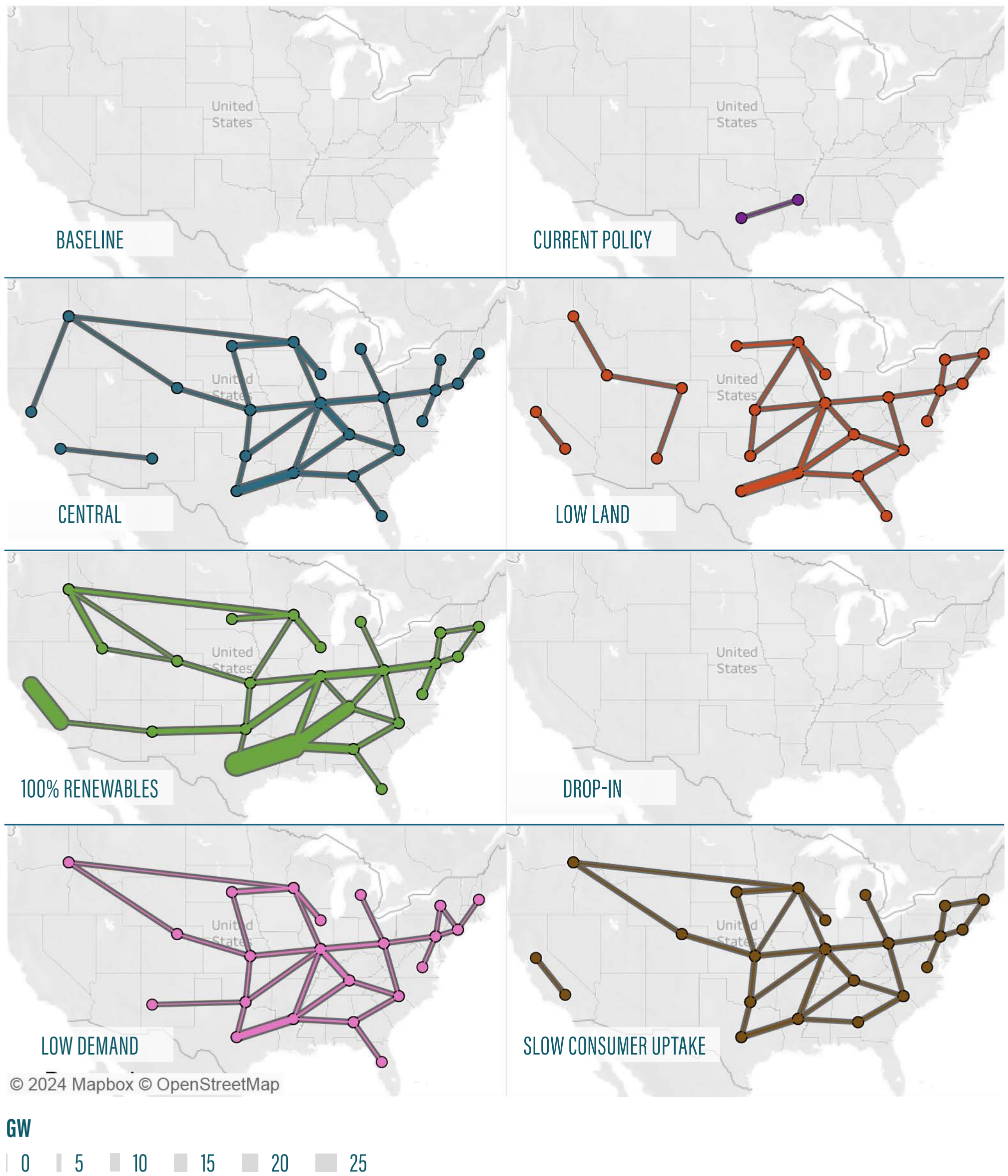
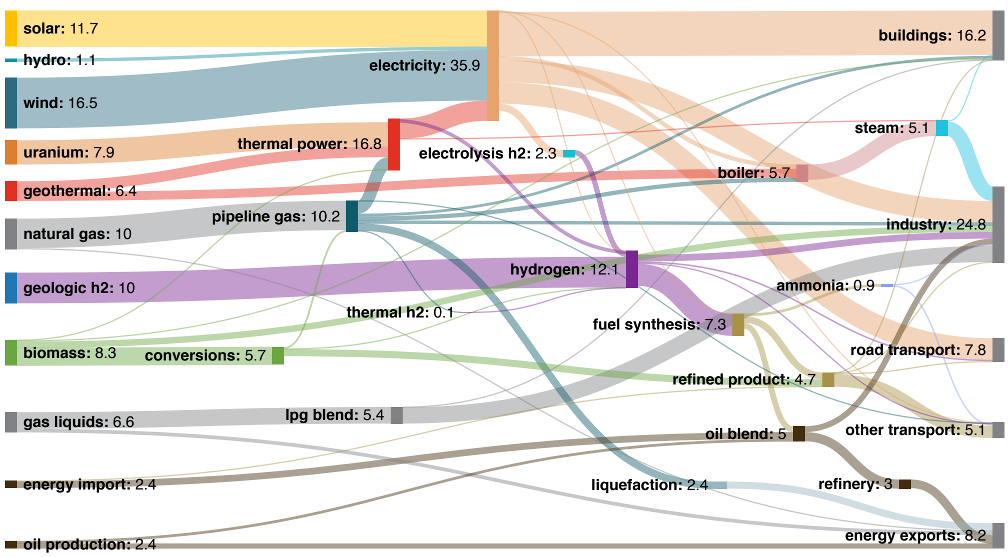


**FIGURE 62.** Sankey Diagram for 2050 Central w Geologic Hydrogen (Exajoules)




## CCUS

**FIGURE 63.** Carbon Capture Application

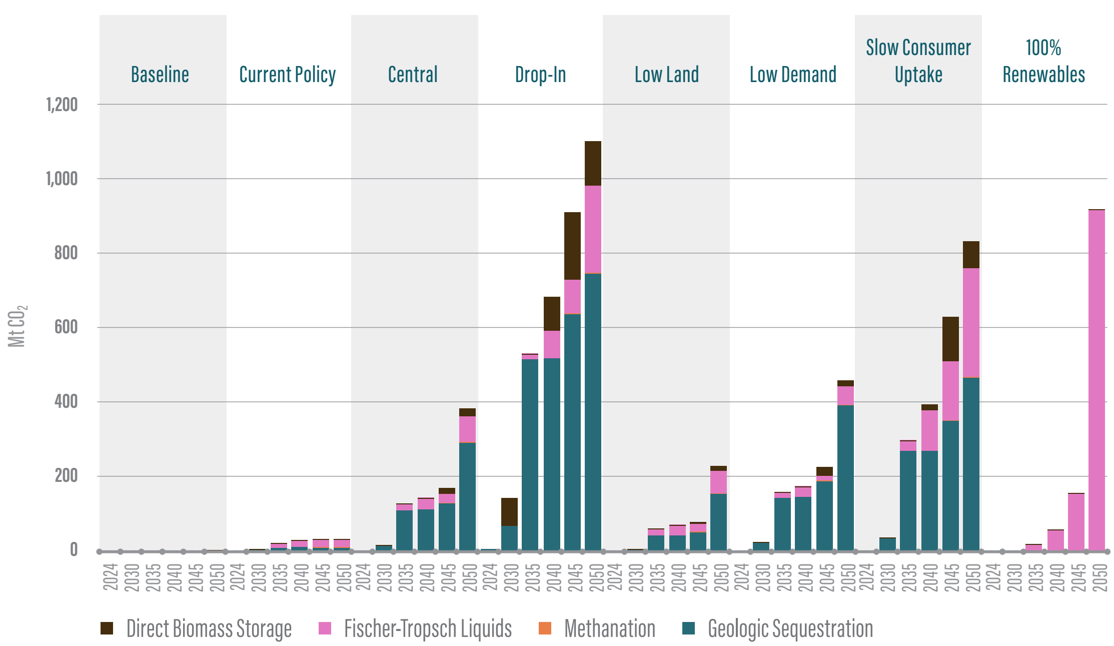


**FIGURE 64.** Carbon Capture Source

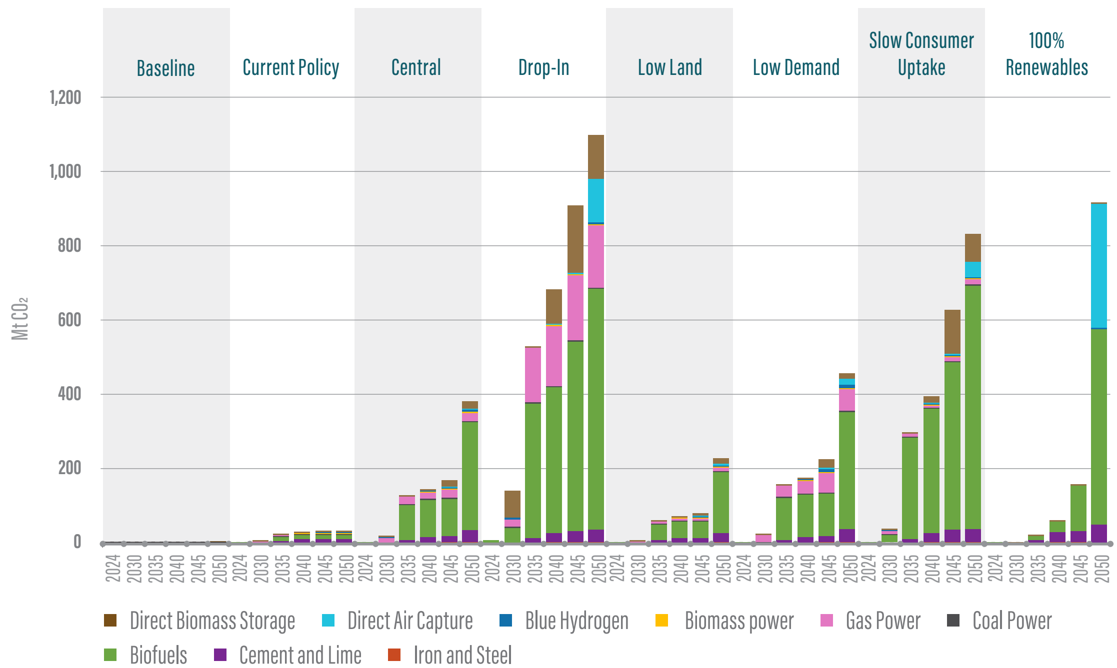
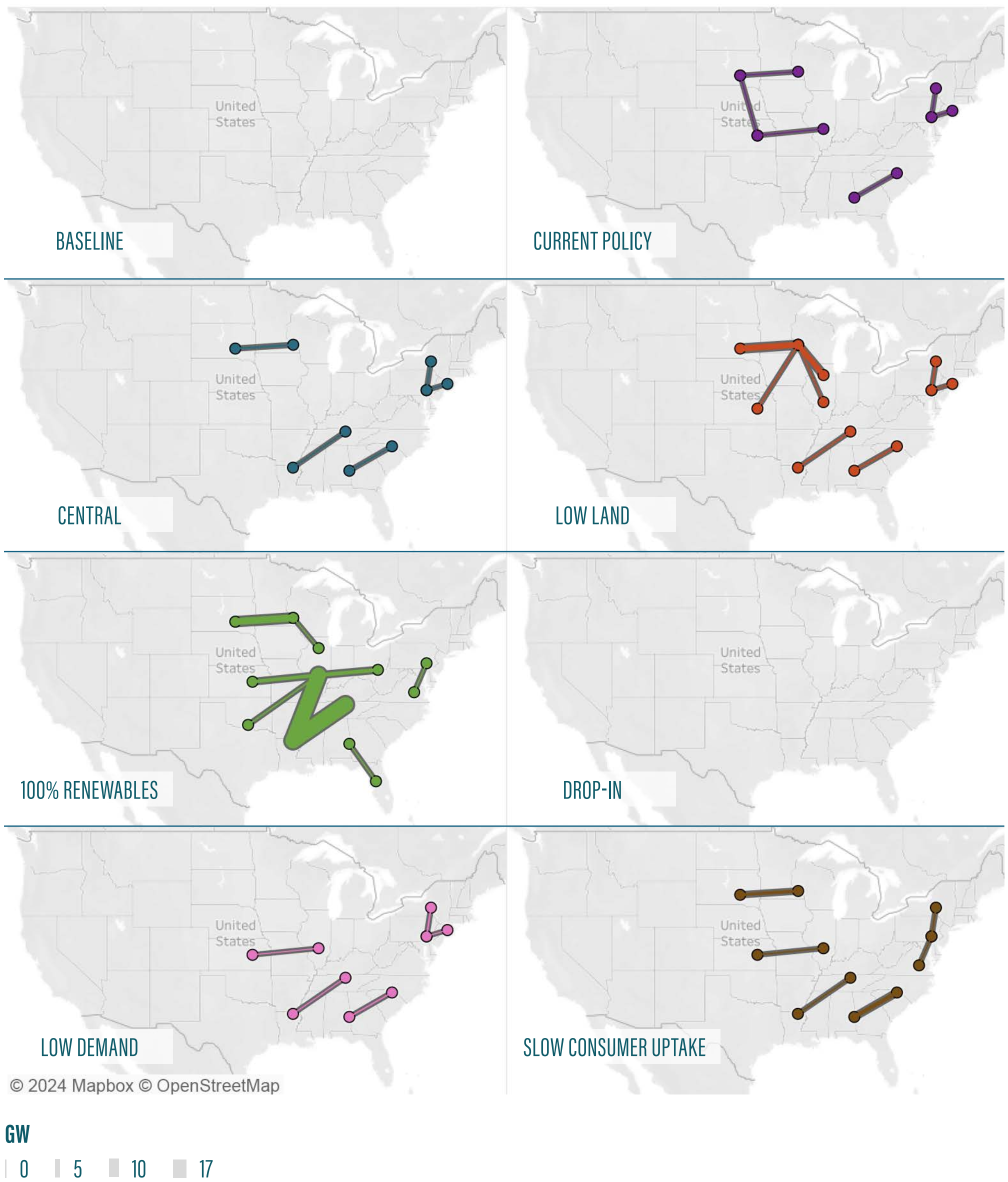


**FIGURE 65.** $CO_2$ Pipeline Capacity in 2050



## Hydrocarbon fuels

**FIGURE 66.** Hydrocarbon fuel supply

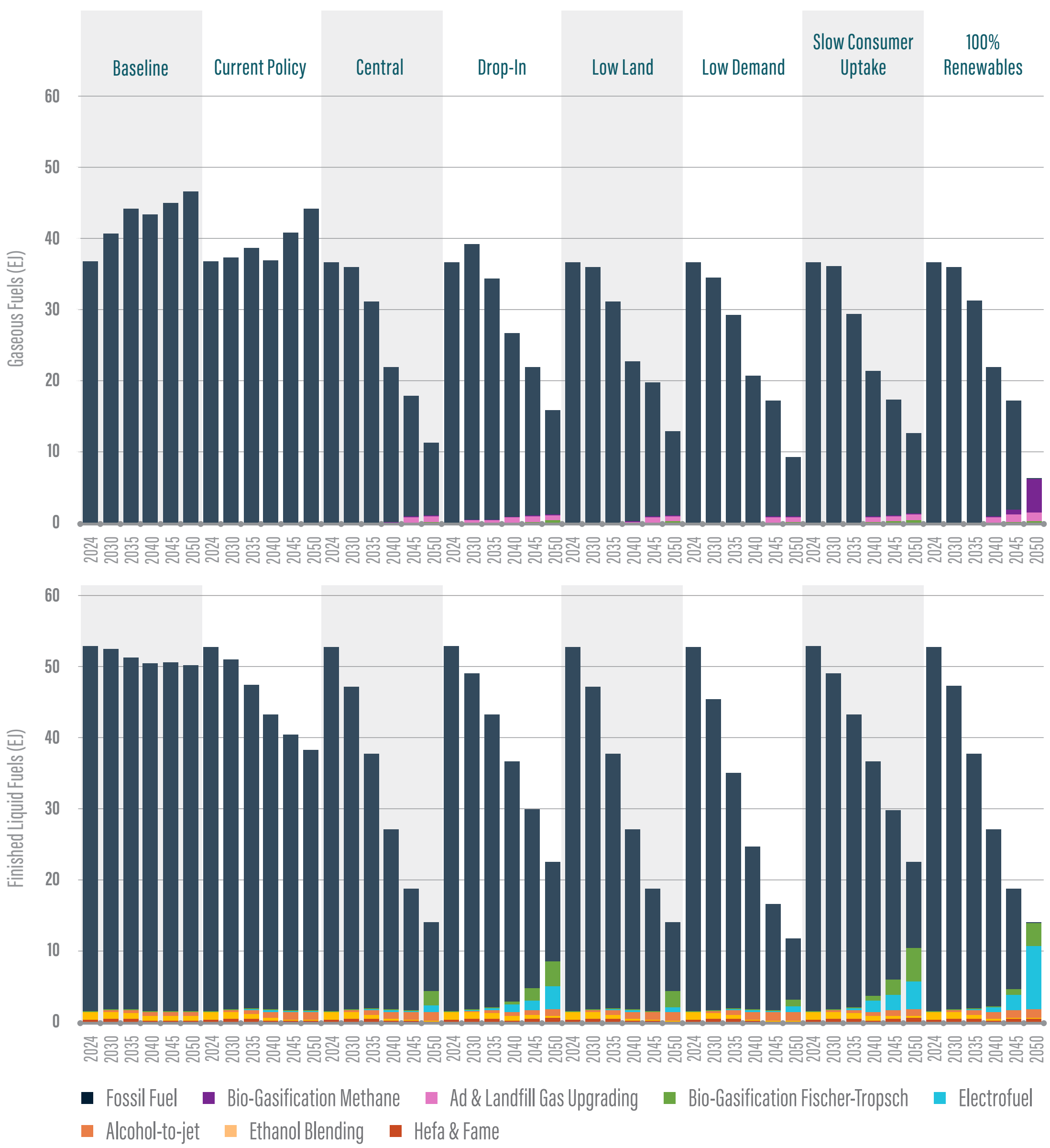


**FIGURE 67.** Hydrocarbon fuel use

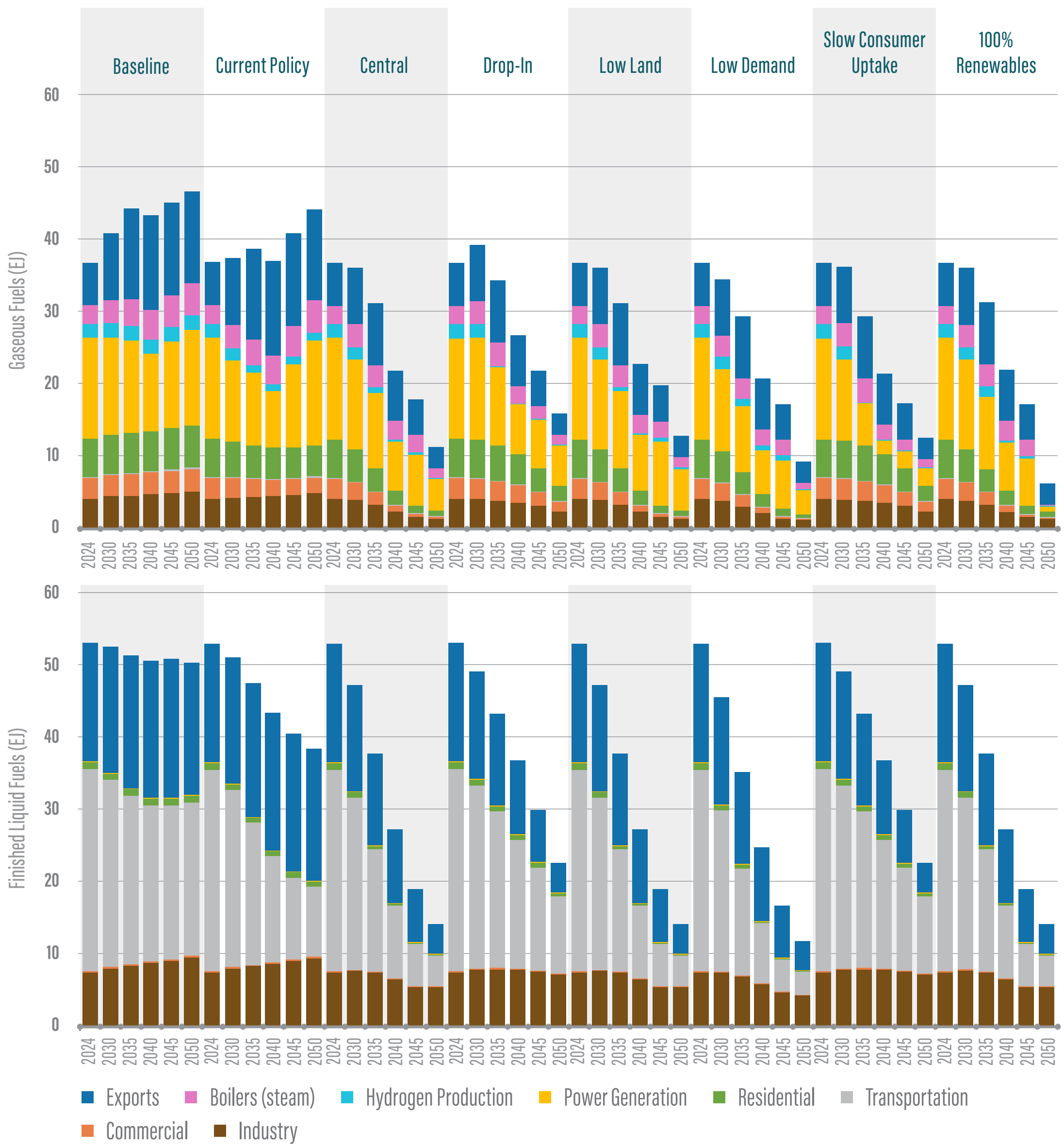


**FIGURE 68.** Liquid hydrocarbon production capacity

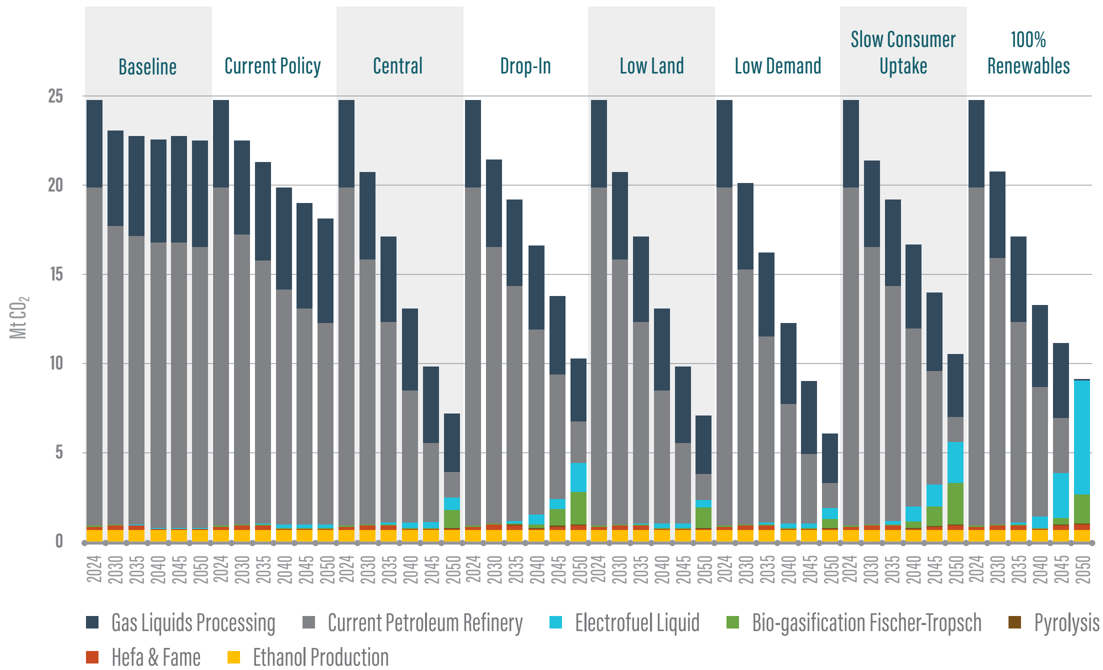
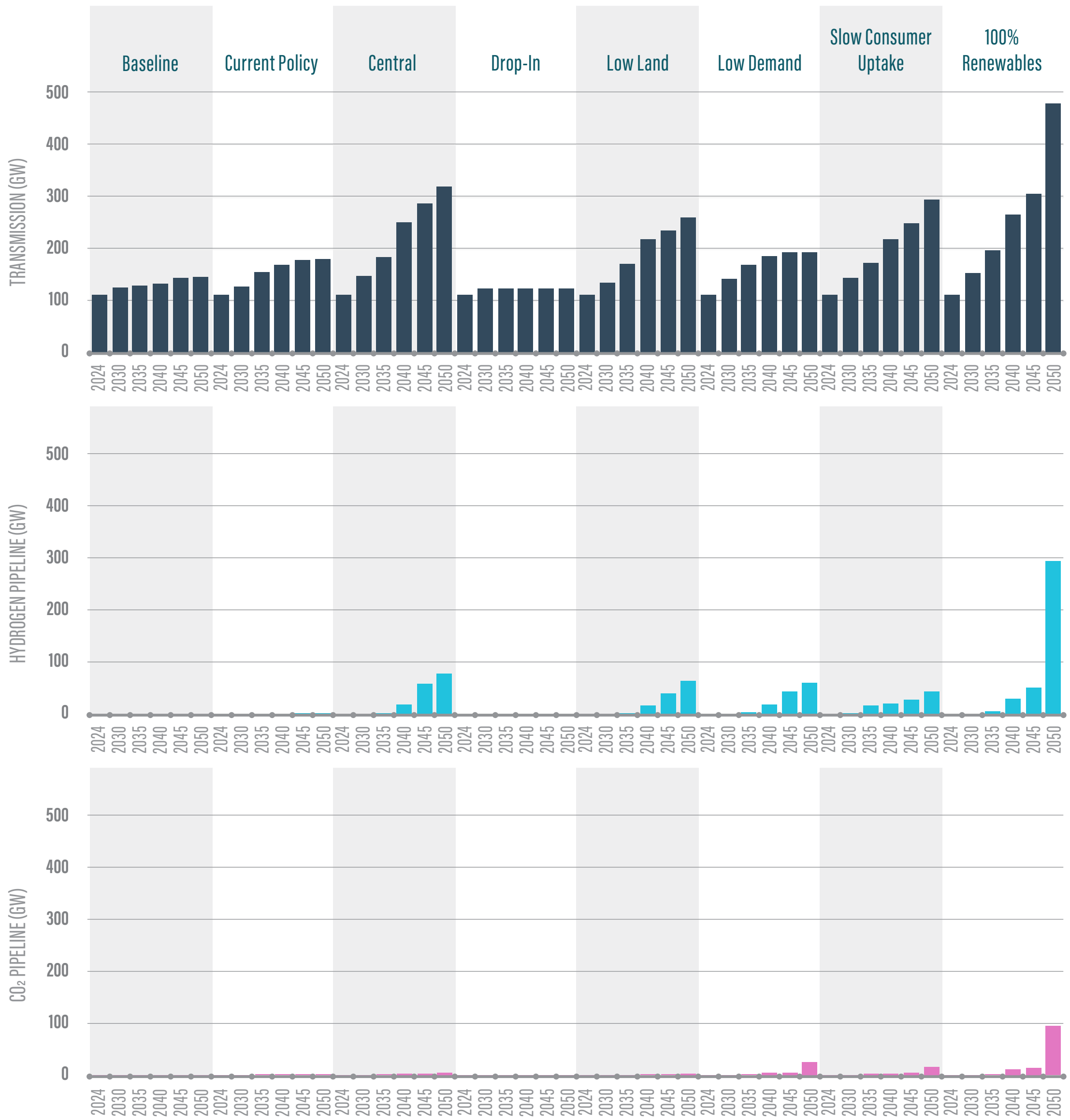
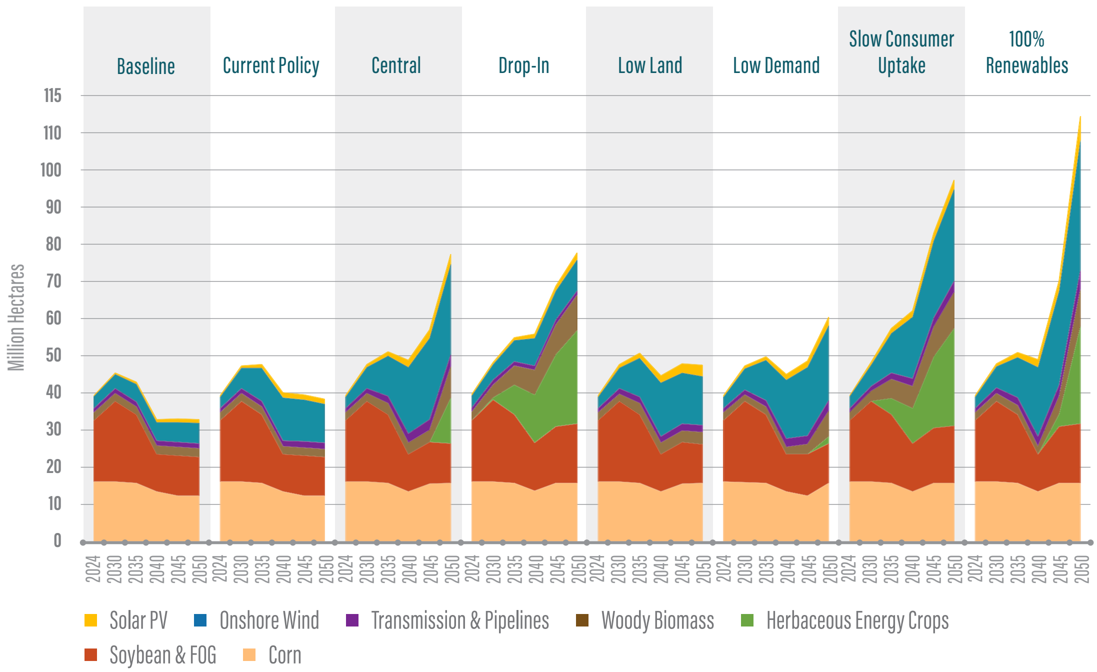


**FIGURE 69.** Energy transport capacity: electricity transmission, hydrogen pipeline, and $CO_2$ pipeline



## Land Use

**FIGURE 70.** Land Use for Energy Infrastructure



# Sub-Annual Snapshots

## Electricity Operations

**FIGURE 71.** Generation share of U.S. electricity by day of the year and scenario

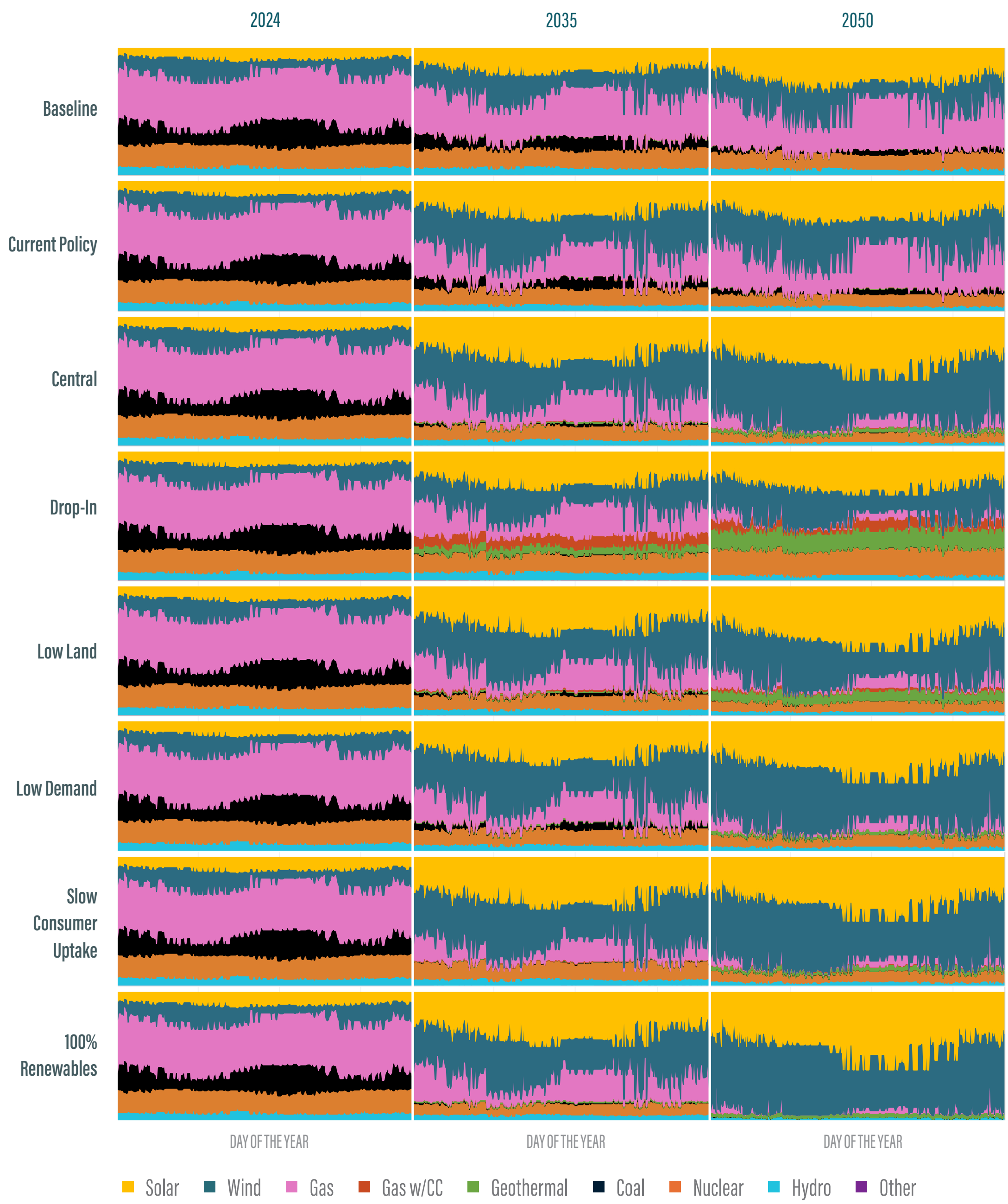
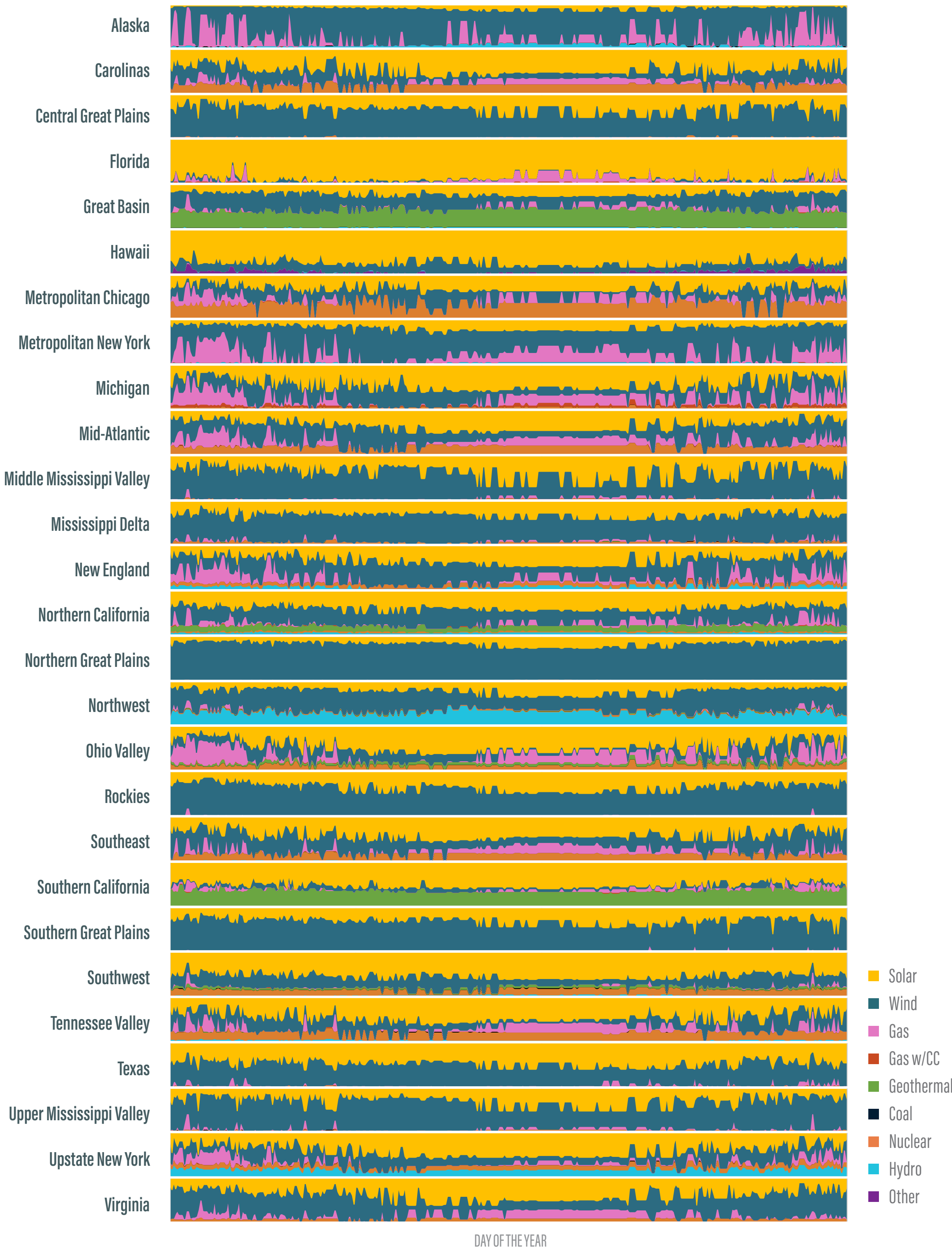


**FIGURE 72.** Central scenario generation share of U.S. electricity by day of the year and zone



## Hydrogen Production and Use

**FIGURE 73.** U.S. hydrogen production share by day of the year and scenario

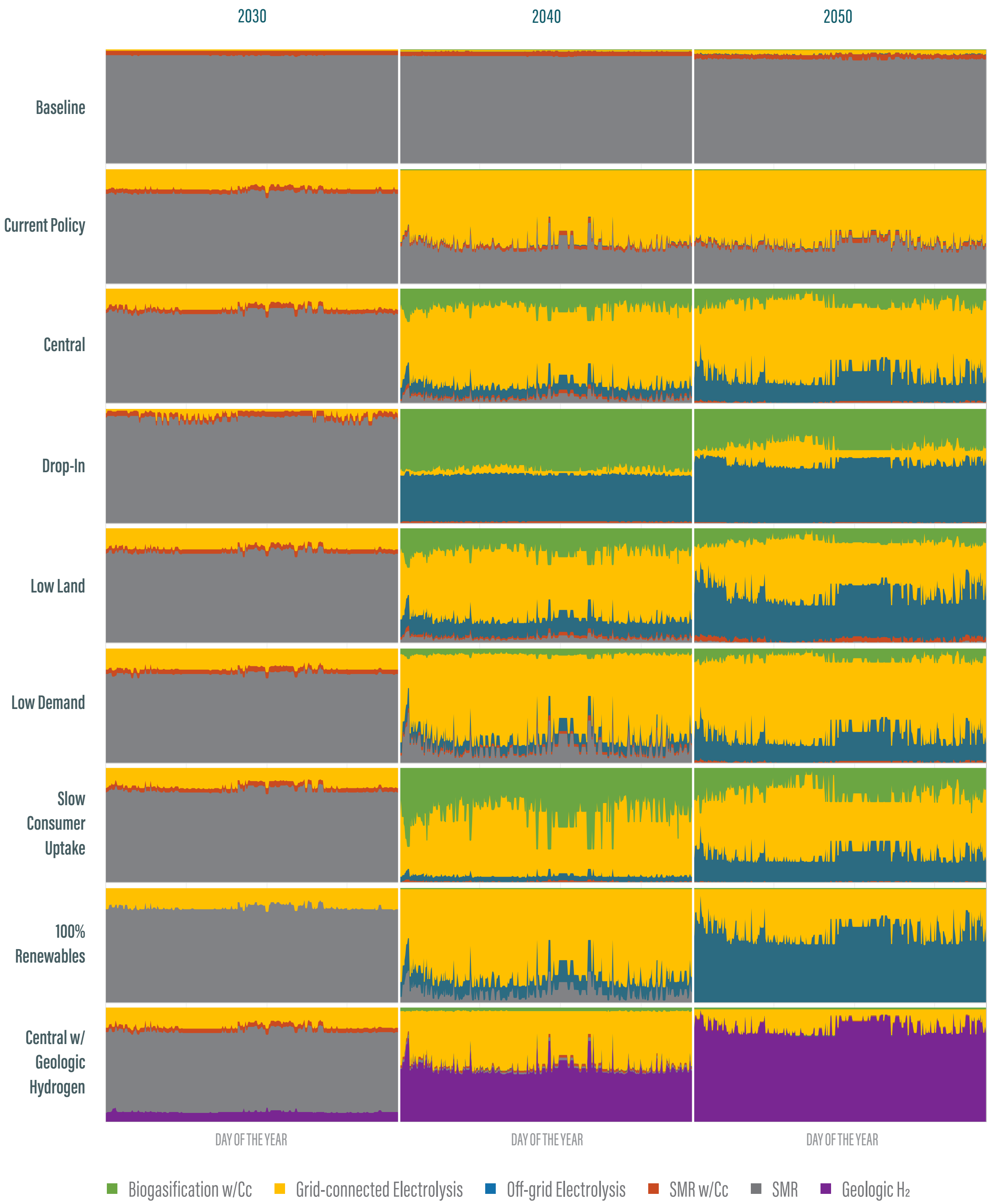


**FIGURE 74.** U.S. hydrogen consumption share by day of the year and scenario

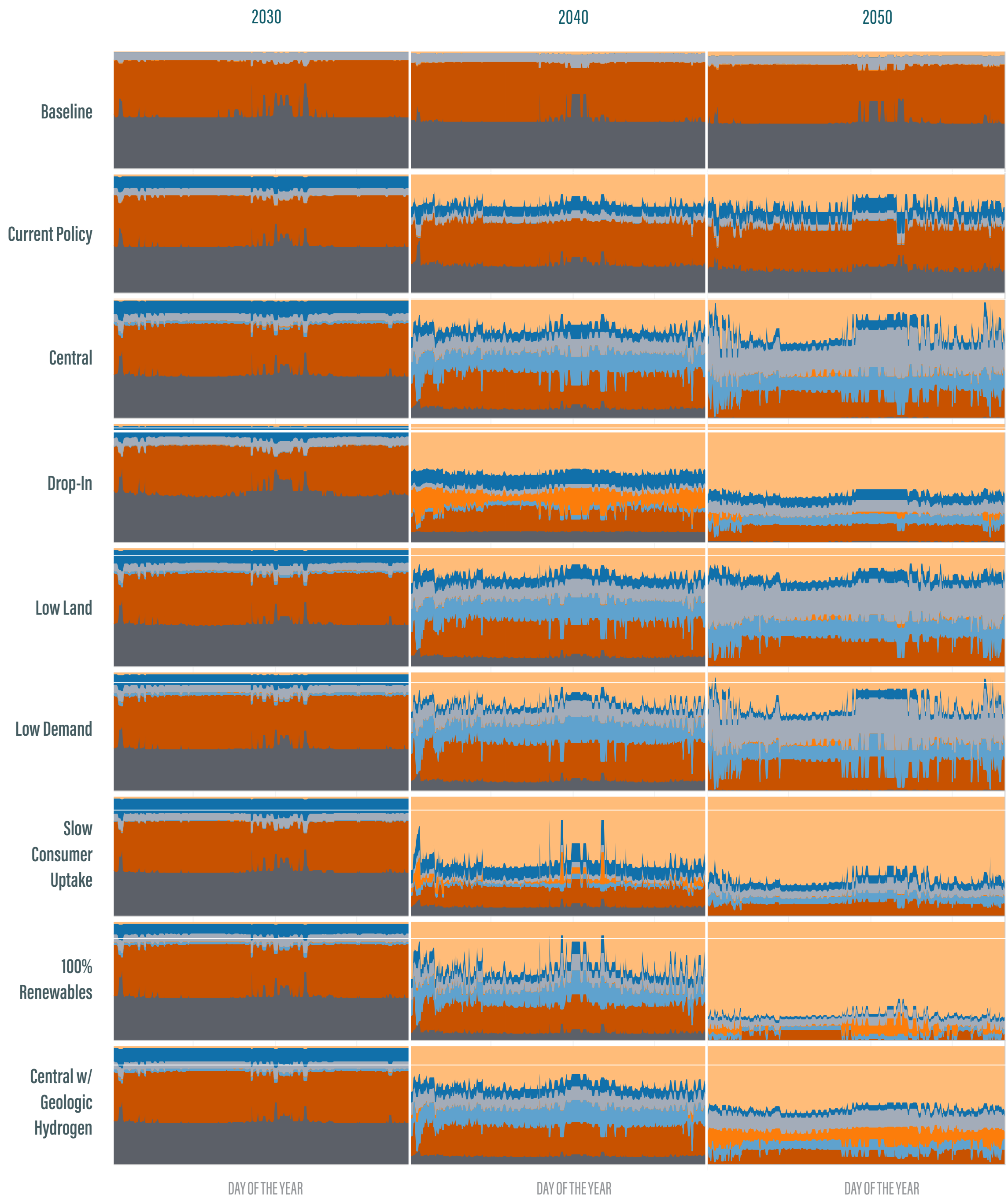
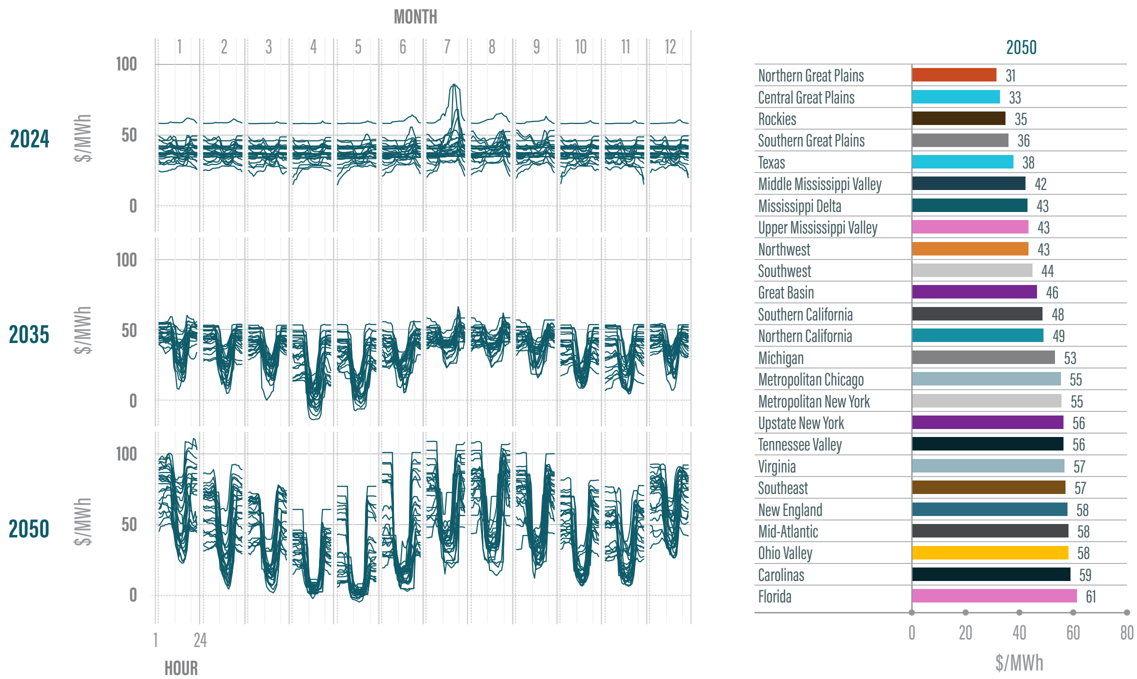


**FIGURE 75.** Marginal electricity prices by month and hour across zones



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