CLIMATE LEADERSHIP COUNCIL

The Climate Leadership Council's Emissions, Revenues, and Technology ("CERT") Model

Methodology Memorandum

February 2024

Introduction

This memorandum summarizes the approach of the Climate Leadership Council's Emissions, Revenues, and Technology ("CERT") model. CERT and its workings are designed to analyze the impacts of a federal, economywide carbon price as articulated by the Baker-Shultz Carbon Dividends Plan.[1] CERT can further be used to assess other interventions changing the relative prices of existing and emerging technologies on energy markets.

CERT relies on modeling techniques projecting energy use and technology mixes, greenhouse gas("GHG") emissions, and federal revenues. It is an evolution of the analytical tools available from Thunder Said Energy ("TSE").[2] TSE is a consultancy specializing in data, insights, and modeling for policy researchers and market participants.

The Council updated and expanded these tools to improve their comparability with consensus market outlooks, such as the Annual Energy Outlook ("AEO")[3] published by the U.S. Energy Information Administration ("EIA").[4] CERT also explores the electrification of residential and commercial heating demand, its effect on load, and interactions between renewable capacity, energy storage, and thermal dispatch on wholesale power markets.

This methodology memorandum provides an overview of assumptions, data, and modeling techniques sourced from TSE and other market outlooks. After that, it discusses the bespoke enhancements made by the Climate Leadership Council ("CLC") to generate a more specific analysis of electricity markets and technology deployment in CERT.

CERT Overview

The foundation of CERT is a series of interlinked technology deployment models describing contemporary U.S. energy markets and how energy supply and energy demand will evolve throughout time with economic and demographic changes and deployment of existing and emerging technologies (e.g., small modular reactors or "SMRs,"[5] etc.). CERT assumes the demand for "energy services" across the U.S. economy (e.g., residential power, the industrial sector, the aviation sector, etc.) alongside options for supplying energy as fossil fuels or electricity.

CERT examines how these supply and demand interactions respond to carbon pricing. Many core assumptions, data, and techniques were adapted from an analysis of U.S. energy markets and their potential response to carbon pricing completed by TSE.[6]

The growth of energy demand in CERT is based on high-level macroeconomic performance as measured by U.S. gross domestic product ("GDP") growth, U.S. population growth, and primary energy intensity as defined by the International Energy Agency ("IEA").[7]

Energy demand is met in CERT by energy supply through a mixture of direct fossil combustion (e.g., home heating with gas, cars with internal combustion engines or "ICEs," etc.) or through delivery of electric power. Electricity can be generated by numerous technologies, such as the fleet of thermal plants burning coal, natural gas, or distillate fuel oil ("DFO"). Zero-carbon plants include hydroelectric dams, the legacy nuclear fleet or SMRs, wind, and solar. The potential for large-scale battery storage is also part of the structure of CERT.

Based on the profile of energy supply, CERT projects carbon dioxide ("CO_2"), methane, and other GHG emissions. CERT includes a concept of "negative emissions" like natural sinks (e.g., land-use changes inducing carbon sequestration, etc.), carbon capture and storage ("CCS"), and direct air capture ("DAC") of ambient GHG in the atmosphere.

Introducing a climate-related policy like a carbon fee induces CERT to project a different future for energy supply and energy demand compared to a "baseline scenario." With data from TSE, CERT has a set of existing and emerging technologies it can deploy to minimize energy costs while satisfying the same ultimate level of demand for energy services. Without a policy change, CERT can either not deploy a technology at all (especially emerging ones) or only deploy at a minimum level (e.g., 8,000 megawatts or "MW" of wind builds per year).

With a price on carbon introduced, CERT models emerging technologies becoming economical sooner (e.g., geological CCS, etc.) and existing technologies being economical to deploy at a larger scale. For instance, the 8,000 MW of wind builds per year might increase to 12,000 MW per year because a carbon fee induces more load via electrification and makes the economics of wind in power markets look more attractive to investors and utilities.

This list shows the GHG-reducing technologies the CERT model imports from TSE:

- **Power Sector**
  - Onshore Wind
  - Offshore Wind
  - Solar Photovoltaic ("PV")
  - Coal-to-Gas Switching[8]
  - SMRs
  - Hydrogen Power
- **Transportation Sector**
  - Electric Vehicles (specifically light-duty vehicles, like cars and trucks)
  - Hydrogen Cars
  - Electric Railways
  - Biofuels
  - Renewable Diesel
- **Heating Demand**
  - Biogas
  - Hydrogen Heat
  - Solar Heaters
- **Industrial Sector**
  - Mitigating Methane
  - Industrial Efficiencies
  - CO_2-Cured Concrete
- **CCS**

- Oxy-Combustion Process[9]
- Carbonate Fuel Cells[10]
- CO_2-EOR[11]
- "Easiest" geological CCS (for $30.10 per metric ton by 2050)
- "Mid-level" geological CCS (for $70.20 per metric ton by 2050)
- "Challenging" geological CCS (for $301.00 per metric ton by 2050)

- **GHG Offsets**
  - DAC[12]
  - Reforestation[13]
  - Restoring Soil Carbon[14]
  - Burying Biomass[15]

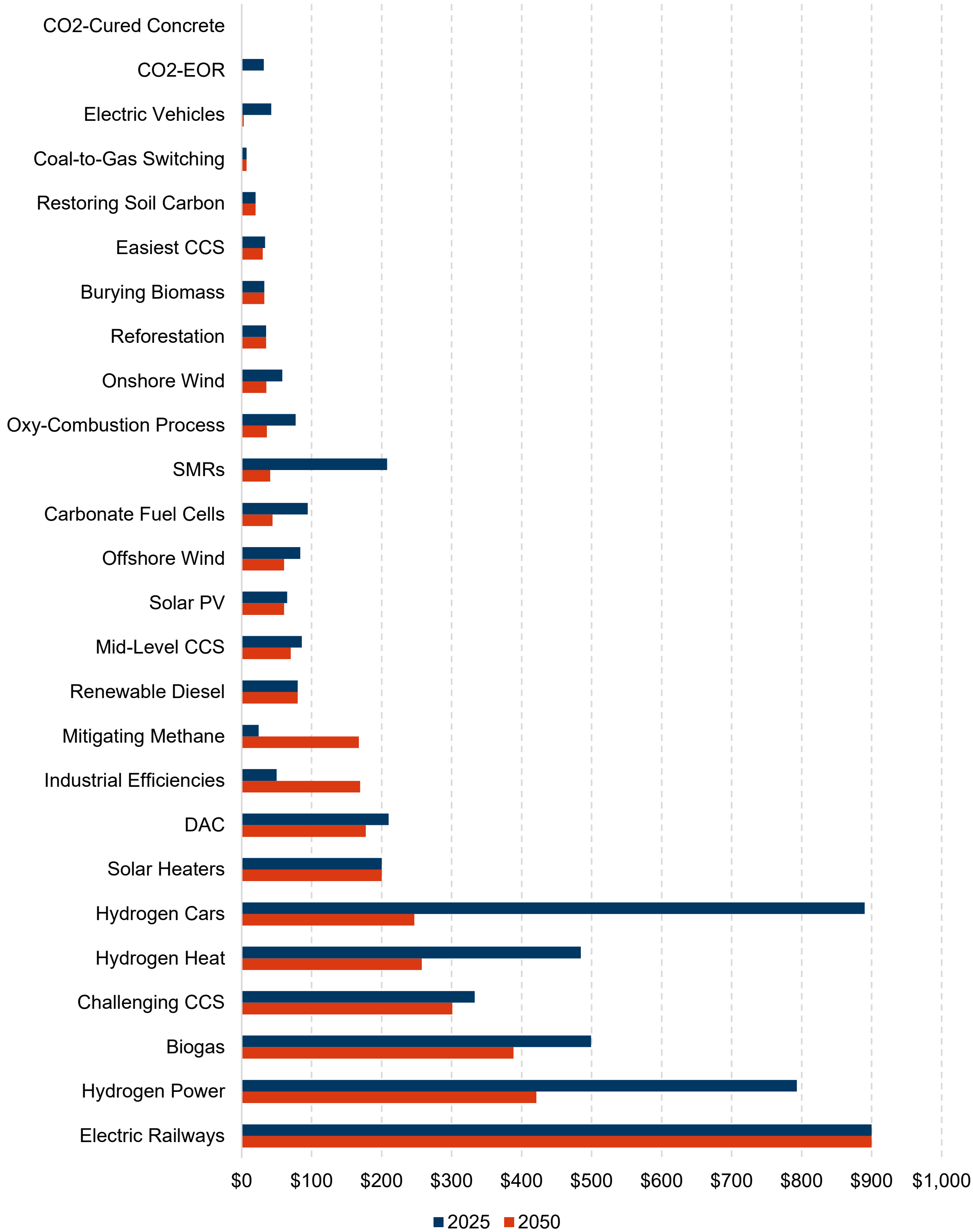
All these technologies would reduce net GHG emissions. Some of the options would convert direct fossil use into power demand (e.g., electric vehicles, "EVs," replacing ICEs). The ones within the power sector would reduce the average per MWh emissions rate from power plants (e.g., lower thermal dispatch because of higher renewable output, etc.). Others would replace fossil fuels with low- or zero-carbon alternatives (e.g., hydrogen-related technologies), and the remainder would reduce net emissions through CCS or offsets.

CERT is set up such that each technology has a "floor" and a "ceiling" for its level of possible deployment each year. Without a carbon fee, the technology would always remain on its floor – the minimum amount of deployment as specified by TSE data. The floor may be zero, especially for emerging technologies like SMRs or large-scale CCS deployment.

Under a carbon fee, the technologies may rise from their floor in terms of their projected level of deployment. At a high enough carbon fee, they hit their ceiling. Figure 1 shows data from TSE illustrating at which carbon fee amount the technologies become economical and rise from their floor. These economical prices change over time and are lower in 2050.

For existing technologies, the floors represent either the historical deployment levels or the deployment due to policies exogenous to carbon pricing. For instance, wind and solar capacity has been growing by gigawatts ("GW") per year because of strong economics for renewables on wholesale power markets, demand for Power Purchase Agreements[16] from institutional investors and industrial customers, state/regional renewable portfolio standards ("RPS"),[17] and federal tax credits for renewables.[18] TSE data generally projects the emerging technologies as having a floor of zero in future years.

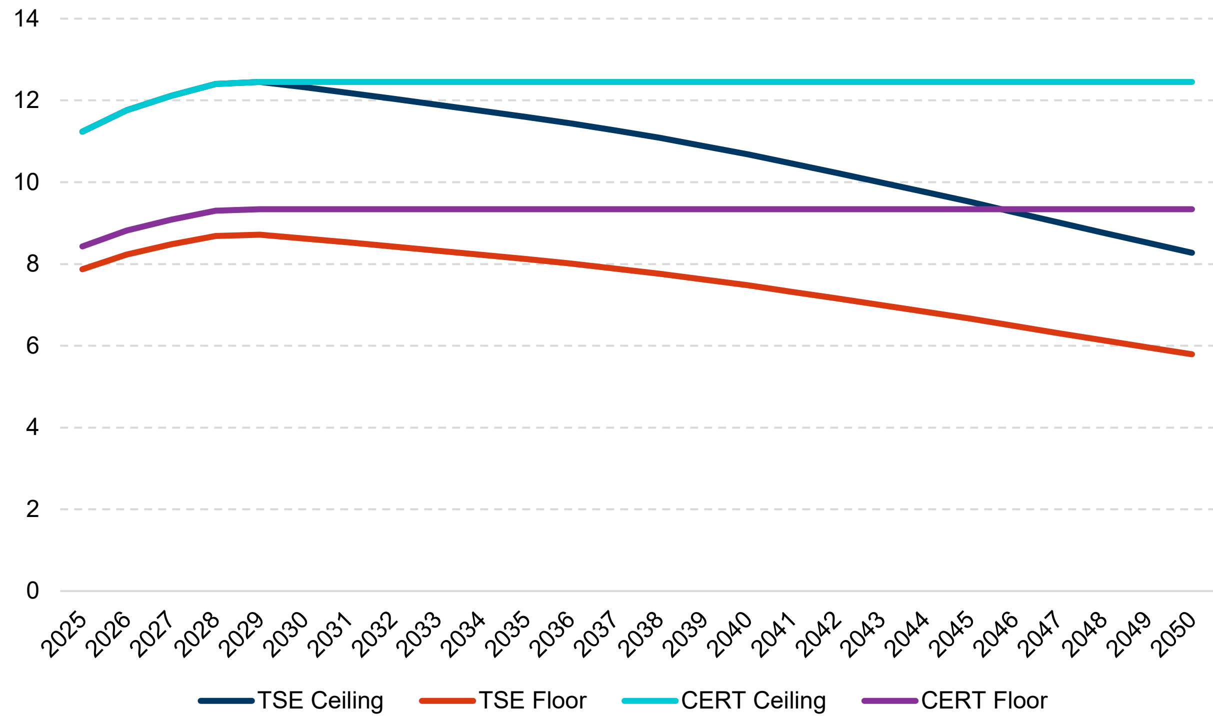
Figure 1 – Carbon price (in 2023 $ per ton of CO_2) from TSE where technologies lift from their floor



The ceilings for each technology represent real-world constraints on the possible rate of new deployment whether existing or emerging technologies. Examples of constraints include permitting, other regulatory issues, finite industrial capacity to produce the necessary capital equipment, and finite skilled labor to install and maintain the new infrastructure. To reuse wind and solar as an example, renewable builds cannot be infinite. Regional interconnection queues represent transmission constraints, industry can only produce so many PV cells and turbines per year, and only so many workers are available to install them.

Figure 2 shows the floor and ceiling for onshore wind deployment in the default TSE data as well as updated curves created by CLC. These lines are parameters in the CERT model and can be adjusted to evaluate different inputs for different scenarios.

Figure 2 – Maximum and minimum onshore wind additions (GW)



A major takeaway from the TSE data from Figure 1 and the CERT model is that each of the technologies has a finite amount of deployment available between now and 2050. Moreover, this implies that each technology has only a finite quantity of emissions reductions it can achieve. None of the technologies individually offer a substantial enough reduction to decarbonize the U.S. economy and U.S. energy sector in a realistic or comprehensive fashion. Hence, a suite of existing and emerging technologies utilized across all economic sectors would be necessary – exactly the outcome an instrument like a carbon fee is uniquely able to offer.

A discussion of hydrogen's place in Figure 1 is warranted. TSE projects hydrogen to be an expensive and inefficient technology to reduce GHG emissions:

> *"The absolute magic of renewables and electrification is their thermodynamics. These technologies can be 85-95% efficient end-to-end, precisely controlled, and ultra-powerful. […] However, the thermodynamics of hydrogen depart from the trend, converting high-quality electricity back into a fuel. The maximum theoretical efficiency of water electrolysis is 83% (entropy increases). Real-world electrolysers will be [approximately] 65% efficient. End-to-end hydrogen value chains will be 30-50%*

> *efficient. […] It therefore seems strange to take 100 MWh of usable, high-grade, low-carbon electricity and convert it into 40 MWh of hydrogen energy when you could have displaced 100 MWh of high-carbon electricity directly (e.g., from coal, etc.).”*[19]

Other forecasts are divided on hydrogen. The AEO, for instance, includes limited amounts of hydrogen deployment.[20] Still other forecasts, such as the BP energy outlook, see hydrogen as critical for decarbonization and meeting net-zero goals by 2050 as chemical feedstock, in the industrial sector, and in “heavy” air, rail, and water transportation.[21]

CERT does not include significant deviations from the outlook for hydrogen within the TSE data and summarized in Figure 1 and the quote before Footnote 19. Nonetheless, hydrogen could still play a significant role in the future U.S. energy system – such as “soaking up” what would otherwise be renewable curtailments to store energy as hydrogen fuel.

CERT Power Sector

The electric power sector in CERT deserves special elaboration. The diverse types of power generation (e.g., coal, gas, oil, hydro, nuclear, wind, solar, etc.) have complex interactions with one another on wholesale power markets. Additionally, electrification of some types of energy demand, such as ICEs being replaced by EVs, is a crucial aspect of modeling a technological pathway for decarbonization and would increase total system load.

CERT models the U.S. power sector in terms of capacity, generation, and emissions by each technology at the national level in the following manner:

- Growth in “underlying demand” – that is, demand from existing residential, commercial, and industrial customers before electrification induced by a carbon fee – is based on U.S. population growth and per capita power demand.
- “Underlying demand” includes the load associated with uses like air conditioning, lighting, heating, refrigeration, laundry machines, consumer electronics, and industrial equipment that currently makes up most U.S. power load.[22]
- Additional load is added to the system based on the deployment of new technologies requiring electricity – especially EVs as well as residential and commercial heating through electric heat pumps.[23] CERT processes this electrification through reduced demand for direct fossil use (e.g., motor gasoline for vehicles, natural gas for home heating needs, etc.) and the emergence of an equivalent quantity of energy service provided by electricity adjusting for different loss rates.
- The electric power sector must service this new load associated with electrification through higher renewable output or increased thermal dispatch.
- Hydroelectric dams and the legacy[24] nuclear fleet dispatch based on their aggregate capacity and historical capacity factor (e.g., 89% for nuclear). CERT neither adds nor retires hydroelectric capacity. The legacy nuclear fleet remains operating through at least 2050 in the model under the assumption the plant owners file the necessary paperwork to extend their licenses to operate perpetually.
- SMRs may be added to the power sector under the conditions described in the CERT Overview and with a high enough carbon fee for Figure 1.

- Wind and solar plants dispatch based on installed capacity, projected capacity factor systemwide from the AEO for each technology,[25] and CERT estimating curtailment rates based on renewable capacity as a share of total capacity.
- TSE uses historical curtailment rates from renewable-heavy regions (e.g., Southwest Power Pool, "SPP,"[26] in the U.S., which has high wind penetration rates, etc.) worldwide to estimate a relationship between renewable penetration rates and curtailment rates expecting more and more renewables creates the supply, demand, and transmission conditions leading to the curtailment of renewable resources.
- CERT projects a baseline level of wind and solar builds based on TSE data and AEO forecasts without a carbon fee. With a carbon fee, the level of wind and solar builds increases because of higher power demand from electrification and higher prices on wholesale markets where coal and natural gas set the price. The higher price would make a higher level of wind and solar installations more economical and attractive to electric utilities, various investors, and individual homeowners.
- Without a carbon fee, CERT projects coal generation and capacity to follow projects for the same from the AEO outlook. This assumption reduces the size of the 200 GW coal fleet down to around 70 GW of capacity by 2050. Generation decreases from around 800 terawatt-hours ("TWh") per year now to 275 TWh per year.
- With a carbon fee, coal retirements occur at a rate dictated by the spark spread bias[27] between coal and natural gas prices including the carbon fee. Coal capacity and coal generation always change in equal proportion to each other.
- Petroleum plants dispatch at historical capacity factors and retire 5% of capacity each year – a depreciation rate unaffected by the carbon fee.
- Natural gas plants are the "swing producer" tasked with making up any difference between power demand and supply. Projected generation by hydro, nuclear, SMRs, wind, solar, coal, and DFO is subtracted from total load. Within CERT, gas generation then equals this amount. This construction is a realistic representation of the role gas plays in the market throughout the U.S. as the technology responsible for respond to fluctuations in supply and demand keeping the system balanced.
- In CERT, the capacity of the gas fleet can either expand or contract based on the fleet capacity factor. Because gas is the swing producer, any decrease in electricity supply (e.g., coal retirements or cloudy and windless days, etc.) or increase in power demand (e.g., rapid population growth or a hot day leading to high demand for air conditioners, etc.) not made up for by additional nuclear, wind, or solar generation must be made up through increasing output and the capacity factor of gas plants.
- CERT uses the gas fleet's capacity factor to model additions and retirements:
    - If the fleetwide capacity factor is high enough, then capacity expands. Such conditions could arise because of high load growth from population growth, an increase in per capita electricity demand, or electrification. Supply-side factors contributing to high gas capacity factors would include coal retirements, modest renewable builds, or low renewable capacity factors.
    - If the fleetwide capacity factor is low enough, such as because of meager load growth and a rapid increase in SMR, wind, and solar output, less gas capacity is required on the market, and a small amount retires in CERT.

- Neither additions nor retirements take place when the fleetwide capacity factor is at a moderate level consistent with historical stability.
- CERT does not distinguish between less efficient (as measured by the heat rate quantifying the conversion rate between fossil inputs in MMBtu and output in MWh) combustion turbines ("CT")[28] from more efficient but more expensive combined cycle ("CC") units.[29] Thus, CERT models the gas fleet maintaining something close to its present mixture of these units with CTs active mostly at peak load and CCs dispatching more regularly.

- Net power imports are not modeled by CERT. In 2022, net electricity imports to the U.S. were 0.140 quadrillion BTUs ("Quads") while U.S. generation was 37.7 Quads.[30] Hence, net imports make up 0.37% of U.S. generation. While important in certain regions like New England, imports are not modeled in this iteration of CERT.

CERT Model Documentation

This section details the changes made by CLC to the default TSE data for CERT and the structural additions made to create new linkages in CERT. Examples of the new linkages include adding electric heat pumps to replace demand for natural gas from residential and commercial customers as an electrification option and a more detailed representation of the relationship between renewable curtailments and storage. These changes in the electricity sector further affect renewable economics and thermal dispatch.

To provide context and substance to the examples in the CERT documentation, a modeling scenario has been prepared representing the pillars of the Carbon Dividends Plan advanced by CLC.[31] For the purposes of CERT, this includes an economywide carbon fee beginning at $40 per metric ton of CO_2 in 2025 in 2017 dollars and increasing each year by 5% more than the rate of inflation. In 2023 dollars, this is $50 per metric ton of CO_2.[32] In 2023 dollars, the carbon fee eventually reaches $169.32 per metric ton of CO_2 in 2050.

This section is organized around the different sectors of the U.S. economy on the demand side and different sectors of the U.S. energy sector on the supply side.

Macroeconomics and Demographics

- CERT uses the population and real GDP forecasts from the AEO[33] to project growth in demand for energy services. Between 2025 and 2050, the AEO projects U.S. population to grow from 338 million to 372 million (a growth rate of 0.4% per year). Between 2025 and 2050, the AEO projects real GDP to increase from $20.4 trillion (in 2012 dollars) to $33.4 trillion (a growth rate of 2.5% per year in real terms).
- CERT includes a parameter adjusting the level of energy efficiency adoption in the baseline scenario without a carbon fee. For this scenario, this has been set at -1.6% "baseline (true) efficiency change" per year – twice the historical average of -0.8% per year from TSE estimated from the IAE efficiency report.[34]

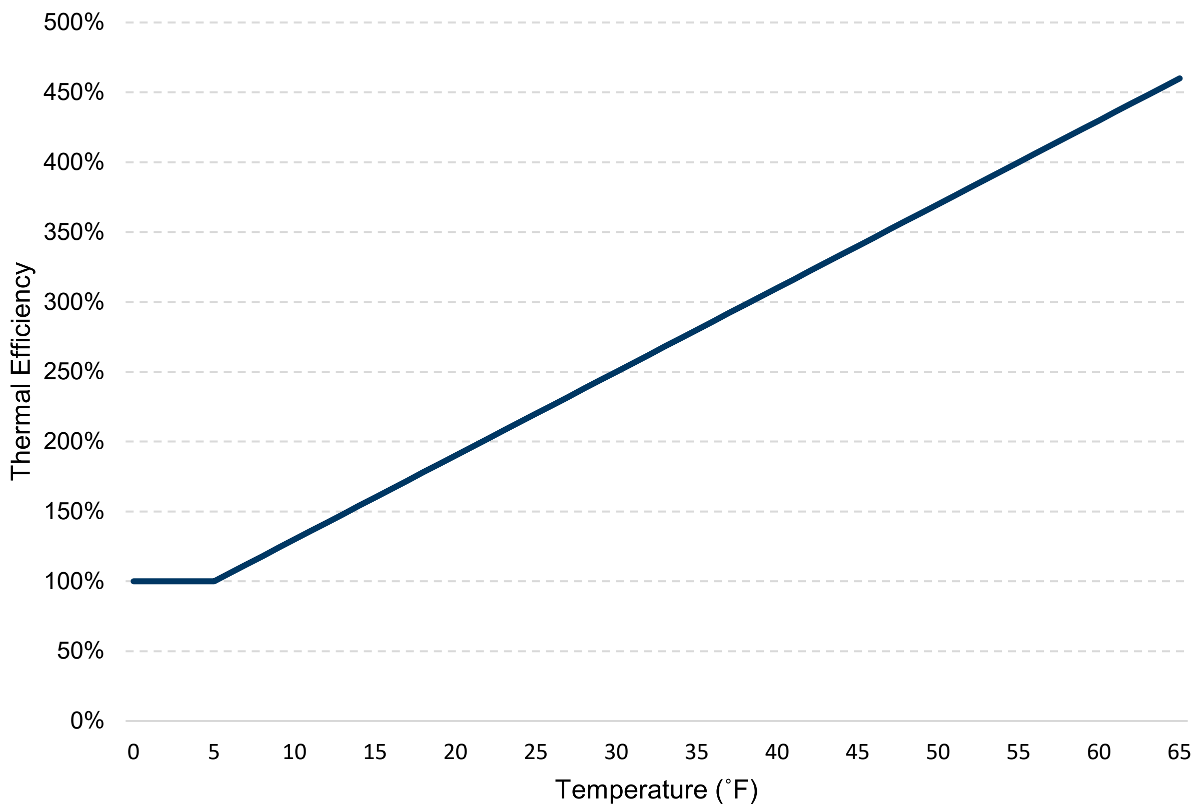
Residential and Commercial Sectors

- CERT introduces heat pumps as an option to electrify gas use and replace it with power generation for residential and commercial customers. This could reduce GHG emissions if marginal generation has a low emissions rate per new MWh.

- This electrification capability has been extended to residential and commercial use of petroleum fuels for heating – but turned off in this scenario.
- According to the AEO, residential and commercial customers would have purchased 0.907 Quads of petroleum fuels for direct use.[35] These fuels include propane, DFO, motor gasoline, kerosene, and residual fuel oil for heating.
- Homes and commercial buildings relying on such fuels for heating typically have a robust reason for doing so. Many of them are located in isolated communities (e.g., Alaskan villages, etc.) or have poor access to natural gas utilities (e.g., many rural communities throughout the U.S., etc.). While CERT inputs can be changed to allow carbon pricing to influence the decision to electrify direct petroleum use, this scenario leaves it "off" to reflect these real-world infrastructure constraints.
- The previous assumption mostly affects Alaska, New England, and other northerly states.
- Most residential (an estimated 5.186 Quads in the AEO for 2023)[36] and commercial (3.610 Quads) heating and cooking demand takes the form of natural gas. Because customers using natural gas by definition have access to a gas utility, they are nearly always going to have access to an electric utility, as well.
- CERT uses a different methodology for electric heat pumps than "floor and ceiling" from the CERT Overview and Figure 1. The approach involves to main sources, the Residential Consumer Energy Survey ("RECS")[37] and the Commercial Buildings Energy Consumption Survey ("CBECS").[38]:
    - RECS and CBECS detail residential and commercial consumption of fossil fuels for a small set of use cases (e.g., heating).
    - RECS and CBECS include data on consumption by fuel type. The fuel types include liquified petroleum gases ("LPG") like propane and butane, DFO, and natural gas. CLC aggregated use cases into three categories:
        - Space Heating
        - Water Heating
        - Other (mostly cooking)
    - Electrification would proceed differently for each of these categories. Space heating has the most intricate methodology to account for hourly temperatures and the seasonality of heating demand. Water heating and cooking are simpler because they operate indoors at normal room temperature.
    - A vital component of this analysis is determining the "thermal efficiency" when switching from direct fossil use to electricity in terms of the total energy inputs needed to provide equal energy service. Natural gas furnaces can only provide energy output equal to their energy input minus some small factor for heat loss. Electric heat pumps, on the other hand, can use available ambient energy within the air or the ground and require less input for the same energy output when compared to the combustion of fossil fuels in a furnace.
    - For space heating, the thermal efficiency of the conversion depends on outside temperature. For water heating and cooking, the thermal efficiency is more predictable because these use cases mostly occur indoors.

- Electric heat pumps are more efficient at higher temperatures when a higher degree of energy is available from the air and ground. When the temperature decreases, heat pumps become less efficient. Figure 3 shows the "efficiency curve" used in CERT from the American Gas Association.[39]

Figure 3 – Thermal efficiency of electric heat pumps



- For instance, according to Figure 3, at 50˚F heat pumps deliver 370% energy output compared to 100% energy inputs. Reversing these two figures implies electric heat pumps need 27%[40] of the energy needed by a hypothetical fossil furnace with perfect efficiency for the same energy service.
- According to the American Gas Association, new natural gas-fired furnaces in good working order are approximately 97% efficient.
- Therefore, if the demand for energy service is 1,000 Btus, then the gas furnace would require 1,031[41] Btus of gas inputs. The electric heat pump would require 270 Btus[42] of power inputs to provide the energy service. These results imply heat pumps only need 26% of the thermal input of gas.
- Efficiency changes as temperatures fluctuate. These ratios do not account for the losses associated with power generation and transmission.
- Based on the efficiency curve in Figure 3, CERT models electrification of water heating at 21.1%[43] thermal inputs compared to fossil fuels.
- For cooking purposes, the thermal efficiency of the conversion is assumed to be 42.2%.[44] This input assumption is less critical because cooking/other use cases are relatively minor compared to space and water heating. To quote the source

of this figure, “As you can imagine, it is far more efficient to heat directly instead of indirectly. Induction is able to deliver roughly 80% to 90% of its energy to the food in the pan. Compare that to gas, which converts a mere 38% of its energy, and electric, which can only manage roughly 70%.”[45]

- While these are parameters in CERT that can be changed, the current scenario for carbon pricing converts 100% of water heating and 50% of cooking demand to electricity starting in 2025 and finishing in 2044. This increment represents a 20-year lifecycle for the equipment (stoves, ovens, etc.).
- When old equipment depreciates and needs replacement, the new equipment replacing it would use electric power as its energy input. This scenario presumes no equipment in a good state of repair is replaced before the natural end of its expected lifecycle which, again, is assumed as 20 years.
- Modeling the share of gas demand for space heating undergoing electrification and its thermal efficiency is more nuanced and regionalized. These calculations require an hourly temperature shape for each U.S. state.
- The state-level temperature shape has three purposes:
  - CERT models residential and commercial structures adopting a “hybrid” system for space heating. The hybrid system would dispatch heat pumps for higher temperatures when heat pumps are most efficient. The hybrid system would dispatch gas furnaces for lower temperatures when heat pumps are less efficient and generally less effective.

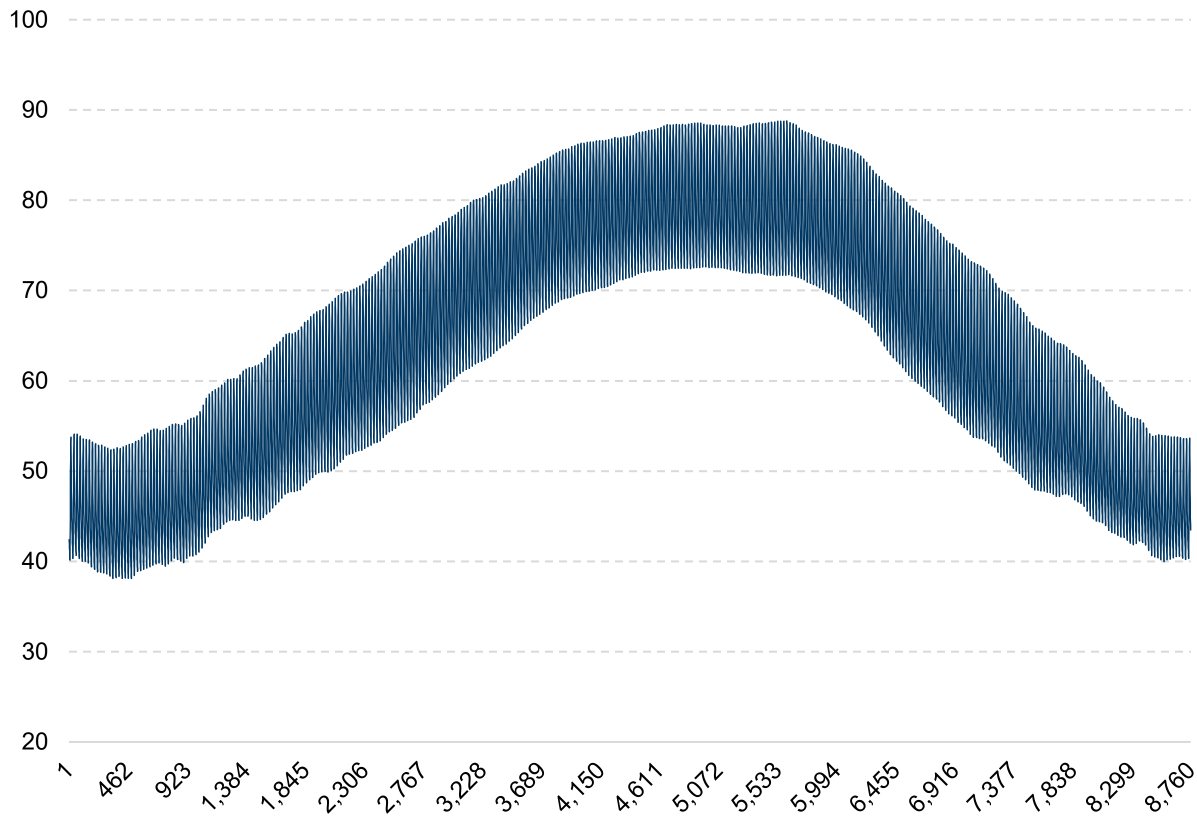
    The hybrid system is intended to model the behavior of a representative residential or commercial structure. In reality, some structures might only utilize heat pumps while others might stick with natural gas no matter the price of carbon. These situations are assumed to be offsetting, meaning the hybrid system represents the median structure.

    The hourly shape is helpful in determining during which hours heating demand would be electrified (ones with higher temperatures when heat pumps are at their most efficient) and which hours when gas furnaces would be dispatched (ones with lower temperatures).

    Because different states have different temperature shapes, their level of electrification would be different.
  - Outside temperature determines the efficiency of heat pumps by the hour.
  - Outside temperature determines the share of space heating demand for every hour of the year based on each hour’s share of heating degree days (“HDD”).[46] For example, if the temperature in Alabama the first hour of the year is 42˚F, then that hour has 0.94 HDD.[47]
  - In the dataset used for CERT, Alabama has 2,415 aggregate HDDs throughout the year. Dividing 0.94 HDDs in an hour by 2,415 HDDs for the year leaves that hour with 0.039% of annual load.
- An hourly temperature shape by state[48] was derived for the CERT modeling with data from the Climate Data Online Search[49] provided by the National Centers for Environmental Information.[50] The “raw” data is provided for the database by the National Oceanic and Atmospheric Administration (“NOAA”).[51]

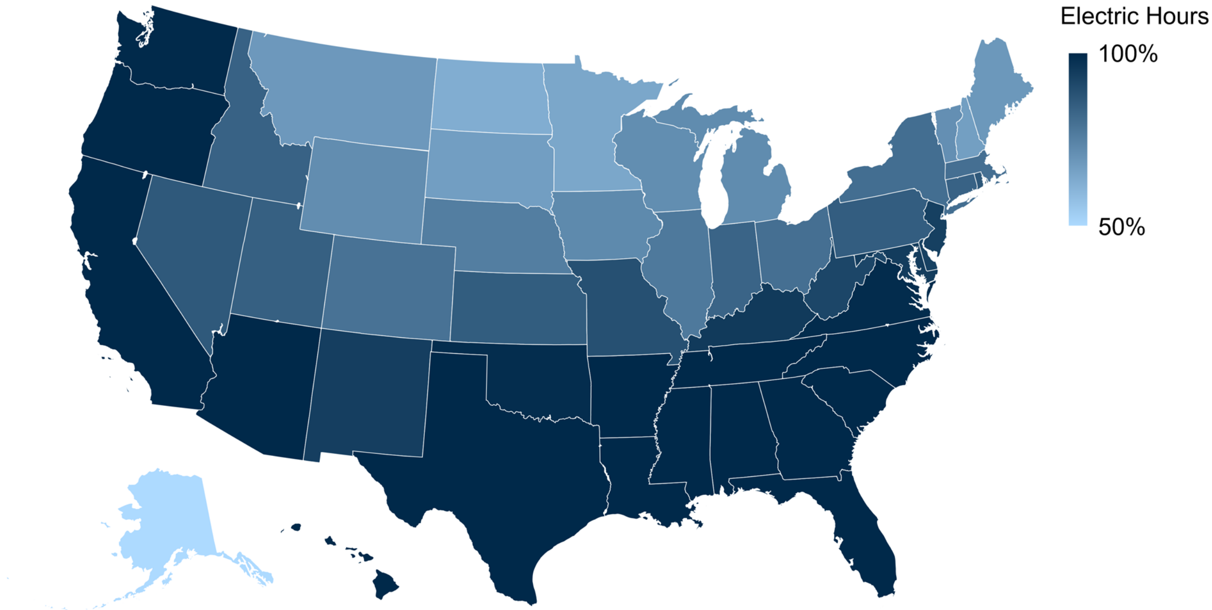
- The data includes HDDs and cooling degree days (“CDD”) by the hour for weather stations throughout each state (usually at airports and military installations). All weather stations were used for all states at equal weight.
- To transform the HDDs and the CDDs into temperature, HDDs by hour were subtracted from 65˚F and CDDs by hour were added to 65˚F. The resulting pair of temperature estimates was then averaged into one. Figure 4 shows example outputs of this process with Alabama’s temperature shape.

Figure 4 – Hourly temperature shape for Alabama based on NOAA data (˚F)



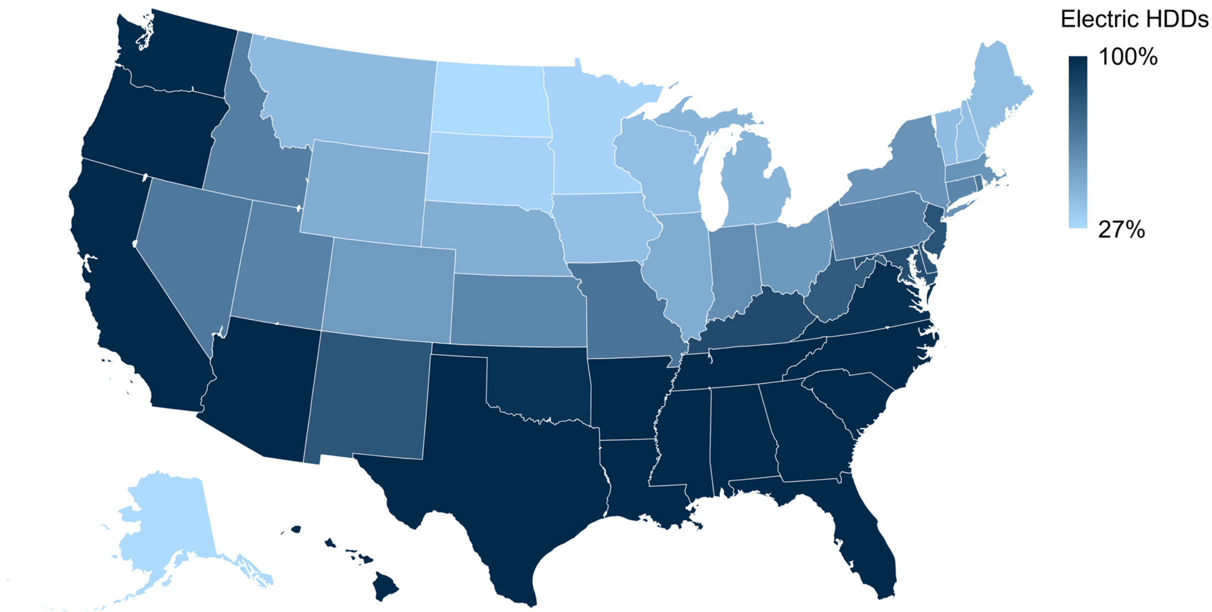
- Each hour for each state was assigned to be either an “electric hour” or a “fossil hour” based on the temperature. An “electric hour” has a temperature above 32˚F while a “fossil hour” is equal to or below 32˚F.
- Figure 5 shows the share of the hours assigned as an electric hour by state. According to the CERT methodology, most southern and western states would electrify 100% of residential and commercial space heating by 2044 using the same 20-year lifecycle input as water heating and cooking.
- The states with fewer than 100% of their hours tagged as an electric hour are modeled as hybridizing space heating to various degrees. Colder and northerly states, such as Alaska, North Dakota, and the states in northern New England, would have limited conversion to heat pumps and retain gas furnaces for their coldest temperatures. The states in the middle of the country by latitude— such as those on the Ohio River, in the southern Great Plains, and in the Mountain West—are modeled having intermediate results.

Figure 5 – Share of hours assigned as electric hours by state (%)



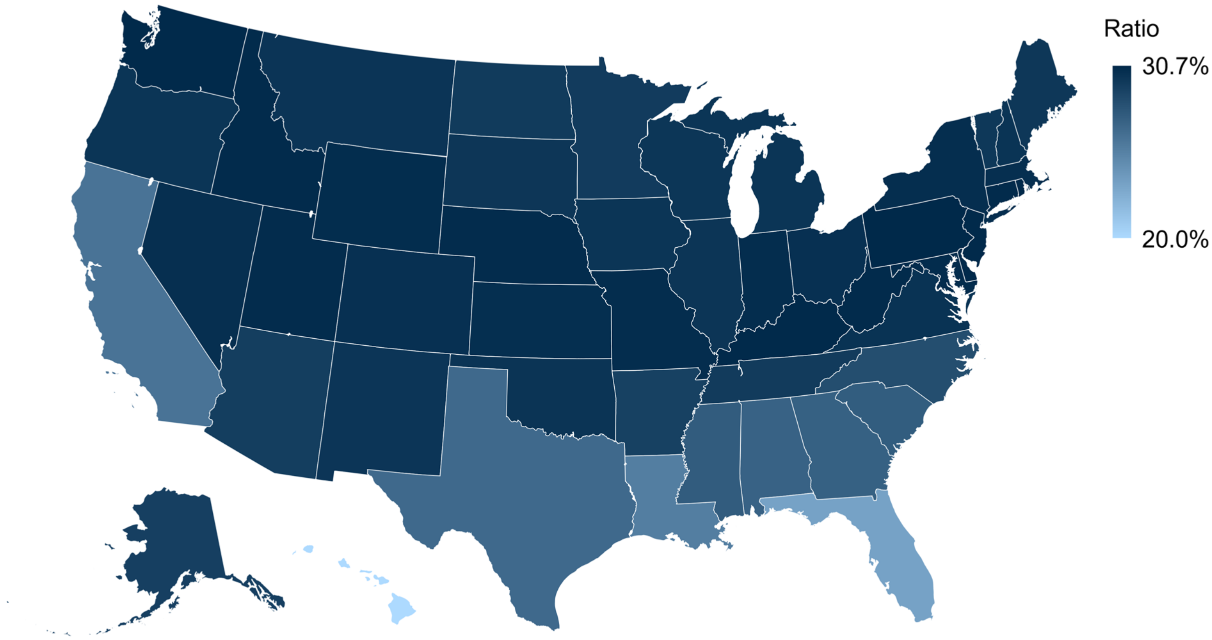
- Figure 5 implicitly weighs all hours of the year equally. However, in reality heating demand fluctuates by season and hour based on the outside temperature at the time by state, making it instructive but only a partial step.
- Figure 6 adjusts the data underlying Figure 5 to account for this phenomenon, weighing the hours by their share of annual HHD, such as the example discussed with 0.039% of annual load in one hour in Alabama.
- For instance, North Dakota has 62% of its hours above freezing (and therefore tagged as electric hours and running on heat pumps) but only 27% of its HDDs occur during hours above freezing. The remaining 73% of its HDDs (ones tagged as fossil hours and running on gas) occur in hours at or below freezing. This combination models a limited amount of electrification for North Dakota in CERT, an amount that increases the further Figure 6 radiates away from North Dakota throughout the West, Midwest, and Northeast regions.

Figure 6 – Share of HDDs assigned to electric hours by state (%)



- The next step in the CERT modeling process involved determining the average thermal efficiency of the conversion for electric hours. This calculation is the weighted average of the conversion efficiencies from Figure 3 adjusting for the 97% assumed efficiency of gas furnaces using the share of HDDs by hour for only the electric hours from Figure 5 and Figure 6.
- llustrating the final result of these steps, Figure 7 shows the thermal efficiency of electricity relative to natural gas to replace the energy service in hours tagged as electric hours. For instance, the 26.2% for California indicates the state's heat pumps on average need 26.2% the power as an input when compared to the gas needed for a natural gas-fired furnace. Figure 7 also shows equivalencies to provide the same level of energy service.
- As expected, the conversion to heat pumps would be most efficient in the warmer southern and western states. Examples include Hawaii, California, Texas, and Florida. The conversion is less efficient in colder states where temperatures in the winter and "shoulder months"[52] are between 32˚F and 50˚F.
- States falling into this "moderately cold" category where heat pumps would then dispatch most of the required hours each year, unlike the coldest states, include Pennsylvania, Delaware, New Jersey, Washington, Kentucky, Rhode Island, Connecticut, Maryland, West Virginia, and Idaho.

Figure 7 – Thermal efficiency of conversion (MMBtu power / MMBtu natural gas)



- Many of the coldest states (e.g., Alaska, Minnesota, North Dakota, etc.) in the winter have the most extreme swings in temperature between midsummer and midwinter. These states show a slightly higher thermal efficiency of conversion compared to, for instance, Mid-Atlantic states because the heat pumps in the coldest states would not operate during the coldest hours and have few hours with outside temperatures between 32˚F and 50˚F.

Industrial Sector

- CERT adapted numerous sources of data to differentiate between several energy, technology, and types of fuel uses in the industrial sector.
- The default data from TSE was reorganized to differentiate between petroleum used as feedstock and petroleum used as fuel. Feedstock uses include, "Chemical feedstocks derived from refined or partially refined petroleum fraction, principally for us in the manufacturing of chemicals, synthetic rubber, and a variety of plastics."[53]
- CERT removes a correlation in the default TSE data between coal consumption by the industrial sector and geological CCS. The default data included this linkage under the assumption more CCS would allow for more "room" for industrial consumption of coal (and ensuing emissions) while still reducing net GHG emissions.
- While this effect could take place, there is not a strong market or policy link between these factors in energy markets or with a carbon fee, respectively. Without such a link, the correlation between these sectors has been removed in CERT.
- CERT includes hydrogen as a technological pathway to help decarbonize industrial activities. However, under the Baker-Shultz plan, the carbon fee would not reach the levels needed to activate hydrogen; Figure 1 demonstrates that carbon prices would need to exceed $425 per ton to support hydrogen deployment.

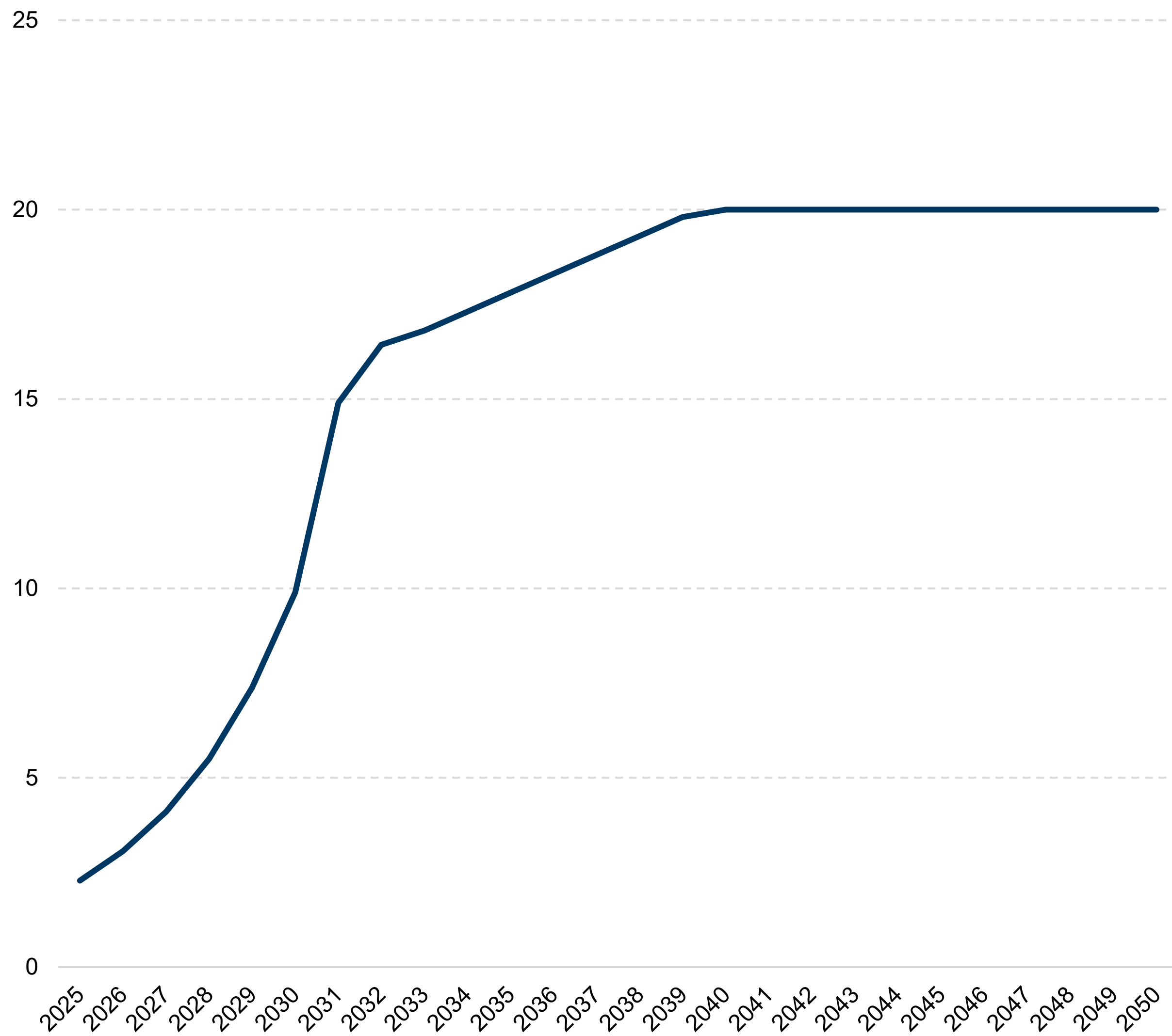
Transportation Sector

- Different outlooks can vary wildly on their expectations for the level of electrification with light-duty vehicles ("LDV") between the 2020s and 2050:
    - The AEO Reference Case for vintage 2022 expected 20.2 million LDV EVs on U.S. roads by 2050.[54] Vintage 2023 increased this forecast to 36.3 million LDV EVs on U.S. roads by 2050.[55]
        - This increase of 16.1 million is likely because of the provisions of the Inflation Reduction Act related to EVs and charging capacity.[56]
        - While 20.2 million to 36.3 million is a significant increase, the 2023 AEO forecast only anticipates 12% of the LDV fleet would be electrified by 2050 absent additional policy or changes in the market.
    - The TSE outlook for the U.S. LDV fleet anticipates the economics of EVs will be so attractive virtually the entire fleet would electrify by 2050 – even without any additional policy interventions or a Baker-Shultz carbon price.[57]
    - Another influential projection is produced by Bloomberg New Energy Finance ("BNEF") and its "Electric Vehicle Outlook 2023."[58] The BNEF projections are more optimistic than the AEO projections but more conservative than the default TSE outlook. BNEF projects approximately 40% of the fleet (stock) and 60% of new sales (flow) for LDVs to be electric by 2050.
- CERT can use different outlooks based on analyst preferences. For Baker-Shultz, the BNEF forecast underlies the baseline scenario for U.S. energy markets because BNEF is a respected market intelligence firm in this area of analysis.
- CERT reserves 4.5 million LDVs as ICEs by 2050. This reserve, which is about 1.5% of the fleet, represents unusual cases like classic cars and high-performance sportscars less subject to the economics underlying a carbon fee.
- CERT uses the projections from the AEO on vehicle miles traveled ("VMT") per EV and the MWh of load associated with each VMT when charging.
- For instance, in 2050 and based on the AEO data, CERT models each LDV EV as traveling 12,429 miles per year and requiring 0.446 kilowatt-hours ("KWh") per VMT (including 7% transmission and distribution losses) of charging.[59]
- CERT electrifies commercial light trucks at the same rate as LDVs.
- CERT electrifies light medium and medium-duty vehicles ("MDV") at half the rate of LDVs and commercial light trucks. This assumption is a reflection of the potential for electrification with MDVs – especially fleet vehicles and "last mile" delivery vehicles generally operating during normal business hours (and thus able to recharge their batteries overnight) and remaining in the same urban area.
- CERT includes LDV and MDV electrification load in its power sector. The parameters for MDV electrification were also taken from the AEO projections.
- Heavy-duty vehicles ("HDV") are modeled as unresponsive to the carbon fee in terms of what share of new purchases would be EVs in future years.
- HDVs mostly consist of construction vehicles like mobile cranes, cement mixers, refuse trucks, and tractors to pull container trailers.[60] These heavier vehicles would start to run

into similar energy-to-weight issues with batteries as those experienced by aircraft and ships; therefore, HDV electrification is not tied to a carbon fee.

- Hydrogen is an option for vehicles of any weight class in CERT. However, under the carbon fee proposed by Baker-Shultz, hydrogen vehicles are not competitive with the other alternatives based on the economic data in Figure 1.
- The number of LDV EVs added to the fleet each year depends on the same floor and ceiling methodology discussed in Figure 2 for the example of onshore wind. Figure 8 shows the floor (zero) and ceiling (the line) for LDV EVs in CERT.

Figure 8 – U.S. capacity to adopt LDV EVs (millions)



- CERT assumes a 15-year lifespan for new EVs consistent with the AEO.
- The timing of the Baker-Shultz carbon fee, the shape of the line from Figure 8, and the 15-year lifespan for EVs would combine to mean most of the LDV fleet would be EVs by the mid-2040s. The mid-2040s are a 15-year “lag” from the increased potential for the adoption of EVs spiking in the late 2020s and early 2030s.

Power Capacity and Generation

- Underlying demand by sector (residential, commercial, and industrial sectors) in CERT has been calibrated to the load projections in the AEO forecast. This calibration means load growth of around 0.5% per year between now and 2050.
- A carbon fee has some potential to induce energy efficiency and therefore temper the anticipated level of load growth.[61] Thus, for Baker-Shultz, CERT has been set up such that underlying demand grows at 0.33% per year out to 2050.
- CERT bases the trajectory of the coal fleet without a carbon fee on the AEO forecast. Approximately 100 GW of coal capacity has retired since 2011[62] because of competition with gas plants on wholesale markets, coal retirements mandated by governors and legislatures, and plants reaching the end of their lifecycles.[63]
- According to the AEO, the coal fleet will continue to shrink the remainder of the 2020s before retirements slow and installed capacity decreases at a slower rate. According to the EIA, 23% of the 200 GW of installed coal capacity has reported plans to retire by the end of 2029.[64] By 2050, the AEO projects 71 GW of coal remains.
- CERT models both additional and accelerated coal retirements under Baker-Shultz. According to Figure 1, replacing coal with gas on wholesale markets is one of the most economical ways to reduce emissions. Switching from coal to gas would happen at large magnitudes and quickly compared to the emerging decarbonization technologies with higher enabling carbon fees required listed in Figure 1.
- CERT either increases, maintains at a constant level, or reduces gas capacity based on the overall capacity factor of the gas fleet. Each year, CERT examines capacity factors and has four options for how to modify gas-fired capacity:
    - **Rapid Builds** – "Rapid Builds" represent conditions on wholesale markets such that gas plants are being dispatched with frequency and closer to their installed capacity (e.g., 50%+ capacity factors in the 2020s and 40%+ capacity factors in later years). These conditions would come about through some mixture of rapid load growth, rapid coal retirements, and limited renewable output (e.g., if wind and solar builds are backloaded closer to 2050).

      These factors in concert would likely increase prices and improve the economics of gas plants for investors and utilities. They would also indicate a power system with a need for more dispatchable resources to maintain its reserve margins. Both effects would support building more gas plants.
    - **Modest Builds** – "Modest Builds" are similar to Rapid Builds though with reduced extremity in the underlying factors supporting new gas builds (e.g., higher load, etc.) and therefore a proportionally smaller build response.
    - **No Change** – "No Change" indicates a fleetwide capacity factor such that the gas capacity is likely to remain unchanged. This situation would not completely preclude "churn" within the gas fleet when older, less efficient units are either retired/replaced by new plants or given new turbines.
    - **Retirements** – If the fleetwide capacity factor is lower than 30%, then 3% of the gas fleet would retire the next year. This situation could arise if the factors from Rapid Builds are inverted: meager load growth, the retention of the coal fleet, rapidly increasing renewable output, and increasing output from one of the emerging technologies from Figure 1 like SMRs.

Retiring no more than 3% of the gas fleet per year is a cautionary backstop in CERT's methodology. The gradual retirement of the gas fleet helps to maintain adequate reserve margins while other power types are brought online even if gas plants are only dispatched in response to peak load. A significant "legacy" gas fleet in future decades with diminished capacity factors would still be a relatively low-cost way for planners to maintain reserve margins.

- Figure 9 summarizes the capacity factors at which these different responses can occur and the change in the capacity of the gas fleet condition.
- Figure 9 shows two "eras" for the parameters: 2023 to 2029 and 2030 and 2050. CERT smooths the transition between them during the late 2020s.

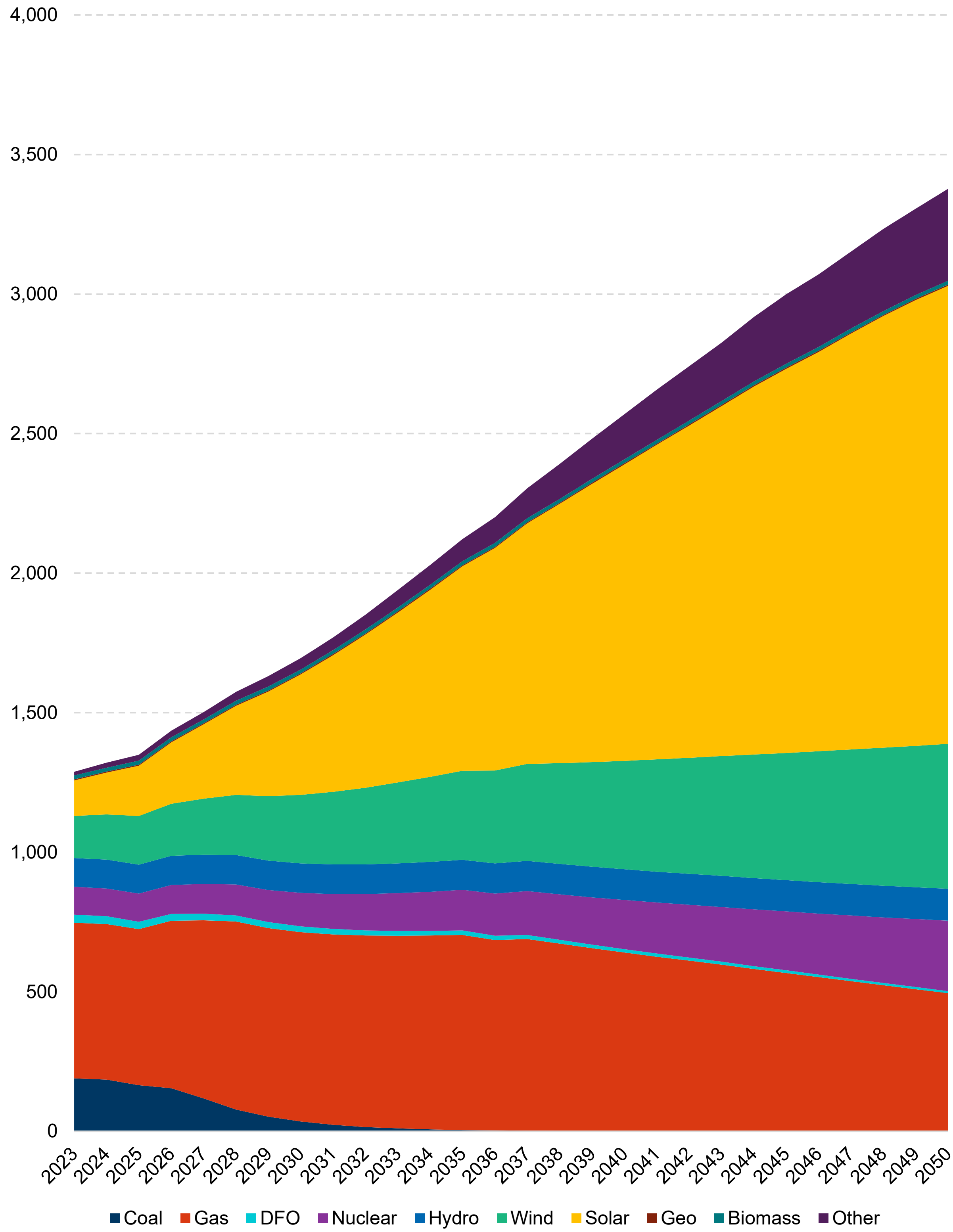
Figure 9 – Capacity factors associated with gas additions and retirements (%)

	2023 through ~2029		~2030 through 2050	
	Threshold	**Change**	**Threshold**	**Change**
Rapid Builds	>50%	+20%	>40%	+10%
Modest Builds	40% to 50%	+10%	35% to 40%	+3%
No Change	30% to 40%	0%	30% to 35%	0%
Retirements	<30%	-3%	<30%	-3%

- CERT assumes 5% of the DFO fleet retires each year. The rate of DFO retirements has no relationship with the carbon fee or any other model inputs.
- CERT models the efficiency[65] of thermal plants (coal, gas, and DFO) based on data[66] from the AEO. In 2023, coal plants are 32.6% efficient; by 2050, coal plants are 33.4% efficient. In 2023, gas plants are 44.0% efficient; by 2050, gas plants are 44.5% efficient. In 2023; DFO plants are 32.1% and by 2050 are 31.9% efficient.
- Like AEO, CERT projects that the thermal efficiency of fossil plants will change. For the coal and gas fleets, their efficiency is expected to improve slightly based on the AEO data. This increase would reflect older, less efficient plants retiring because they must purchase more fuel to generate the same amount of power as newer plants with newer equipment. The surviving plants are likely to be the most efficient.
- The historical capacity factor of the legacy nuclear fleet (roughly 90%)[67] is reused in CERT for incremental nuclear additions in the form of SMRs.
- CERT sources the capacity factor of wind and solar in the equivalent parameters from the AEO outlook.[68] Between 2023 and 2050, wind achieves its maximum capacity factor of 38% and solar of 24% with both being in the mid-2030s.

- Wind, solar, and nuclear SMR capacity can increase under Baker-Shultz based on the carbon fee and technology economics (summarized in Figure 1) and the floor and the ceiling methodology (with an example for onshore wind summarized with Figure 2, though similar constraints exist for each of the technologies).
- Without Baker-Shultz, CERT mirrors the projected installed capacity of battery storage from the AEO.[69] By 2050, AEO expects 163.5 GW of storage capacity. This level is a mixture of projected system economics and regional policy, such as states beginning to fold storage requirements into their RPS regulations.[70]
- A carbon fee would encourage further investments in battery storage. This effect was not originally present in the TSE data and has been added for CERT. The effect of a carbon fee on wholesale power markets would support more storage:
    - A carbon fee would increase load through electrification. Higher load creates opportunities for increased revenues and a higher need for firm capacity to help ensure the system can maintain adequate reserves.
    - A carbon fee would increase costs for thermal plants – decreasing their level of competitiveness on wholesale markets and increasing the price per MWh paid to other generating technologies for their power output.
    - More demand and higher prices improve the economics of wind and solar and therefore lead to higher renewable capacity and output.
    - A system with higher load and higher renewable generation would present more opportunities for the intertemporal arbitrage necessary for storage units to bring in revenues. An example would include a night with low demand but high wind output creating low or even negative prices that storage can "move" to the next day when prices are higher to sell the power at a profit.
- The exact degree of support a carbon fee lends to storage depends on the interactions between load growth, renewable output, thermal dispatch, and storage capacity (e.g., higher renewable output creates more opportunities for low-cost charging by batteries). The Battery Storage section has the details of these interactions.
- Figure 10 shows the projected capacity by technology for the U.S. power sector with Baker-Shultz from CERT. The current system with 1,300 GW of capacity is projected to increase to approximately 3,400 GW of capacity between now and 2050, mostly from additional renewable builds of wind and especially of solar.

Figure 10 – U.S. power capacity under Baker-Shultz (GW)



- Figure 10 shows one of the most critical results from CERT to share with policymakers and for diagnosing the effects of its methodology and approach on the power sector. Discussing each of the technology types is instructive:

- **Coal** – Under Baker-Shultz and according to Figure 1 and Footnote 8, the carbon fee induces coal-to-gas switching. CERT projects gas dispatch would replace coal dispatch by the late 2020s and early 2030s. The remaining coal would then be retired. Their sites could then be remediated, and their transmission hookups could then be reused for new resources (e.g., SMRs).
- **Gas** – Because of the coal-to-gas switching on power markets induced by the carbon fee in the late 2020s from Figure 1, gas-fired generation would increase, and the gas fleet would have higher capacity factors. Figure 9 indicates these higher capacity factors would lead to higher gas capacity.

  The new capacity would likely be high efficiency combined cycle ("CC") plants with new turbines and attractive heat rates.[71] New CC plants would be more competitive under a carbon fee compared to older coal plants and older gas plants with less proficient heat rates. While this effect is not estimated in CERT, there may be additional "churn" in the gas fleet when older plants would be cycled out and upgraded or replaced by new CC plants.

  After 2035, increasingly high renewable capacity (and generation) and the mass introduction of SMRs starts to put downward pressure on the fleetwide capacity factor for gas plants. Eventually the gas fleet starts slowly retiring – decreasing from 699 GW of capacity in 2035 to 495 GW in 2050. CERT only allows for the gradual retirement of the gas fleet to account for frictions in power markets for resource adequacy and necessary transmission upgrades.
- **DFO** – The DFO fleet is exogenous to the carbon fee in CERT. Therefore, the exogenous 5% retirement rate continues from now to 2050.
- **Nuclear** – CERT keeps the legacy nuclear fleet (of around 95 GW in capacity) operating on the market in perpetuity. Based on the economics of SMRs from Figure 1 and the carbon fee, commercial deployment of SMRs would begin in roughly 2035. By 2050, the nuclear fleet in Figure 10 would expand to around 250 GW including approximately 160 GW of new SMRs.

  Adding approximately 10.5 GW of SMRs to the U.S. power system each year[72] would signify rapid deployment, though it is consistent with other periods of rapid deployment of nuclear energy in U.S. and French history:

  - Most U.S. nuclear reactors became operational between 1965 and 1985.[73] During that period, roughly 5 GW came online each year. Thus, CERT and TSE data are projecting about twice the capacity coming online each year in the late 2030s and 2040s compared to the historical experience of the U.S. energy sector in the 1960s through the 1980s.

    This doubling becomes realistic when accounting for the nature of SMRs and the context of the grid. According to the International Atomic Energy Agency ("IAEA"), SMRs would be "physically a fraction of the size of a conventional nuclear power reactor" and then "it [would be] possible for systems and components to be factory-assembled and transported as a unit to a location for installation."[74] The mass retirement of the coal fleet (not occurring during the 1960s through the 1980s) from Figure 10 would create available transmission hookups for SMRs.
  - France is well-known for its nuclear-heavy power sector.[75] Like the U.S., France added most of its nuclear capacity over a 20-year period, this time

between 1975 and 1995.[76] France has 61.4 GW of capacity,[77] implying a build rate of 3.1 GW per year of nuclear capacity.

France accomplished this build rate with a much smaller economy behind it. French GDP was approximately 11% of U.S. GDP in 2022.[78] Therefore, scaling the historical rate of French deployment (3.1 GW per year) to the size of the U.S. economy gives an estimate of 28.2 GW per year, which is more than the approximately 10.5 GW per year rate in CERT.

- **Hydro** – Hydroelectric capacity continues at its historical levels.
- **Wind** and **Solar** – According to Figure 1, expanded wind and solar deployment would be economical under even a modest carbon fee. The rate of deployment would be determined by the floor and ceiling methodology from TSE data, which was summarized for onshore wind through Figure 2.

  According to Figure 10, by 2050 U.S. wind capacity would be 519 GW and U.S. solar capacity would be 1,641 GW. These expanded capacities represent a 3.4x and a 12.9x increase respectively from their current levels.

  The National Renewable Energy Laboratory ("NREL") estimates 10 MW of wind capacity can be built on a square mile of land.[79] NREL also estimates "3.4 acres of solar panels [generate] about a gigawatt-hour of electricity per year." Converting this to MW per square mile[80] to be comparable to the wind figure yields a result of 21.5 MW per square mile.

  For wind, the CERT output under the Baker-Shultz carbon fee implies 52,000 square miles would be needed for wind[81] and 76,500 square miles for solar.[82] The wind estimate is roughly the area of Arkansas; solar is roughly the area of South Dakota.[83] These estimates are consistent with other analyses of such land-use impacts of higher wind and solar capacity.[84]
- **Geothermal** and **Biomass** – Geothermal and biomass are exogenous in CERT, though they could be developed in future model updates.
- **Other** – The "Other" category in Figure 10 is primarily battery storage. Battery storage has an intricate set of interactions with load, wind and solar generation, renewable curtailments, and thermal dispatch. The methodology to address each of these interactions is summarized in the next section.

Battery Storage

- CERT integrates utility-scale battery storage as a technology encouraged by a carbon fee.[85] Like all emerging technologies, the economics of storage (e.g., their efficiency levels, lithium supply and demand, etc.) are uncertain. On the other hand, storage could have attractive features for the operators of the U.S. power grid:
  - Batteries help balance supply and demand throughout the day. They can be charged when power prices are low, zero, or negative when renewables would otherwise be curtailed and then discharged later.
  - An example of this phenomenon would include the "Duck Curve" on the CAISO market[86] and the emergence of similar supply and demand interactions on the wind-heavy markets in the Midwest (e.g., SPP, MISO).[87]
  - Batteries are dispatchable so long as they are charged. Hence, storage could contribute to maintaining adequate reserve margins.

    - Battery storage can improve system stability in other ways.[88]
- CERT includes batteries and creates linkages between storage capacity, wind and solar curtailments, renewable economics, and thermal dispatch:
    - First, CERT estimates the curtailment rate of renewables before availability of battery storage capacity.
    - Once pre-storage curtailments exceed 2% of pre-curtailment output,[89] then renewable curtailments can be used for charging.
    - In the baseline without the carbon fee, battery capacity is assumed to equal the AEO forecast of the same in CERT. AEO estimates the level of "diurnal storage" at 10.8 GW in 2023 and projects growth to 163.5 GW in 2050.[90]
    - Storage batteries need generation from another technology to charge up. The demand for "charging load" (separate from other types of batteries, especially in the transportation sector) is calculated by taking storage capacity and multiplying by the number of hours per year assuming four hours of discharge per day. A further 20% is added to account for battery inefficiencies.[91]
        - A one MW unit requires 4.8 MWh charging per day – one MW multiplied by four hours and 120% to account for battery inefficiency. Multiplying by 365 days per year equals 1,752 MWh of charging load.
    - Scaling this estimate up, the 163.5 GW of AEO capacity in 2050 would require 298 TWh of charging load. Ideally, most of this charging load would "save" power from being rejected in the form of renewable curtailments.
    - Renewables usually only curtail when power is priced at zero or negatively. These situations are alluring to storage because they can receive power for free or even be paid for it and then sell it later at a high price when system demand is high or wind and solar are limited by weather conditions.
    - CERT assumes "rescued" renewable curtailments can charge storage for 50 weeks per year once pre-storage curtailments reached 2% of pre-curtailment renewable output. The remaining two weeks represent the nadir of wind and/or solar output throughout a year. During those two weeks, the charging load would be addressed by an increase in natural gas dispatch.
    - The carbon fee would incentivize additional storage capacity through the inner workings of power markets and its effect on renewables:
        - Electrification (e.g., heat pumps, LDVs, MDVs, etc.) would increase the load. The higher demand would mean higher marginal dispatch costs for the thermal units "setting the price" in most hours.
        - Developers, investors, and utilities would seek to garner the increased level of producer surplus on the market for low- or zero-marginal cost resources by building more wind and solar capacity.
        - The combination of higher load and more renewable energy would help create more opportunities for intertemporal arbitrage where storage units make their money by buying low and selling high.
        - Storage further improves wind and solar economics. The prevention of curtailments – energy not demanded by the grid in an hour but available to charge a storage unit for later – with storage increases the effective

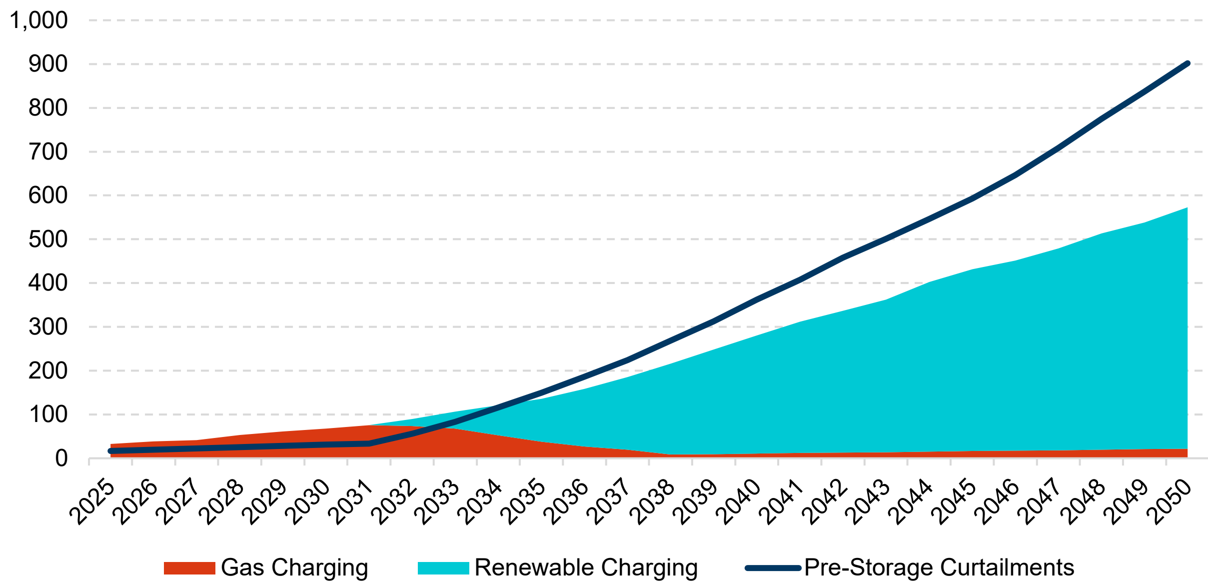
capacity factor of renewables. With a higher capacity factor, renewables sell more power into the market for more revenue.

    - CERT includes and balances all these economic interchanges.

  - CERT can make an economic decision to build more storage capacity when a high quantity of pre-storage curtailments is available.
  - New builds occur such that the post-storage curtailment rate of renewables from the baseline scenario remains the same with Baker-Shultz.
  - Simulating this effect out with the power sector forecasted in Figure 10 would lead to a rough doubling of the AEO's forecasted capacity. Instead of 163.5 GW, CERT models storage capacity as close to 320 GW by 2050 with the carbon fee and its influence on U.S. electricity supply and demand.

- Figure 11 shows these interactions playing themselves out with the carbon fee. CERT estimates pre-storage curtailments based on wind and solar capacity as a share of total capacity shown in Figure 10. By 2050, CERT estimates U.S. renewable capacity would be extensive enough to induce pre-storage curtailments of 902 TWh, which is around one-fifth the size of the total U.S. power market in 2023.

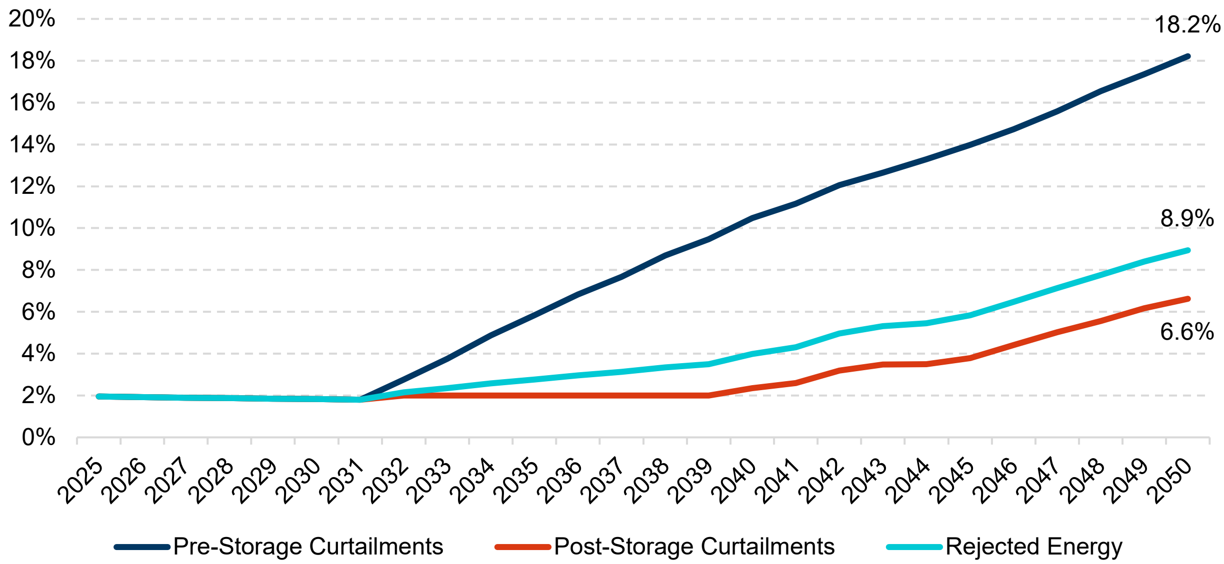
Figure 11 – Pre-storage curtailments and battery charging by category with Baker-Shultz (TWh)



- Charging load is the sum of "Gas Charging" and "Renewable Charging." The level of post-storage curtailments is equal to the difference between pre-storage curtailments (904 TWh in 2050) and Renewable Charging (574 TWh in 2050):
  - **Pre-Storage Curtailments** = 902 TWh
  - **Gas Charging** = 23 TWh
  - **Renewable Charging** = 574 TWh
  - **Charging Load** = 597 TWh (22 TWh plus 574 TWh)
  - **Post-Storage Curtailments** = 328 TWh (902 TWh minus 574 TWh)

- Under Baker-Shultz, the post-storage curtailments in 2050 would be 351 TWh. This quantity is approximately the total load for California and Washington in 2022. This energy could still be rescued by other means, such as forming the foundation of a hydrogen economy by utilizing the power for electrolysis.
- Figure 12 shows the pre-storage, post-storage, and rejected energy rates relative to the pre-curtailment generation by wind and solar plants:

Figure 12 – Curtailment rates for renewable power generation with Baker-Shultz (%)



- From 2025 to 2031, the estimated pre-storage curtailment rate would not exceed 2% of pre-curtailment generation. During these years, CERT models 100% of the charging load as addressed by gas dispatch (as seen within Figure 11).
- Starting in 2032, the CERT's pre-storage curtailment rate exceeds 2% and hence the renewable curtailments become available for charging load. This effect helps to hold the post-storage curtailment rate down at 2% through 2040. After 2040, the scale of U.S. renewable generation would begin to increase this share.
- The potential curtailments not rescued by charging are a form of energy loss. Sending pre-storage curtailments through a storage unit can rescue some of this energy loss, though there will always be inefficiencies when using batteries.

Load Accounting

- CERT balances power supply and demand by ensuring three concepts are consistent: (1) "gross" generation before renewable curtailments, (2) transmitted electricity after accounting for renewable curtailments, and (3) total demand.
- This update expands on this framework by including charging-related losses as a second type of power loss along with renewable curtailments.
- It also includes the new demand associated with more categories of electrification.

Figure 13 – Gross generation, transmitted power, and load (TWh)

Technology	Gross Generation	Transmitted Power
Coal	0	0
Gas	671	667
DFO	1	1
Nuclear	1,970	1,970
Hydroelectric	301	301
Wind	1,691	1,539
Solar	3,260	2,968
Geothermal	17	17
Biomass	54	54
Other	11	11
Storage Loss	0	119
Curtailments	0	328
TOTAL >>	**7,975**	**7,975**

Demand Category	Pre-T&D Losses Load
Residential	1,977
R Heat Pumps	270
Commercial	1,612
C Heat Pumps	222
Industrial	1,595
LDVs	1,543
MDVs/HDVs	213
Railroads	97
LOAD >>	**7,528**
↓	↓
Storage Loss	119
Curtailments	328
TOTAL >>	**7,975**

- Figure 13 shows the steps in this process with Baker-Shultz in 2050. Gross generation includes generation by technology. Transmitted power and gross generation and usually quite similar to each other but have two important differences:
    - Wind and solar plants have different gross and “net” generation after accounting for post-storage curtailments for unneeded energy in certain hours.
    - Power ran through a storage battery has losses associated with inefficiency.
- The difference between gross generation and transmitted power comes from post-storage curtailments (328 TWh) and storage losses (119 TWh).
- In 2050, the gross generation of wind and solar would be 4,951 TWh. Conversely, only 4,507 TWh makes it through to the transmission and distribution (“T&D”) system after accounting for the 328 TWh of post-storage curtailments.
- Approximately four TWh of the storage loss would come from gas plants being dispatched to charge up storage units. Gross generation from natural gas is slightly higher (671 TWh) than transmitted power (667 TWh) as a result.
- The load from Figure 13 is before accounting for T&D losses. In reality, T&D losses make up around 7% of transmitted power lost throughout the T&D system before it

reaches the end-use customer. Delivered electricity would be roughly 7,001 TWh of electricity after accounting for 7% losses against 7,528 TWh.

Negative Emissions

- CERT includes 45Q credits.[92] The 45Q credits follow current law in the baseline scenario and do not change because of the Baker-Shultz carbon fee.
- Though many approaches factor in negative emissions associated with land-use changes, commonly referred to as "nature-based solutions" or "NBS," CERT does not include those linkages at this time.

Energy Services and Rejected Energy

- CERT includes results organized around primary energy delivery, power generation, rejected energy, and useful energy service. An example of this sort of analysis would include diagrams produced by Lawrence Livermore National Laboratory ("LLNL") on the U.S., other nations and regions, and the global energy sector.[93]
- The process for calculating the rejected energy services includes:
  - CERT uses the implied fleetwide efficiencies[94] of thermal plants from the AEO to calculate losses associated with coal, gas, and DFO power.
  - Form EIA-923 provides the implied efficiency of most utility-scale power plants throughout the U.S. market.[95] This data has been used to estimate the thermal efficiency of the biomass fleet at 12.4% efficiency.
- The legacy nuclear fleet is modeled as 35% efficient.[96] SMRs are assumed to be 50% efficient because their smaller size might allow them to serve the combined heat and power needs of campuses, factories, and military bases.[97] Such a setup is common for thermal plants but impractical for conventional reactors.
- Hydroelectric plants are assumed to be 100% efficient. Hydro plants can be dispatched when needed and as such they are not curtailed outside of rare circumstances where a reservoir is full and cannot be used to store the potential energy of the water to be run down through the turbines later when power prices are higher.
- The loss rate for wind and solar is based on CERT's updated "Rejected Energy" calculations described in Figure 12. Wind and solar are more efficient than thermal plants but can still suffer inefficiencies through curtailments, associated battery losses, and the T&D losses experienced by all types of generation.
- T&D losses before delivery of the power to customers make up approximately 7% of generation. This phenomenon is the same for the electrification load coming onto the system from electric heat pumps, from LDVs, and from HDVs.
- The losses for direct use of gas, coal, and petroleum products are estimated with the data from LLNL by U.S. economic sector for 2022.[98] The implied rate of loss by sector (residential, commercial, industrial, and transportation) is calculated by first subtracting electricity delivery from total energy services and then calculating the ratio of remaining energy services compared to the quantity of rejected energy.
- These calculations yield the following efficiency rates[99] by sector:
  - **Residential** = 39.3% efficiency
  - **Commercial** = 31.4% efficiency

- **Industrial** = 41.5% efficiency
- **Transportation** = 20.9% efficiency

- EVs are modeled as harnessing 90% of their input electricity as power through their drivetrains.[100] The heat loss rate is much higher for ICEs.
- By 2050, the carbon fee would increase the efficiency of the U.S. energy sector – as measured by primary energy inputs compared to useful energy – in several different ways. The primary ones from CERT modeling would include:
  - Transitioning most power generation away from thermal plants (coal and gas) with relatively high loss rates to power types with much lower loss rates such as wind farms, solar farms, and the flexibility of SMRs.
  - Capturing pre-storage curtailments with battery storage units and reusing the energy on the power grid to reduce thermal dispatch later.
  - Replacing direct fossil use (especially of gas) for residential and commercial heating with the thermal efficiency of heat pumps.
  - Replacing direct fossil use (e.g., gasoline and diesel fuels) in the transportation sector with EVs and the relative efficiency of EV batteries.
- CERT projects most losses would concentrate in the energy spaces less amenable to electrification, such as industry, HDVs, air travel, and water transport.

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[1] "Bipartisan Climate Roadmap," Climate Leadership Council, February 2020. https://clcouncil.org/reports/Bipartisan-Climate-Roadmap.pdf
[2] https://thundersaidenergy.com/about-us/
[3] https://www.eia.gov/
[4] https://www.eia.gov/outlooks/aeo/
[5] https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs
[6] Thunder Said Energy maintains a suite of models for all regions of the world for energy supply and energy demand.
[7] http://tinyurl.com/5dh4s22w
[8] This "technology" is the advantage gained by gas over coal on wholesale power markets with a carbon fee. Bituminous coal produces 93 kilograms of CO_2 per million British Thermal Units ("MMBtu") and gas produces 53 kilograms of CO_2 per MMBtu. The U.S. gas fleet has an average heat rate roughly 28% less than the U.S. coal fleet. At $50 per metric ton of CO_2, the dispatch cost for coal would increase by roughly $50 per megawatt-hour ("MWh") and for gas by roughly $20 per MWh.
[9] https://thundersaidenergy.com/downloads/oxy-combustion-economics-of-zero-carbon-gas/
[10] https://thundersaidenergy.com/downloads/tag/fuel-cells/
[11] Enhanced Oil Recovery
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[18] https://windexchange.energy.gov/projects/tax-credits
[19] https://thundersaidenergy.com/downloads/hydrogen-overview-and-conclusions/
[20] https://www.eia.gov/pressroom/releases/press537.php
[21] https://www.bp.com/en/global/corporate/energy-economics/energy-outlook/hydrogen.html

[22] The load associated with vehicle charging is currently minimal but expected to grow quickly
[23] https://www.energy.gov/energysaver/heat-pump-systems
[24] CERT distinguishes between the existing 93 nuclear reactors operating at 54 nuclear power plants with approximately 95 GW of capacity and new SMRs potentially added under a carbon fee. https://www.eia.gov/energyexplained/nuclear/nuclear-power-plants.php
[25] Onshore wind, offshore wind, and solar PV
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[27] https://www.eia.gov/todayinenergy/detail.php?id=9911
[28] https://energyeducation.ca/encyclopedia/Simple_cycle_gas_plant
[29] https://energyeducation.ca/encyclopedia/Combined_cycle_gas_plant
[30] https://flowcharts.llnl.gov/sites/flowcharts/files/2023-10/US%20Energy%202022.png
[31] https://clcouncil.org/our-plan/
[32] https://www.bls.gov/data/inflation_calculator.htm
[33] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2023&cases=ref2023&sourcekey=0
[34] Footnote 5
[35] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=2-AEO2023&cases=ref2023&sourcekey=0
[36] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=2-AEO2023&cases=ref2023&sourcekey=0
[37] https://www.eia.gov/consumption/residential/
[38] https://www.eia.gov/consumption/commercial/
[39] https://www.aga.org/wp-content/uploads/2018/07/aga_study_on_residential_electrification.pdf
[40] 100% / 370% = 27%
[41] 1,000 Btus / 97% = 1,031 Btus
[42] 1,000 Btus * 100% / 370% = 270 Btus
[43] 460% efficiency at 65˚F indoors compared to 97% efficiency for gas
[44] 38% / 90% = 42.2%
[45] https://reviewed.usatoday.com/ovens/features/induction-101-better-cooking-through-science
[46] https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php
[47] 65˚F minus 42˚F equals 23 HDDs divided by 24 hours = 0.94 HDD that hour
[48] The District of Columbia is a de facto state in CERT. It uses the same temperature shape as Maryland.
[49] https://www.ncei.noaa.gov/cdo-web/search
[50] https://www.ncei.noaa.gov/
[51] https://www.noaa.gov/
[52] https://energymarkllc.com/save-with-shoulder-months/
[53] https://www.eia.gov/tools/glossary/index.php?id=Petrochemical%20feedstocks
[54] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=49-AEO2022&cases
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[56] https://electrificationcoalition.org/work/federal-ev-policy/inflation-reduction-act/
[57] https://thundersaidenergy.com/downloads/category/vehicles/
[58] https://about.bnef.com/electric-vehicle-outlook/
[59] 12,429 VMT * 0.446 KWh = 5,543 KWh or approximately 5.5 MWh of generation
[60] https://fleetnetamerica.com/blog/post/classifying-medium-and-heavy-duty-trucks/
[61] https://www.iea.org/reports/energy-efficiency-policy-and-carbon-pricing
[62] https://www.eia.gov/todayinenergy/detail.php?id=49336
[63] https://www.nature.com/articles/s41467-019-12618-3
[64] https://www.eia.gov/todayinenergy/detail.php?id=54559
[65] Energy content of transmitted electricity divided by the energy content of primary fuel inputs.
[66] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2023&cases=ref2023&sourcekey=0
[67] Nuclear plants are run at close to 100% of their capacity most of the time except for periodic outages in low-demand months to refuel the reactors and perform maintenance.
[68] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=67-AEO2023&cases=ref2023&sourcekey=0
[69] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2023&cases=ref2023&sourcekey=0
[70] https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program
[71] https://www.ge.com/gas-power/resources/education/combined-cycle-power-plants
[72] 150 GW from 2035 through 2050 equals roughly 10 GW per year.
[73] https://www.eia.gov/totalenergy/data/annual/showtext.php?t=ptb0902
[74] https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs

[75] https://world-nuclear.org/information-library/country-profiles/countries-a-f/france.aspx
[76] https://www.economist.com/business/2022/12/12/can-the-french-nuclear-industry-avoid-meltdown
[77] Footnote 75
[78] https://www.macrotrends.net/countries/FRA/france/gdp-gross-domestic-product
[79] https://sciencing.com/places-wind-turbines-produce-electricity-5159049.html
[80] https://www.nrel.gov/docs/fy13osti/56290.pdf
[81] 520 GW and 10 MW per square mile equals 52,000 square miles.
[82] 1,641 GW and 21.5 MW per square mile equals 76,325 square miles.
[83] https://www.census.gov/geographies/reference-files/2010/geo/state-area.html
[84] https://blog.ucsusa.org/steve-clemmer/how-much-land-would-it-require-to-get-most-of-our-electricity-from-wind-and-solar/
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[87] https://www.greentechmedia.com/articles/read/renewables-integration-in-the-midwest-is-a-whole-other-animal
[88] https://ieeexplore.ieee.org/document/7548268
[89] Roughly the historical curtailment rate of renewables on U.S. power markets.
[90] https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/EMM_2022.pdf
[91] https://www.eia.gov/todayinenergy/detail.php?id=46756
[92] https://www.iea.org/policies/4986-section-45q-credit-for-carbon-oxide-sequestration
[93] https://flowcharts.llnl.gov/commodities/energy
[94] Footnote 65
[95] https://www.eia.gov/electricity/data/eia923/
[96] https://energyeducation.ca/encyclopedia/Nuclear_power_plant
[97] https://www.sciencedirect.com/science/article/pii/S0360544222023635
[98] https://flowcharts.llnl.gov/commodities/energy
[99] Useful energy divided by primary energy inputs.
[100] http://large.stanford.edu/courses/2010/ph240/sun1/