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Overview

The U.S. Energy Information Administration (EIA) released its *Annual Energy Outlook 2020* (AEO2020) in January 2020. The AEO2020 Reference case generally assumes that existing laws and regulations remain as enacted throughout the projection period, including when the laws or policies are scheduled to sunset. However, in the area of policies that target emissions reduction, history has demonstrated that there is significant uncertainty in this assumption. For example, tax credits supporting wind and solar electric generation are often extended year to year, and vehicle emission standards, etc. are the subject of legislative debate and action. There are also examples, such as the Clean Power Plan, where rules are issued and later repealed. Therefore, it is important to consider the uncertainty associated with the assumption of current laws and legislation.

This *Issue in Focus* article presents a series of cases related to the uncertainty around a set of current policies including

- Accelerating carbon-free generation
- Carbon fee
- Reimbursement of residential solar photovoltaic (PV) generation at wholesale electricity prices
- Affordable Clean Energy rule

The alternative cases examined are intended to identify and quantify uncertainties in energy system model inputs associated with potential future changes in the legislative environment and to describe the effect these uncertainties could have on modeled U.S. energy markets, including total U.S. energy-related CO2 emissions.

This article discusses legislative uncertainty in the AEO2020 Reference case. It does not consider a full range of policy options available to policymakers. Furthermore, the assumptions used in the alternative cases should not be construed as EIA opinion regarding how laws or regulations should, or are likely to, be changed.

Executive summary

Each of the four sections in this paper discusses alternative cases. Unless otherwise specified, cases presented in this article start with the AEO2020 Reference case and change particular assumptions to address uncertainty about the future of selected existing laws and regulations. A summary table identifying the alternative cases and detailing their assumptions are found in Appendix 1.

50% Carbon-Free Generation case

The 50% Carbon-Free Generation case assumes that all Lower 48 states achieve at least 50% of electricity sales by 2050 from carbon-free electric generation sources. States are assumed to continue current programs, such as a Renewable Portfolio Standard (RPS) and clean energy standard (CES), and add new policies, as necessary, that achieve the 50% carbon-free generation by 2050 using a combination of generation technologies that emit little to no net CO2. These include

- Nuclear
- Existing large-scale and new hydropower
- Fossil-fuel generation with at least 90% carbon capture and sequestration
- Geothermal
- Biomass
- Solar PV (including large-scale and distributed generation)
- Solar thermal
- Onshore wind (including large-scale and distributed generation)
- Offshore wind

Wind and solar photovoltaic generation growth is similar to the AEO2020 Reference case until 2035 and 2045, respectively, when growth accelerates to reach 10% and 17% higher than the AEO2020 Reference case in 2050. Nuclear generation helps meet the carbon-free generation requirements, resulting in fewer nuclear plant retirements than in the AEO2020 Reference case and 19% higher nuclear generation by 2050. This case results in total U.S. energy-related CO2 emissions that are 3% lower in 2050 than in the AEO2020 Reference case and 7% lower in 2050 than in 2019.

Renewable Portfolio Standards Sunset case

The Renewable Portfolio Standards (RPS) Sunset case assumes that all states terminate existing RPS policies in 2020 and do not enact new RPS or carbon-free generation policies. This case illustrates the effects of current RPS policies. It shows that eliminating current state RPS requirements would reduce renewable generation by 4% by 2050 compared with the AEO2020 Reference case and that total U.S. energy-related CO2 emissions would be 1% higher in 2050 relative to the AEO2020 Reference case and 3% lower in 2050 when compared with 2019.

Carbon Fee cases

The carbon fee cases assume economy-wide implementation of a $15, $25 and $35 fee (2019 dollars per metric ton of carbon dioxide) starting in 2021. These fees increase by 5% (in real dollars) per year and reach $61.74, $102.90, and $144.06 (per metric ton of carbon dioxide), respectively, by 2050. Emissions revenues are distributed back to consumers via lump-sum payments, keeping the government deficit neutral.

The three carbon fee cases show that total energy-related CO2 emissions decline early in the projection period before leveling off in the late 2030s. The electric power sector is the most responsive to carbon fees, as coal loses market share to natural gas and renewables even faster than projected in the Reference case. The $35 carbon fee case shows total U.S. energy-related CO2 emissions would be 27% lower in 2050 than in the AEO2020 Reference case and 30% lower in 2050 when compared with 2019.

No Affordable Clean Energy Rule case

The AEO2020 Reference case includes the Affordable Clean Energy (ACE) Rule, which was issued by the U.S. Environmental Protection Agency in June 2019 to establish guidelines for states developing plans to limit carbon dioxide emissions at their coal-fired power plants. AEO2020 reflects this program in its projections by requiring that all coal plants with the potential to improve plant heat rates undertake these projects or retire by 2025. As a sensitivity case, the No ACE Rule case assumes that the existing ACE Rule is not implemented and that all coal-fired power plants continue to operate at their current efficiency levels if economical to do so.

In this case, fewer coal-fired power plants retire, and coal-fired electricity generation falls at a slower rate relative to the Reference case. By the 2040s, less-efficient coal-fired capacity is either dispatched at lower operational levels or remains in service to satisfy reserve requirements rather than to meet growing electricity demand. This case shows that total U.S. energy-related CO2 emissions would be 1% higher in 2050 than in the AEO2020 Reference case and 3% lower in 2050 when compared with 2019.

Utility Rate Structure cases

In the Reference case, residential end users who sell electricity to the grid are compensated at the retail electricity rate. The utility rate structure cases assume all distributed solar PV generation will be compensated at the wholesale or marginal price of electricity. The change in compensation increases payback periods and leads to fewer installations and less residential PV generation. With less onsite electricity generation, electricity sales from utility-scale power plants increase slightly relative to their AEO2020 case counterparts. This case shows that under Reference case assumptions total U.S. energy-related CO2 emissions would be similar in 2050 to the AEO2020 Reference case and 4% lower in 2050 when compared with 2019.

50% Carbon-Free Generation

Carbon-free generation standards have been established in several states and are usually a modification or extension of existing renewable portfolio standards (RPS). These standards are detailed in Appendix 1. Carbon-free generating technologies include nuclear, existing large-scale hydropower (also referred to as legacy hydro), and fossil generation with carbon capture and sequestration technologies as well as resources commonly allowed to qualify for RPS policies, such as new and small-scale hydroelectric, geothermal, biogenic municipal solid waste, solar photovoltaic, solar thermal, onshore wind, and offshore wind.

To illustrate the effects of existing RPS policies in the Reference case and the potential effects of extending carbon-free generation standards to all states, EIA developed two alternative cases, the 50% Carbon-Free Generation case and the RPS Sunset case.

Methodology

The 50% Carbon-Free Generation case assumes that states individually achieve a minimum 50% of state-wide electricity sales by 2050 using zero- or low-carbon generating technologies.[1] EIA assumes that carbon-free generation standards will supplement or extend existing RPS policies as follows:

- States that currently have an existing RPS policy designed to reach at least 50% carbon-free generation within the projection period maintain their existing RPS targets with no change to the suite of qualifying technologies.
- States with an RPS target of less than a 50% share from renewable generation before 2050 continue with their current RPS path to its terminal target year and then are assumed to adopt a new policy, switching to a linear path that achieves 50% carbon-free generation by 2050. States that have alternative compliance payments (ACP) as an option in their existing RPS legislation continue the ACP when the state adopts a standard of 50% carbon-free generation by 2050.
- For all other states, including states without any RPS policy and states that have an RPS policy with a terminal RPS year before 2020, are assumed to adopt a standard of 50% carbon-free generation by 2050 using the suite of carbon-free and renewable generation technologies described above, starting in 2025 with a linear progression. States with non-binding renewable portfolio goals or similar policies that are not modeled in the Reference case are included in this category.

A full index of current RPS policies for each state and their path under the 50% Carbon-Free Generation case is provided in Appendix 2.

[1] The 50% Carbon-Free Generation case as modeled requires each individual state to achieve a minimum of 50% carbon-free generation by 2050. Although trading of physical generation (subject to transmission constraints) may be used to achieve targets in any given state, there is no national target and thus no ability to trade *carbon-free generation credits* across regions to facilitate compliance.

The RPS Sunset case assumes that all states with an existing RPS policy terminate their programs in 2020 and that no new RPS or carbon-free generation standard policies are enacted. This case is intended to illustrate the effects current RPS policies have in the Reference case.

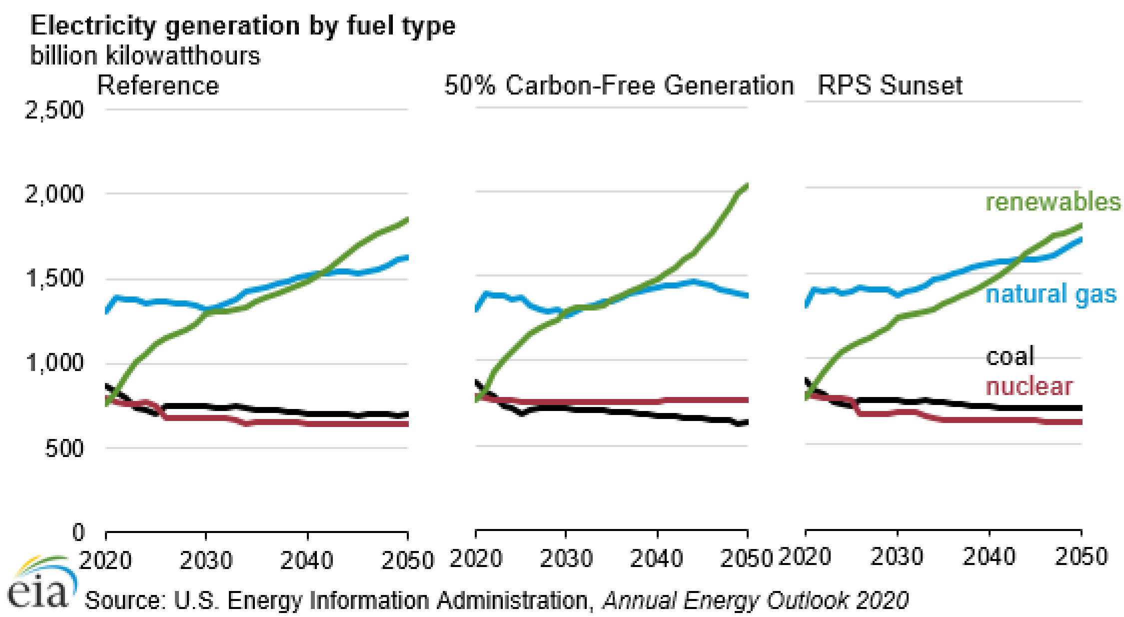
Results

Electricity generation

The assumptions in the 50% Carbon-Free Generation case and the RPS Sunset case affect the evolution of the electricity generation fuel-mix over time. Figure 1 shows electricity generation by fuel type for the Reference, 50% Carbon-Free Generation, and RPS Sunset cases.

In the 50% Carbon-Free Generation case, nuclear generation in 2050 is 124.2 billion kilowatthours (bkWh), 19.3% more than in the Reference case. There are fewer nuclear plant retirements as nuclear generation and renewables help meet the carbon-free generation requirements and limit natural gas-fired generation growth. The 50% Carbon-Free Generation case projects 244.8 bkWh (15%) less natural gas-fired generation and 57.7 bkWh (8.2%) less coal-fired generation in 2050 when compared with the Reference case.

Figure 1. Electricity generation by fuel type, 2019–2050, and changes from the Reference case in the 50% Carbon-Free Generation and RPS Sunset cases



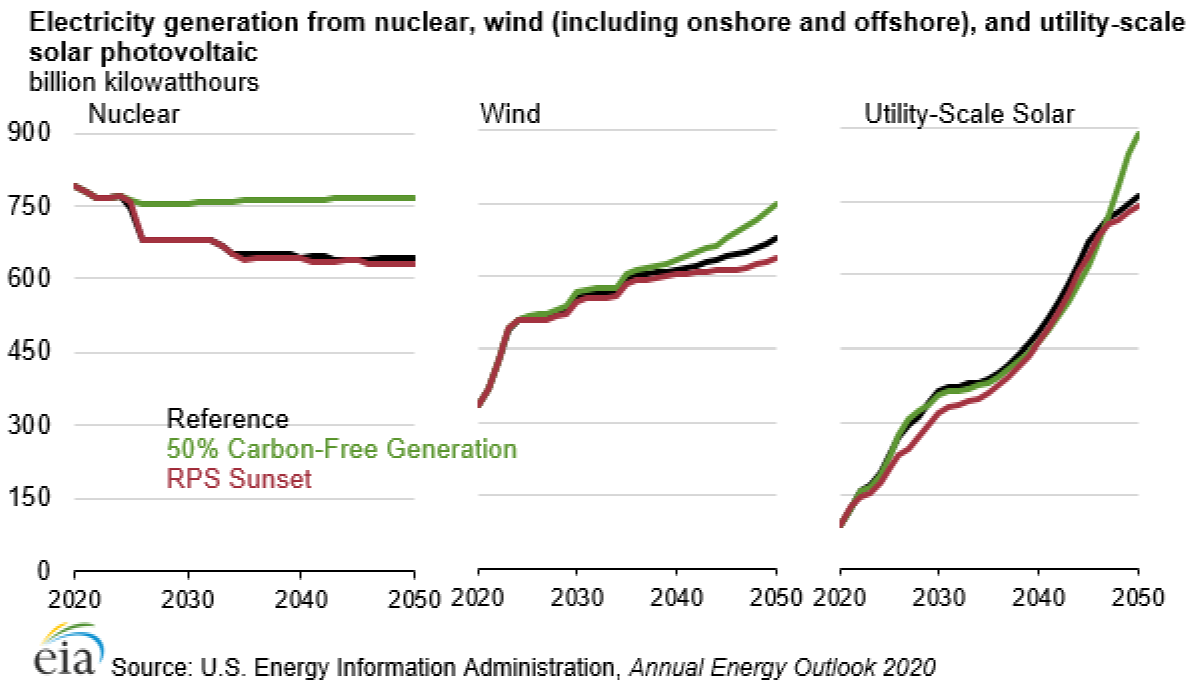
EIA models the requirement of 50% carbon-free generation of the total share of an individual state's electricity sales, but it does not impose any requirements for the balance of generation. In the AEO2020, dispatch decisions are made on economic grounds subject to the constraints of the case. In the 50% Carbon-Free Generation case, newly added carbon-free generation displaces the most expensive generation sources first. This is largely yet-to-be-built fossil-fuel (i.e., natural gas) capacity and existing natural gas generators used to provide energy at peak demand times.

Coal-fired generation between the 50% Carbon-Free Generation case and the Reference case remains largely unchanged because coal-fired generation under the 50% Carbon-Free Generation case does not face a cost for its emitted carbon, as it would under a carbon fee policy. As a result, existing coal plants operating at relatively high capacity factors with capital costs already amortized may continue to operate if their generation is less expensive than building new natural gas-fired capacity or operating natural gas-fired generation peakers.

Projected levels of nuclear generation differ between the Reference case and the 50% Carbon-Free Generation case (Figure 2). This difference is primarily the result of nuclear plants that would otherwise retire for economic reasons in the Reference case but do not retire in the 50% Carbon-Free Generation case.[2] In the side case, they are eligible to contribute to carbon-free generation and receive additional revenue[3] for doing so, making nuclear plants more economical to operate.[4] The effect of not supplying this additional revenue is most apparent after 2025 when, in the Reference case and RPS Sunset case, nuclear generation drops by 69 bkWh in the Reference case and 78 bkWh in the RPS Sunset case, with 8.8 gigawatts (GW) of retirements projected at the end of 2025 in the Reference case. Under the 50% Carbon-Free Generation case, these plants continue to operate. Small increases in nuclear generation in the later years are due to modeled uprates of the remaining nuclear fleet, which slightly increase the overall capacity of and generation from each remaining plant.

[2] No new nuclear plants are built in either of these cases.
[3] Under most existing renewable portfolio standards, qualifying generation may receive additional payments in the form of renewable energy credits (REC), or in this case carbon-free generation credits, that represent the incremental cost of the generation needed to meet the target. In proposals for national generation standards, this REC payment may be tradable among states or regions of the country, but the case analyzed here assumes that these credits are not tradable and that physical generation within each state is required.
[4] The only nuclear retirements in this case are plants that have already reported their impending retirement to EIA as of October 2019.

Figure 2. Electricity generation from nuclear, wind (including onshore and offshore), and utility-scale photovoltaic in the Reference, 50% Carbon-Free Generation, and RPS Sunset cases



As seen in Figure 2, wind generation in the 50% Carbon-Free Generation case remains unchanged relative to the Reference case until 2035, when growth accelerates and reaches a level in 2050 that is 10.3% higher than in the Reference case. Photovoltaic solar generation, including both utility-scale and end-use solar, similarly remains unchanged relative to the Reference case until 2045. After 2045, utility-scale solar generation increases until it is 16.7% more than in the Reference case in 2050.

In the RPS Policies Sunset case, there is 65.5 bkWh (3.6%) less generation from renewables than in the Reference case in 2050, which is largely offset by a 61.9 bkWH (3.8%) increase in natural gas-fired generation. In the Reference case, RPS eligible generation, as shown in Figure 3, exceeds the total renewable generation requirement through 2050 suggesting that it is largely being built for economic reasons. Under the 50% Carbon-Free Generation case, this excess renewable generation, as well as generation from existing nuclear and large-scale hydroelectric plants, is more than sufficient to meet the early year targets.

Figure 3. AEO2020 Reference case and 50% Carbon-Free Generation case total qualifying renewables generation required for combined state renewable portfolio standards and projected total generation from compliant technologies, 2020–2050

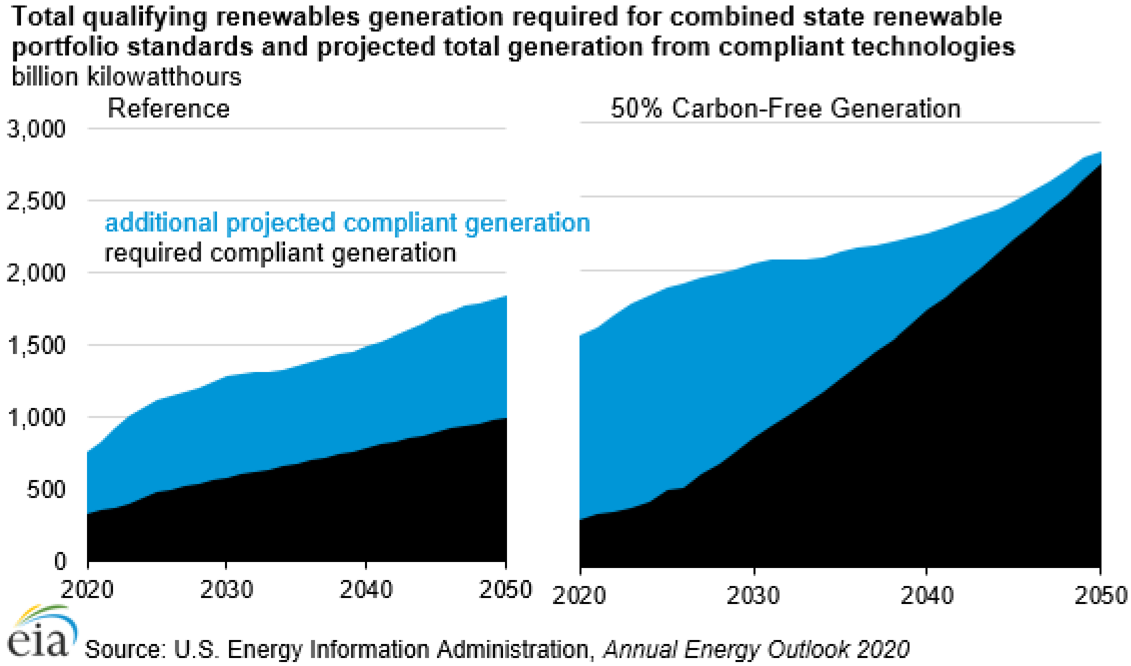
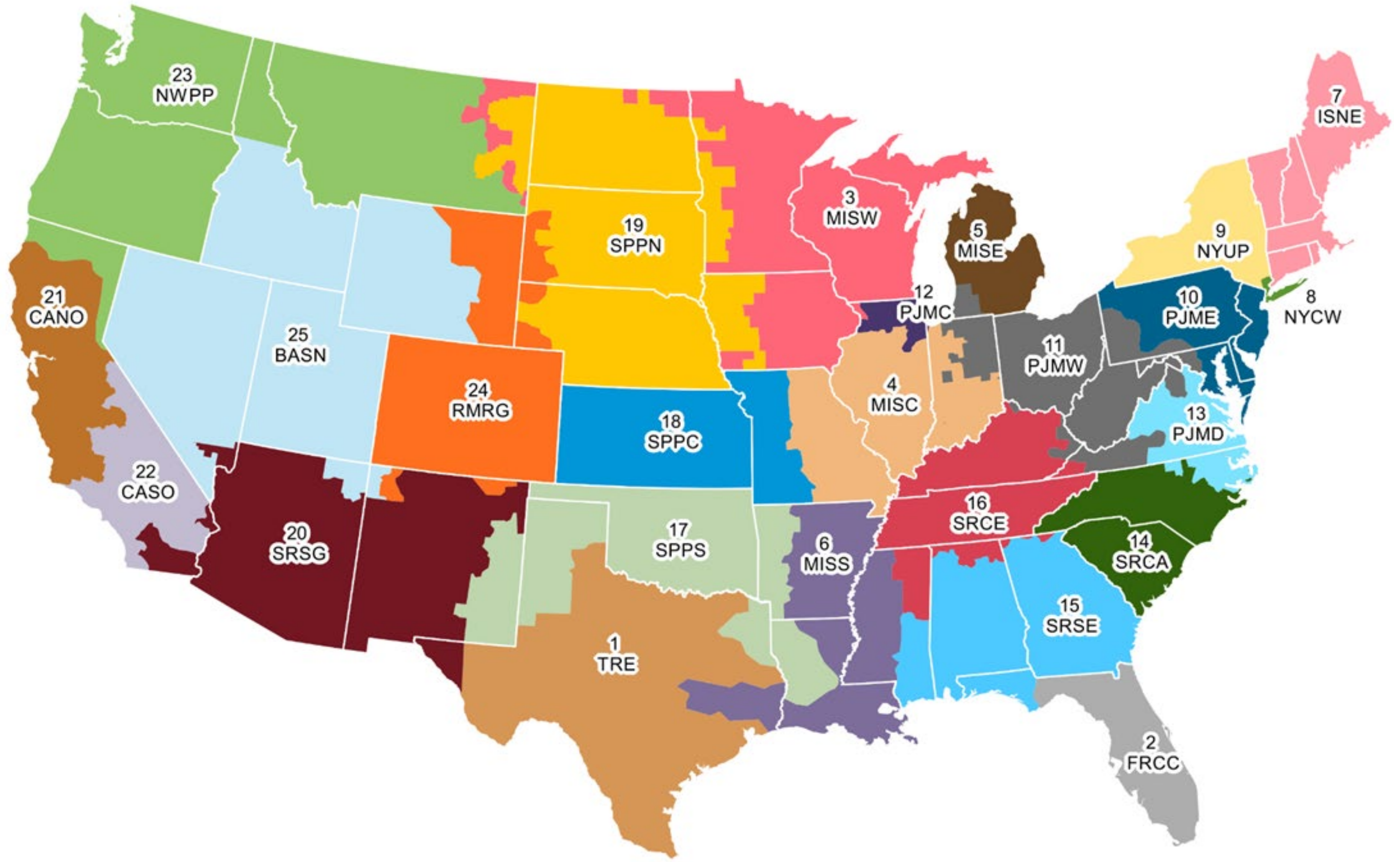


Figure 4. Electricity Market Module regions



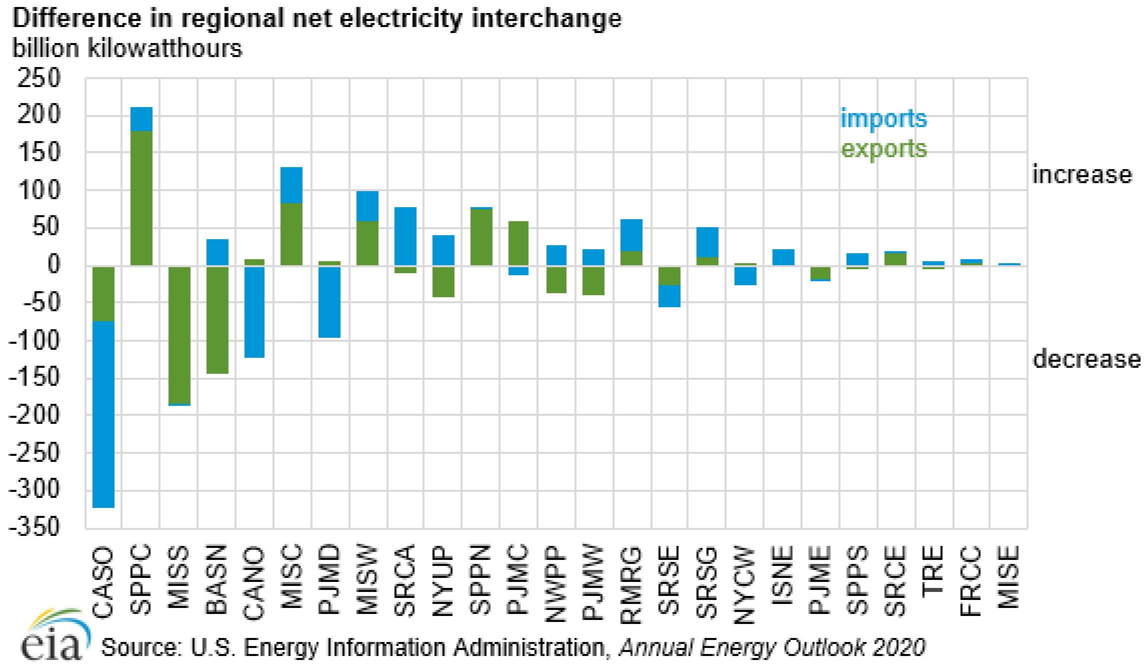
Region ID	NERC/ISO subregion	Geographic name*	Region ID	NERC/ISO subregion	Geographic name*
1- TRE	Texas Reliability Entity	Texas	14- SRCA	SERC Reliability Corporation/East	Carolinas
2- FRCC	Florida Reliability Coordinating Council	Florida	15- SRSE	SERC Reliability Corporation/Southeast	Southeast
3- MISW	Midcontinent ISO/West	Upper Mississippi Valley	16- SRCE	SERC Reliability Corporation/Central	Tennessee Valley
4- MISC	Midcontinent ISO/Central	Middle Mississippi Valley	17- SPPS	Southwest Power Pool/South	Southern Great Plai
5- MISE	Midcontinent ISO/East	Michigan	18- SPPC	Southwest Power Pool/Central	Central Great Plains
6- MISS	Midcontinent ISO/South	Mississippi Delta	19- SPPN	Southwest Power Pool/North	Northern Great Plai
7- ISNE	NPCC/ New England	New England	20- SRSG	WECC/Southwest	Southwest
8- NYCW	NPCC/NYC & Long Island	Metropolitan New York	21- CANO	WECC/CA North	Northern California
9- NYUP	NPCC/Upstate NY	Upstate New York	22- CASO	WECC/CA South	Soutshern Californi
10- PJME	PJM/East	Mid-Atlantic	23- NWPP	WECC/Northwest Power Pool	Northwest
11- PJMW	PJM/West	Ohio Valley	24- RMRG	WECC/Rockies	Rockies
12- PJMC	PJM/Commonwealth Edison	Metropolitan Chicago	25- BASN	WECC/Basin	Great Basin
13- PJMD	PJM/Dominion	Virginia			

NPCC = Northeast Power Coordinating Council, WECC = Western Electricity Coordinating Council

* Names are intended to be approximately descriptive of location. Exact regional boundaries do not necessarily correspond to state borders or to other regional naming conventions.

Source: U.S. Energy Information Administration.

Figure 5. Difference in regional net electricity interchange from Reference case by region for 50% Carbon-Free Generation case in 2050



Because EIA's assumptions in the 50% Carbon-Free Generation case are modeled on a state level rather than through implementing a single national policy, carbon-free credits (similar to renewable energy credits) cannot be used to facilitate compliance between regions with low-cost carbon-free generation options and those with higher costs. However, physical electricity trading occurs among regions and between states and is affected by the 50% carbon-free generation target by 2050.

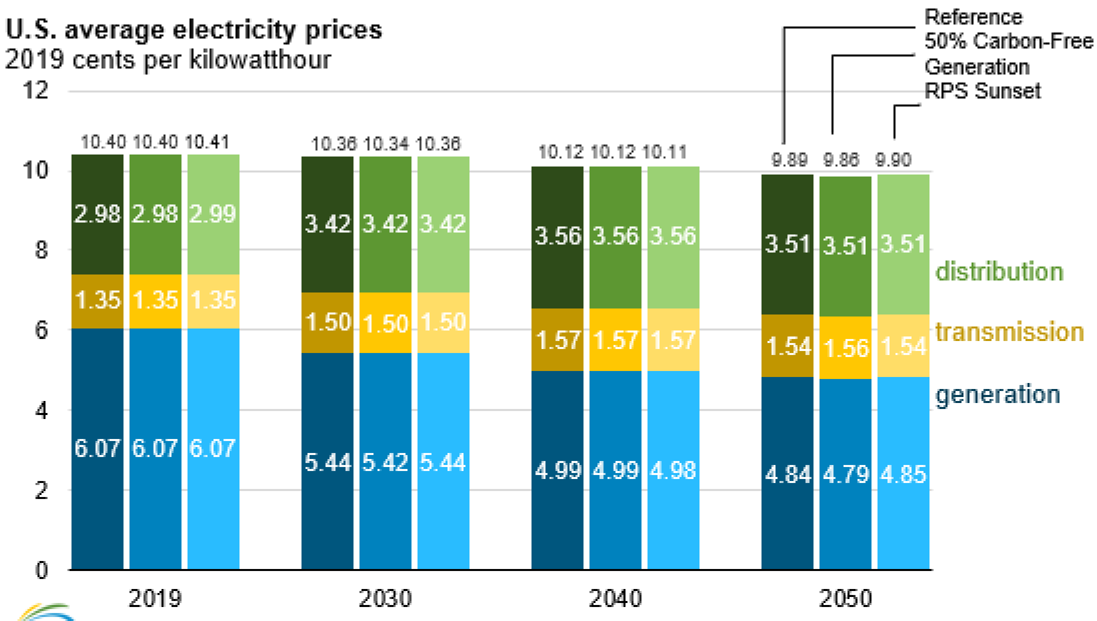
The model allows physical electricity trading among regions and between states. Regions that have higher RPS targets in the Reference case generally see their imports decrease as neighboring regions use their own qualifying generation to meet their respective RPS goals under the 50% Carbon-Free Generation case. Regional trading changes in the 50% Carbon-Free Generation case generally involve a decrease in exports from regions that either have no or low RPS in the Reference case, because those states use the qualifying generation they produce to meet their own targets instead in the 50% Carbon-Free Generation case.

A map of the 25 regions is provided in Figure 4. Changes in imports and exports between the Reference case and the 50% Carbon-Free Generation case are shown in Figure 5. In the Southern Great Plains (SPPC), exports increase by 178 bkWh between the Reference case and the 50% Carbon-Free Generation case. In the Mississippi Delta (MISS), exports decline the most out of any region, decreasing by 185 bkWh. In Northern California (CANO) and Southern California (CASO) (comprising most of California), imports significantly decrease by 124 bkWh and 248 bkWh, respectively, between the Reference case and the 50% Carbon-Free Generation case. In Virginia (PJMD), imports also decrease by 96 bkWh between the Reference case and 50% Carbon-Free Generation case.

Electricity prices, natural gas use, and carbon

All-sector average electricity prices vary minimally, between 9.86 to 9.90 cents/kWh (2019 dollars) across the Reference case, 50% Carbon-Free Generation case, and RPS Sunset case. The deviations grow in the later years, as additional renewables penetration lowers the generation cost component, which is only partly offset by higher transmission costs (Figure 6).

Figure 6. U.S. average electricity prices in the Reference, 50% Carbon-Free Generation and RPS Sunset cases, 2019–2050

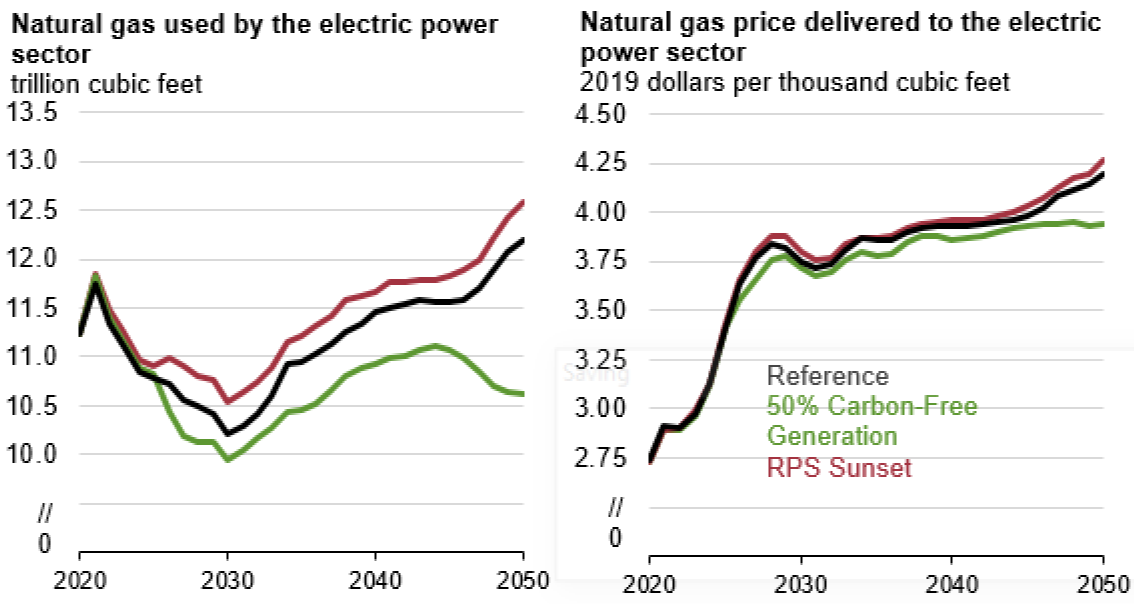


Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Figure 7 shows that natural gas use by the electric power sector differs across the three cases. As individual states rely on renewables and nuclear to meet their zero- or low-carbon mandates in the 50% Carbon-Free Generation case, less natural gas is used to meet electricity demand relative to the Reference case. This shift results in a 13.0% decline in natural gas used by the electric power sector in 2050 in the 50% Carbon-Free Generation case compared with the Reference case. In the RPS Sunset case, 3.2% more natural gas is used by the electric power sector compared with the Reference case by 2050.

Natural gas prices delivered to the electric power sector in the 50% Carbon-Free Generation case is \$0.26 per million British thermal units (MMBtu) lower than in the Reference case. The price in the RPS Sunset case is \$0.07 per MMBtu higher relative to the price in the Reference case.

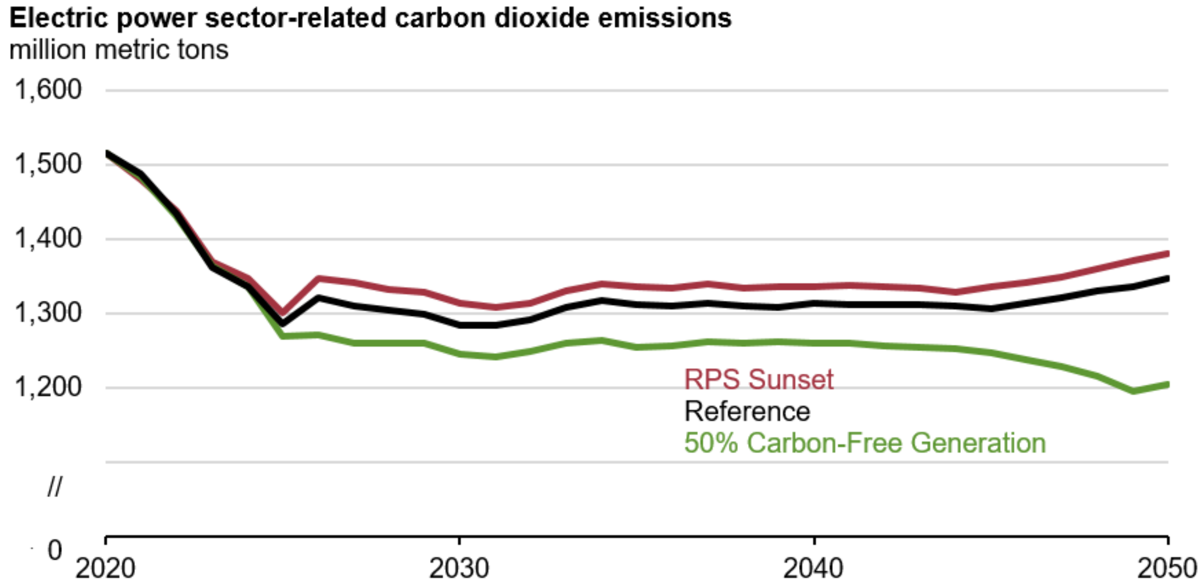
Figure 7. Natural gas consumption and price in the Reference, 50% Carbon-Free Generation, and RPS sunset cases, 2019–2050



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Electricity-related CO2 emissions across all three cases diverge in 2025 (Figure 8). Before 2025, electricity-related CO2 emissions decline in all cases as a result of retiring coal-fired generating plants. The retirement of coal-fired generating plants is driven by factors such as continued low natural gas prices (compared with history), compliance with the Affordable Clean Energy Rule (ACE Rule), and slow growth in electricity demand. After the ACE Rule takes full effect by 2025, electricity-related CO2 emissions increase slightly in the Reference case and RPS Sunset case because the remaining coal-fired generating plants are more efficient but have higher utilization rates, and new natural gas capacity is added to compensate for the drop in capacity from the retired coal plants under the ACE Rule. In 2050, CO2 emissions from the electricity sector in the 50% Carbon-Free Generation case are 10.5% lower than in the Reference case because additional zero- or low-carbon generation resources contribute a higher share of generation, compared with the Reference case, which projects more generation from natural gas. Continued use of natural gas and less utilization of renewables and nuclear generation in the RPS Sunset case results in electricity-related CO2 emissions that are 2.6% higher relative to the Reference case by 2050.

Figure 8. Electricity generation-related carbon dioxide emissions in the electric power sector in the Reference, 50% Carbon-Free Generation and RPS Sunset cases, 2019–2050



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Carbon Fees

The AEO2020 Reference case generally assumes that existing laws and regulations remain as enacted throughout the projection period, including when the laws or policies are scheduled to sunset. However, in the area of policies that target emissions reduction, history has demonstrated that there is significant uncertainty in this assumption. To examine the effects of this uncertainty across the energy sector, EIA modeled three levels of economy-wide carbon fees. These fees apply only to CO2 from energy combustion and do not include other gases such as methane.

Methodology

The three carbon fee cases start with fees of $15, $25, and $35 per metric ton (mt) of CO2 beginning in 2021. The fees rise by 5% per year in real 2019 dollars during the projection period, as shown in Table 1. Incorporating CO2 fees increases the costs of certain forms of energy and reduces total consumer disposable income in the economy; returning revenues to consumers helps offset some of the loss in disposable income but does not completely mitigate it. EIA did not consider distributional effects within consumer segments in this analysis.

Table 1. Economy-wide carbon dioxide emissions prices in the AEO2020 carbon fee side cases (2019 dollars per metric ton of carbon dioxide)

Carbon fee case	Carbon fee in 2021	Carbon fee in 2050
$15 Carbon Fee case	$15.00	$61.74
$25 Carbon Fee case	$25.00	$102.90
$35 Carbon Fee case	$35.00	$144.06

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Results

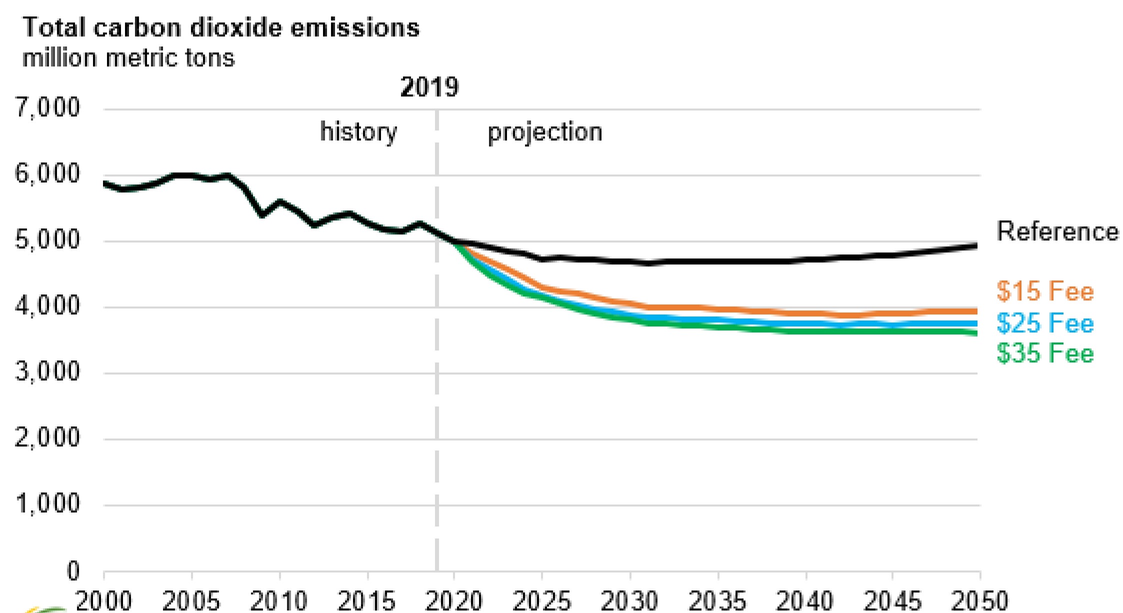
All three carbon cases show that energy-related CO2 emissions decline before leveling off in the past 10 to 15 years. In all but the $35 Fee case, emissions begin to rise at the end of the projection period despite increasing fees. Table 2 and Figure 9 show the allowance fees in selected years in real and nominal dollars, the resulting CO2 emissions from combustion, and the incremental differences in annual emissions from the previous time period (e.g., five years before). These results vary across time, fuels, and sectors of the economy.

Table 2. Carbon fees, annual energy-related carbon dioxide emissions for selected years, and changes in annual emissions from previous time period for the Reference case and carbon fee cases

Cases	2020	2025	2030	2035	2040	2045	2050
Reference case							
Fee in 2019$ per metric ton	$0	$0	$0	$0	$0	$0	$0
Fee in nominal dollars per metric ton	$0	$0	$0	$0	$0	$0	$0
Annual CO2 emissions (million metric tons)	4,993	4,733	4,674	4,691	4,715	4,782	4,922
Annual change from previous time (million metric tons)		-260	-59	18	24	67	140
$15 Fee case							
Fee in 2019$ per metric ton	$0	$18	$23	$30	$38	$48	$62
Fee in nominal dollars per metric ton	$0	$21	$31	$44	$62	$89	$128
Annual CO2 emissions (million metric tons)	5,004	4,302	4,037	3,968	3,902	3,895	3,932
Annual change from previous time (million metric tons)		-702	-264	-70	-66	-7	37
$25 Fee case							
Fee in 2019$ per metric ton	$0	$30	$39	$49	$63	$81	$103
Fee in nominal dollars per metric ton	$0	$35	$51	$73	$104	$149	$216
Annual CO2 emissions (million metric tons)	5,005	4,165	3,883	3,800	3,742	3,734	3,749
Annual change from previous time (million metric tons)		-839	-283	-83	-58	-8	14
$35 Fee case							
Fee in 2019$ per metric ton	$0	$43	$54	$69	$88	$113	$144
Fee in nominal dollars per metric ton	$0	$50	$72	$103	$147	$211	$305
Annual CO2 emissions (million metric tons)	5,005	4,132	3,804	3,693	3,636	3,617	3,610
Annual change from previous time (million metric tons)		-873	-328	-111	-57	-19	-7

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Figure 9. Total carbon dioxide emissions for the Reference case and carbon fee cases



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Fuels

Carbon fees affect fossil fuels and non-carbon-emitting alternative fuels differently. The factors that influence the response to the carbon fees include the carbon intensity of the fuel (CO_2/British thermal unit [Btu]), the efficiency and carbon intensity of the fuel's production, the demand response of the fuel to changes in the fuel's price, and whether substitute energy sources are readily available.

Coal

Coal is mainly used as an energy source in the electric power and industrial sectors. Coal is the most carbon-intensive fossil fuel with a typical intensity of about 95 kilograms of CO_2 per million Btu (kg CO_2/MMBtu) of energy consumed. In the electric power sector, coal competes directly with natural gas (the least carbon-intensive fossil fuel) and renewable generation. Because of its carbon intensity and ready availability of substitutes in the power sector, coal consumption decreases dramatically by 2025 in all carbon fee cases, and most of this decline occurs in the electric power sector. Most of the remaining coal consumption and related emissions after 2025 occur in the industrial sector where substitutes are not as readily available in certain industrial processes, which are therefore less sensitive to a CO_2 fee.

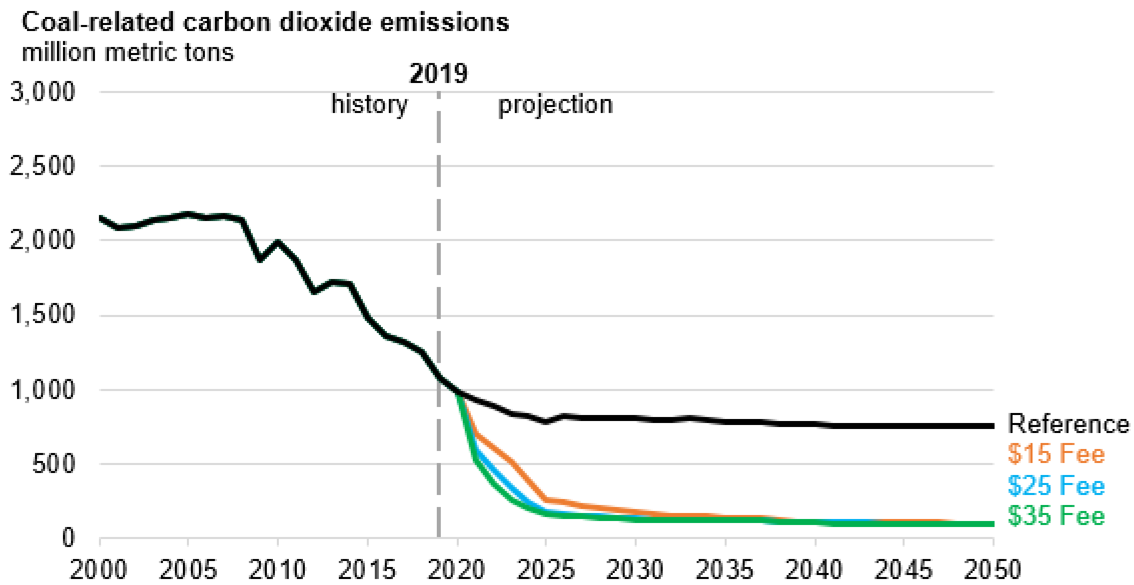
In the Reference case, many coal generating plants continue to operate under current policies, and coal-related CO_2 emissions in 2050 are more than seven times higher than in the carbon fee cases as shown in Figure 10.

Table 3. Changes in annual coal-related CO_2 emissions across selected years of the carbon fee cases

Cases	2020	2025	2030	2035	2040	2045	2050
$15 Fee case							
Fee in 2019$ per metric ton	$0	$18	$23	$30	$38	$48	$62
Fee in nominal dollars per metric ton	$0	$21	$31	$44	$62	$89	$128
Annual CO_2 emissions (million metric tons)	982	257	183	143	115	105	102
Annual change from previous time (million metric tons)		-725	-74	-39	-28	-10	-3
$25 Fee case							
Fee in 2019$ per metric ton	$0	$30	$39	$49	$63	$81	$103
Fee in nominal dollars per metric ton	$0	$35	$51	$73	$104	$149	$216
Annual CO_2 emissions (million metric tons)	982	178	135	122	107	103	100
Annual change from previous time (million metric tons)		-804	-43	-13	-15	-4	-3
$35 Fee case							
Fee in 2019$ per metric ton	$0	$43	$54	$69	$88	$113	$144
Fee in nominal dollars per metric ton	$0	$50	$72	$103	$147	$211	$305
Annual CO_2 emissions (million metric tons)	982	165	131	120	105	101	98
Annual change from previous time (million metric tons)		-817	-35	-11	-15	-4	-4

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Figure 10. Coal-related carbon dioxide emissions for the Reference case and carbon fee cases

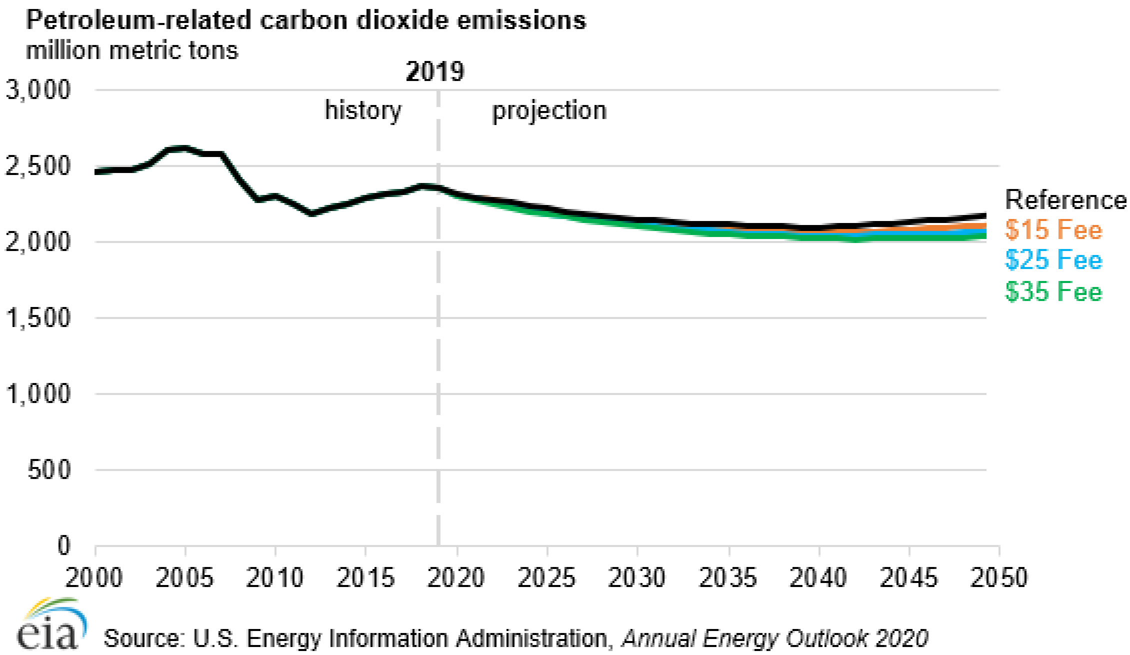


Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Petroleum

Petroleum is an energy source used in all sectors of the U.S. economy, but it is most significantly used in the transportation and industrial sectors. The carbon intensity of the major petroleum products ranges from 70.9 kg CO2/MMBtu for jet fuel to 78.8 kg CO2/MMBtu for residual fuel oil, with motor gasoline at 71.3 kg CO2/MMBtu. The difference in projected petroleum consumption between the Reference case and carbon fee cases is relatively small because, despite rising fuel prices, the opportunities for fuel substitutions in the transportation sector are limited during the projection period with the carbon fee levels examined. Demand for petroleum in certain industrial applications such as refining and bulk chemicals is also relatively price-insensitive. As a result, by 2050, the range between the Reference case and the $35 Fee is 7% (145 million metric tons [MMmt]) (Figure 11).

Figure 11. Petroleum-related carbon dioxide emissions for the Reference case and carbon fee cases

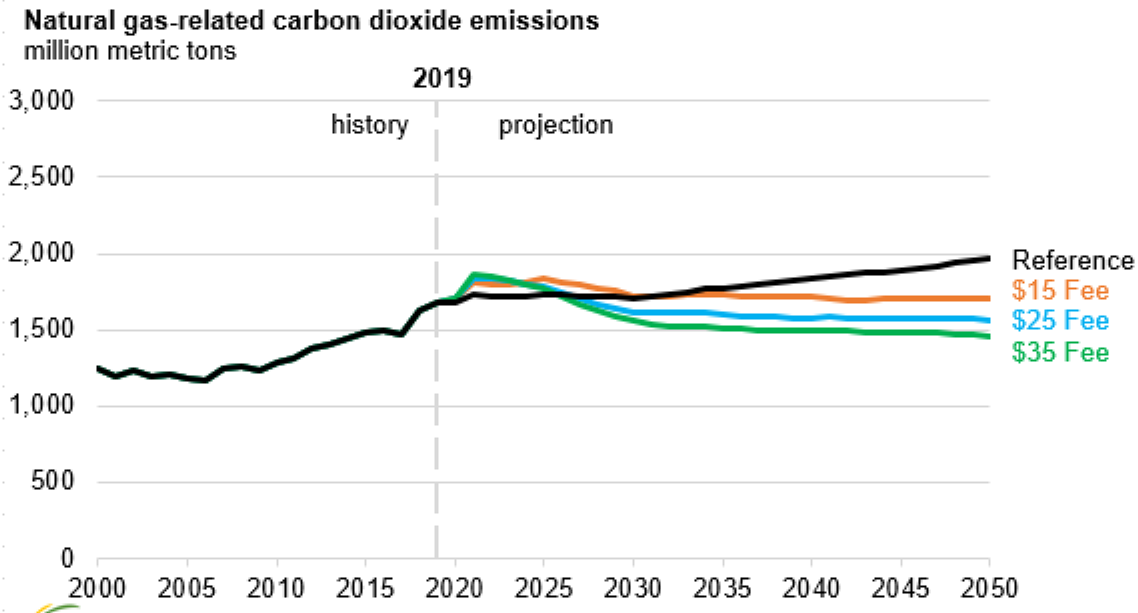


Natural gas

Natural gas has multiple uses in the U.S. energy economy, and more natural gas is consumed in the electric power sector than in the industrial sector. Natural gas is also an important fuel in the residential and commercial sectors primarily because of its use in space heating, water heating, and cooking. Because natural gas is the least carbon intensive of the fossil fuels (53 kg CO2/MMBtu), it plays a unique role in response to carbon fees.

In the early stages of the projection period, natural gas-related CO2 emissions exceed the Reference case in all of the carbon fee cases because natural gas-fired generation in the power sector, as with other lower-carbon intensive sources of generation, increases as coal-fired generation decreases. With the relatively low carbon fees associated with its emissions in these early years of the projection period, natural gas-fired generation continues to be economically competitive, and its associated emissions continue to grow. However, as the carbon fee increases over time, natural gas-fired generation and its associated emissions decrease, and the decrease varies with carbon fees across the three cases. After the mid-2030s, natural gas-related CO2 emissions remain below the Reference case in all three carbon fee cases (Figure 12).

Figure 12. Natural gas-related carbon dioxide emissions for the Reference case and carbon fee cases



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Energy sectors

Electric power sector

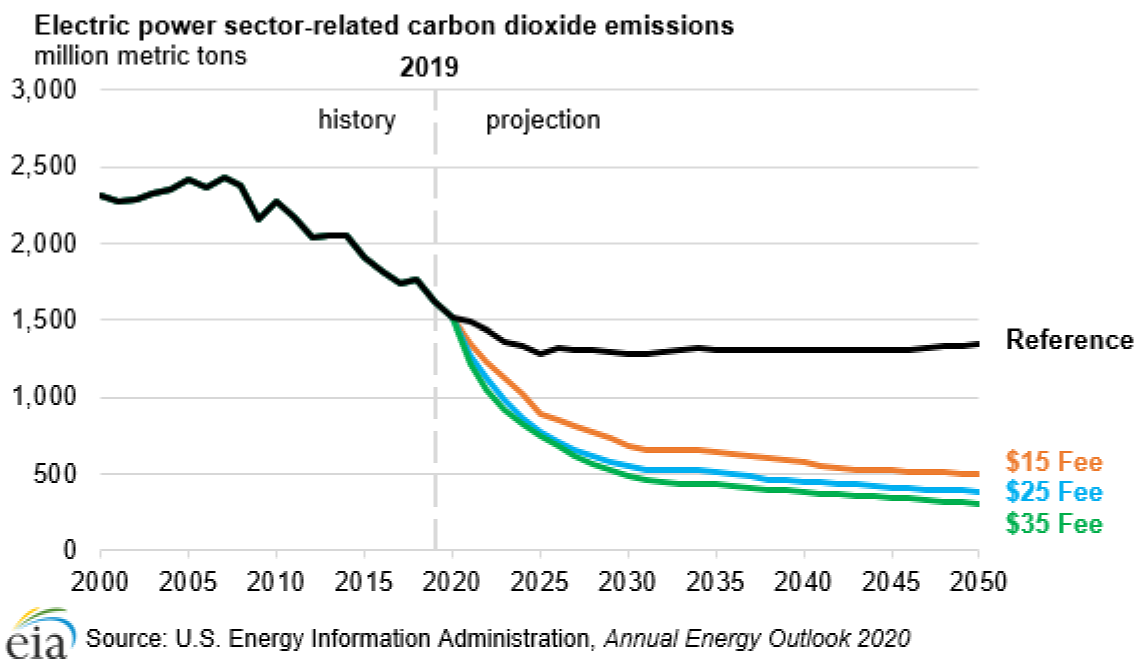
The electric power sector is an energy transformation sector that transforms primary energy into electrical energy that is sold to consumers in the end-use sectors. In the end-use sectors discussed below, EIA attributes electricity-related CO2 emissions to each sector proportionally by electricity sales to that sector.

Fuel substitution is relatively easy in the electric power sector so coal is displaced by natural gas and renewables in the carbon fee cases. In addition, less nuclear power capacity is retired in the carbon fee cases. In the Reference case, 24 gigawatts (GW) of nuclear capacity are retired. In the $15 Fee case, only 9 GW are retired and in both the $25 Fee case and $35 Fee case, only 8 GW are retired. Electric generation emissions that EIA attributes to the residential and commercial sectors (which depend most heavily on electricity) decline the most because coal is displaced by low-emitting natural gas and non-emitting renewables. Emissions attributed to the industrial sector decline less because the sector uses more petroleum and natural gas and because fewer opportunities exist for fuel switching. Emissions decline the least in the transportation sector because it consumes a relatively small amount of electricity and because the fees considered did not induce widespread growth in electric vehicles in the model.

The declining CO2 emissions from the electric power sector continues its historical trend in which natural gas replaces coal in generation because it has become cost competitive. In addition, state-level renewable portfolio standards and federal tax incentives encourage renewable capacity growth, which further reduces coal generation. In the Reference case, this trend ends in 2025 as coal generation begins leveling off and emissions plateau thereafter. In contrast, in the carbon fee cases, coal-fired generation continues to retire as carbon fees increase fuel costs. Wind and solar generation increase to compensate for the reduction in coal-fired generation. Wind generation increases 97% by 2050 from 2019 in the Reference case, compared with 214%, 228%, and 235% by 2050 in the $15 Fee case, $25 Fee case, and $35 Fee case, respectively. Similarly, solar photovoltaic generation increases more than 800% by 2050 in the Reference case, compared with 1292%, 1340%, and 1387% by 2050 in the $15 Fee case, $25 Fee case, and $35 Fee case, respectively.

Natural gas exhibits a relatively complex generation pattern in all three carbon fee cases. As coal-fired generation declines quickly after the imposition of a CO2 fee, natural gas generation grows to compensate because logistical considerations limit the growth rate of new renewable generation capacity. As a result, while total U.S. energy-related emissions decrease throughout the projection period, CO2 emissions from natural gas exceed those in the Reference case through 2025. In the $35 Fee case, natural gas emission levels are lower than in the Reference case starting in 2026 and in the $25 Fee case starting in 2027. In the $15 Fee case, emission levels are not lower than the Reference case until 2031 (Figure 12).

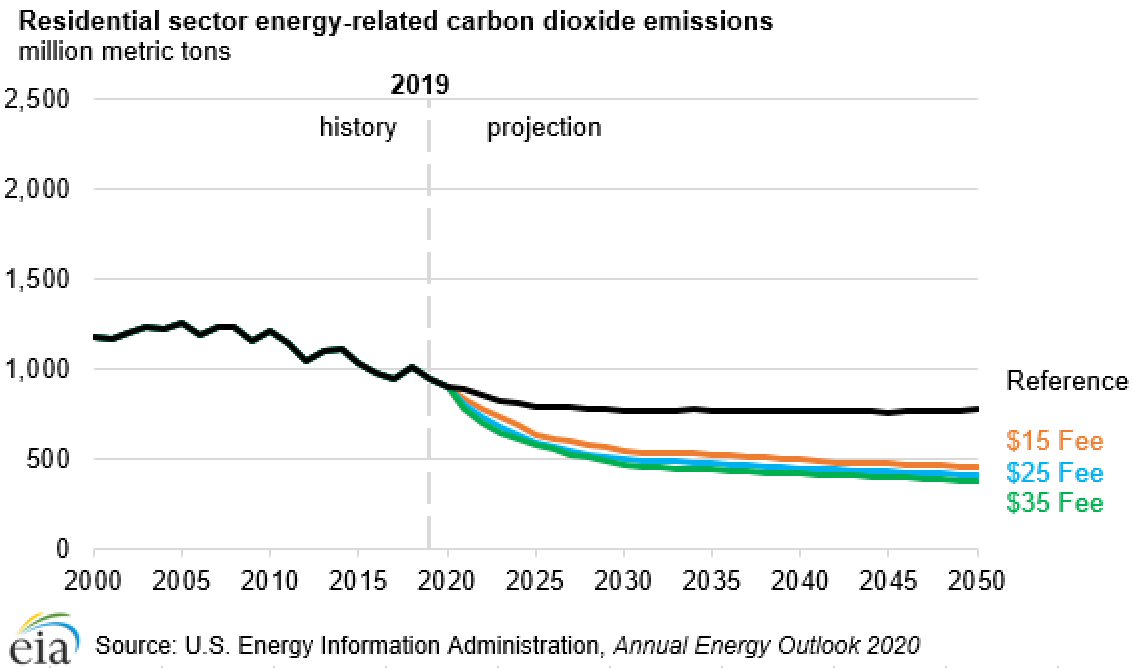
Figure 13. Electric power sector carbon dioxide emissions for the Reference case and carbon fee cases



Residential sector

The U.S. residential sector consumed 4.9 quadrillion Btu of electricity in 2019, or 42% of its total delivered energy consumption. Uses include heating and cooling as well as water heating and refrigeration. Because of the residential sector's relatively large share of consumption of electric power, it exhibits a proportionally large response to the decline in coal-related emissions from electricity generation through the application of carbon fees. Of the 573 MMmt decline in energy-related CO2 in the residential sector during the projection period in the $35 Fee case, 87% is because of the reduction in carbon dioxide related to electricity purchased from the electric power sector. By 2050, CO2 emissions in the $35 Fee case are 51% lower than the Reference case (Figure 14).

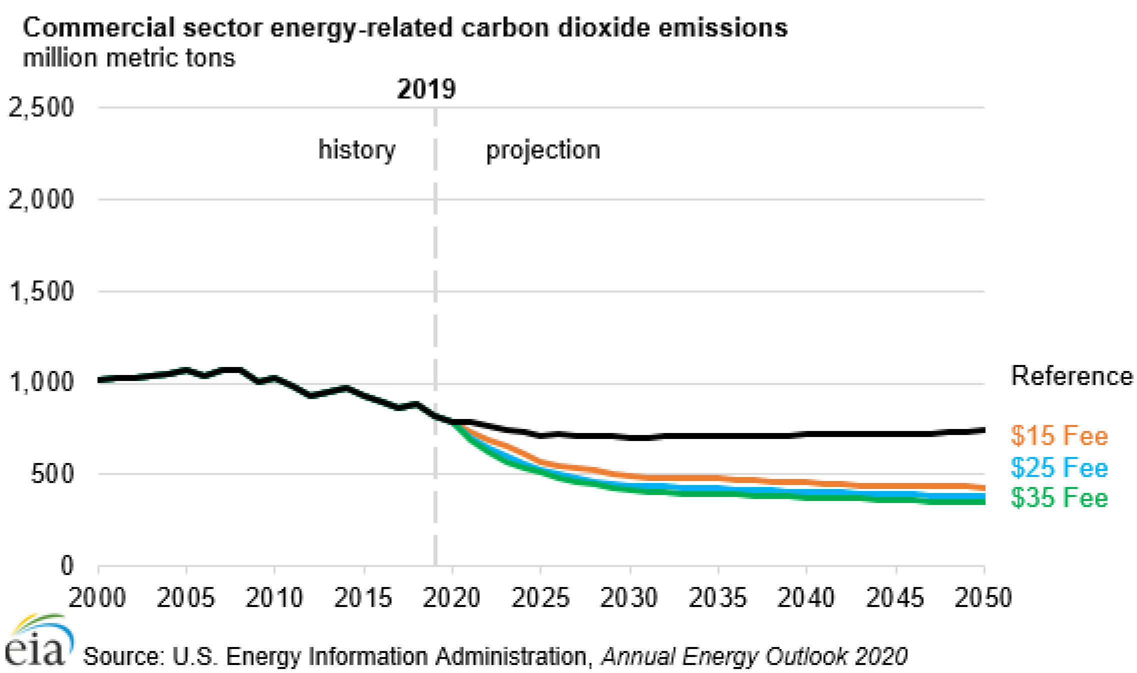
Figure 14. Residential sector carbon dioxide emissions for the Reference case and carbon fee cases



Commercial sector

The U.S. commercial sector relies on electricity for much of its energy, especially for lighting and refrigeration. As a result, 96% of the 477 MMmt commercial sector decline in CO2 emissions by 2050 in the $35 Fee case is from the decline in electricity-related emissions. In addition, in the $35 Fee case, CO2 emissions are 53% lower than the Reference case in 2050 (Figure 15).

Figure 15. Commercial sector carbon dioxide emissions for the Reference case and carbon fee cases

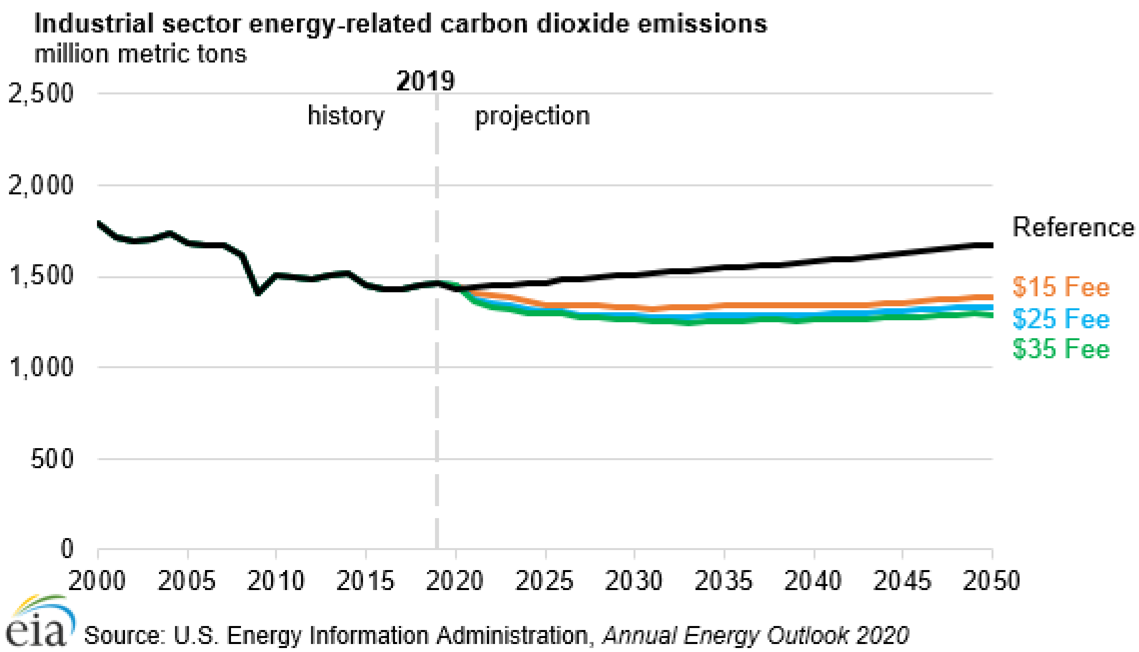


Industrial sector

The U.S. industrial sector is extremely heterogeneous and consumes a complex mix of fuels—many of them petroleum based. Natural gas is the predominant fuel and is mainly used for combined-heat-and-power generation. Electricity purchases play a relatively smaller role. Although emissions decline in the carbon fee cases relative to the Reference case (Figure 16), the difference is smaller than in the residential and commercial sectors, and emissions begin increasing after 2040 as gross output continues to rise with growing gross domestic product (GDP) assumptions.

The response to carbon fees varies by industry. For example, energy-intensive industries without readily substitutable alternative fuels, such as the bulk chemicals industry, show a relatively small reduction in CO2 emissions with carbon fees. In the $35 Fee case, there is a 29% increase in emissions from the bulk chemicals sector between 2019 and 2050, compared with a 53% increase during the same period in the Reference case.

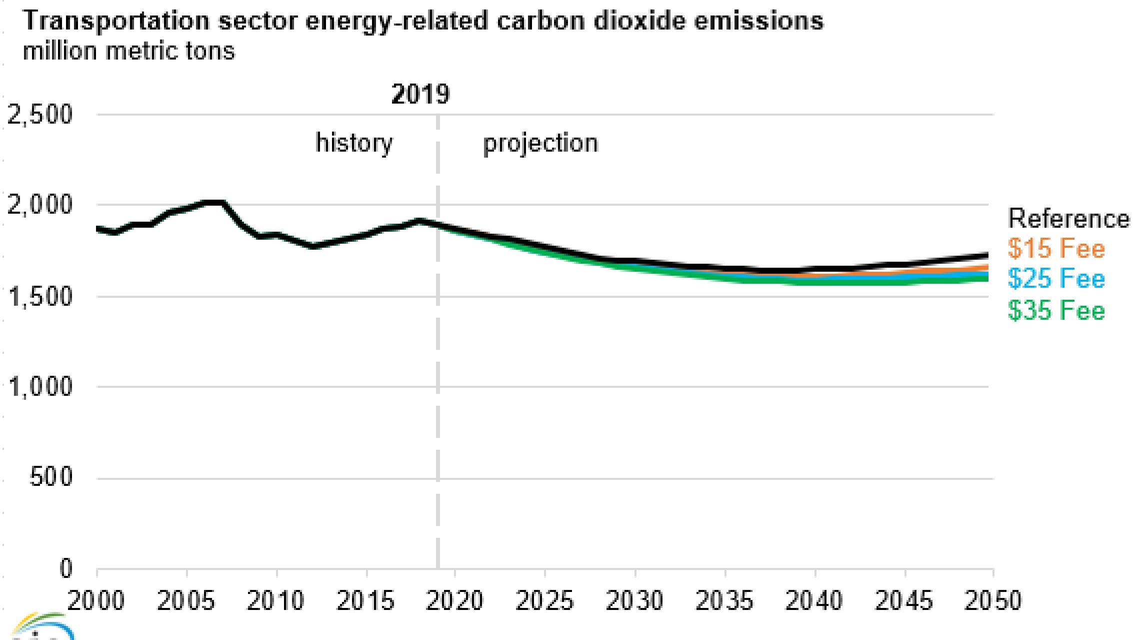
Figure 16. Industrial sector carbon dioxide emissions for the Reference case and carbon fee cases



Transportation sector

Three modes of transportation account for 85% of the energy in the sector: light-duty vehicles (LDV) (15 quadrillion Btu in 2019), freight trucks (6 quadrillion Btu in 2019), and air travel (3 quadrillion Btu in 2019) in the Reference case. As indicated in Figure 17, by 2050, the difference in CO2 emissions from the transportation sector between the Reference case and the $35 Fee case is 136 MMmt of CO2 (8%).

Figure 17. Transportation sector carbon dioxide emissions for the Reference case and carbon fee cases



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

LDV CO_2 emissions decline 29% by 2050 in the $35 Fee case, 7 percentage points more than in the Reference case. CO_2 emissions from freight trucks decline 2% by 2050 in the Reference case and 11% in the $35 Fee case. Air travel emissions increase by 36% from 2019 to 2050 in the Reference case. By comparison, air travel emissions still increase 33% by 2050 in the $35 Fee case—illustrating the insensitivity of air travel-related CO_2 emissions to a fee on those emissions.

Emissions from all other transportation fuels combined decline 1% in the Reference case and 6% in the $35 Fee case. Even with 8% annual growth in electricity sales to the transportation sector during the projection period in the $35 Fee case, petroleum remains the dominant transportation fuel at this level of carbon fee (Table 4).

Table 4. Total change in carbon dioxide emissions by transportation type and case (2019–2050)

Types of transportation	Reference	$15 Fee	$25 Fee	$35 Fee
Light-duty vehicles	-22%	-26%	-28%	-29%
Freight trucks	-2%	-6%	-9%	-11%
Air travel	36%	35%	34%	33%
All other	-1%	-4%	-5%	-6%
Total	-8%	-12%	-14%	-16%

Types of transportation	Reference	$15 Fee	$25 Fee	$35 Fee
Light-duty Vehicles	-22%	-26%	-28%	-29%
Freight Trucks	-2%	-6%	-9%	-11%
Air Travel	36%	35%	34%	33%
All Other	-1%	-4%	-5%	-6%
Total	-8%	-12%	-14%	-16%

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Prices

Electricity prices

In the Reference case, electricity prices (in real 2019 dollars) remain relatively stable and are slightly lower in 2050 than in 2020 (Table 5). In the carbon fee cases, they rise until 2030 and remain relatively stable afterwards. In 2050, the average electricity price for all sectors is 12% higher than the Reference case in the $15 Fee case, 17% higher in the $25 Fee case, and 20% higher in the $35 Fee case.

Table 5. Electricity prices by sectors and carbon fee cases

(cents per kilowatthour)

Case/sector	2020	2025	2030	2035	2040	2045	2050
Reference							
Residential	12.40	12.86	13.06	13.00	12.84	12.72	12.52
Commercial	10.31	10.39	10.38	10.18	9.98	9.83	9.65
Industrial	6.74	6.58	6.57	6.48	6.38	6.30	6.27
Transportation	11.57	12.33	12.52	12.48	12.15	11.83	11.53
Average to all sectors	10.21	10.32	10.37	10.26	10.13	10.03	9.90
$15 Fee							
Residential	12.42	13.92	13.92	13.94	13.84	13.80	13.84
Commercial	10.33	11.37	11.17	11.06	10.83	10.73	10.69
Industrial	6.74	7.52	7.33	7.30	7.26	7.24	7.32
Transportation	11.59	13.28	13.39	13.43	13.34	13.23	13.14
Average to all sectors	10.22	11.32	11.18	11.16	11.07	11.04	11.08
$25 Fee							
Residential	12.42	14.30	14.16	14.21	14.31	14.33	14.38
Commercial	10.33	11.73	11.38	11.22	11.23	11.21	11.22
Industrial	6.74	7.83	7.54	7.54	7.63	7.64	7.75
Transportation	11.59	13.65	13.66	13.94	13.86	13.78	13.67
Average to all sectors	10.22	11.67	11.40	11.39	11.49	11.52	11.60
$35 Fee							
Residential	12.40	14.72	14.51	14.58	14.69	14.74	14.71
Commercial	10.31	12.11	11.69	11.55	11.60	11.62	11.52
Industrial	6.73	8.17	7.85	7.85	7.93	7.97	8.04
Transportation	11.57	14.04	14.05	14.31	14.28	14.12	13.97
Average to all sectors	10.21	12.06	11.73	11.74	11.86	11.92	11.91

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Fossil fuel prices

The carbon fees have their greatest effect on coal prices (including fees), which are more than 700% higher in the $35 fee case in 2050 (Table 6). Prices are primarily affected by the carbon fee itself because the demand for coal is lowered in the carbon fee cases, which by itself could lower prices. The carbon fees have their second greatest effect on natural gas prices. Natural gas prices in the carbon fee cases are affected by a combination of the fee and the sustained demand for natural gas as coal consumption declines, especially in the early part of the projection period.

Table 6. Selected national average fossil fuel product prices by Reference and carbon fee cases (2019$ per million British thermal units)

Case/Fuel	2020	2025	2030	2035	2040	2045	2050
Reference							
Motor Gasoline	22	22	23	25	26	27	29
Jet Fuel	14	15	17	18	19	21	22
Distillate	21	22	23	24	25	26	27
Natural gas	5	5	6	6	6	6	6
Coal	2	2	2	2	2	2	2
$15 Fee							
Motor Gasoline	22	23	25	26	28	30	33
Jet Fuel	14	16	18	20	22	24	26
Distillate	21	23	24	26	28	30	32
Natural gas	5	6	7	7	8	8	9
Coal	2	4	4	5	6	7	9
$25 Fee							
Motor Gasoline	22	24	26	28	30	32	36
Jet Fuel	14	17	19	21	24	27	29
Distillate	21	24	25	28	30	32	35
Natural gas	5	7	8	8	9	10	11
Coal	2	5	6	7	9	10	13
$35 Fee							
Motor Gasoline	22	25	27	29	32	34	38
Jet Fuel	14	18	20	23	26	29	32
Distillate	21	25	26	29	31	35	38
Natural gas	5	8	8	9	10	12	13
Coal	2	6	8	9	11	14	17

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Table 7 indicates the effect of carbon fees on the operating costs of coal and natural gas generators. The carbon fees increase the costs of all fossil fuel generation, but because natural gas is less carbon intensive than coal, it changes the competitiveness of coal versus natural gas in meeting electric load. In the Reference case, the operating cost of coal generators is less than that of natural gas combined-cycle generators after 2021. However, in the carbon fee cases, once the fee is imposed, the opposite occurs. The operating cost of natural gas generators is less than that of coal generators through the projection period. As soon as the carbon fee is imposed, the advantage in operating costs of natural gas generators versus coal generators contributes to the near-term switch from coal to natural gas generation. Eventually, natural gas loses share to renewable generation. Higher generation costs contribute to an increase in electricity prices as reflected in Table 8.

Table 7. Effect of carbon fee on the operating costs for coal and gas generators

Case/fuel		2020	2021	2030	2040	2050
		2019 dollars per megawatthour [1]				
Reference						
	Gas	20.5	21.6	25.8	26.5	28.0
	Coal	21.3	20.8	19.2	19.1	19.1
	Difference	(0.7)	0.7	6.7	7.4	8.9
$15 Fee						
	Gas	20.7	29.6	34.5	39.2	48.9
	Coal	21.4	35.4	41.4	59.2	93.9
	Difference	(0.7)	(5.9)	(6.9)	(20.0)	(44.9)
$25 Fee						
	Gas	20.7	34.8	39.4	48.0	65.3
	Coal	21.4	46.9	58.3	92.1	142.5
	Difference	(0.7)	(12.1)	(18.9)	(44.1)	(77.2)
$35 Fee						
	Gas	20.7	38.9	44.6	58.1	82.0
	Coal	21.4	56.9	74.9	123.4	189.9
	Difference	(0.7)	(18.0)	(30.3)	(65.3)	(107.9)

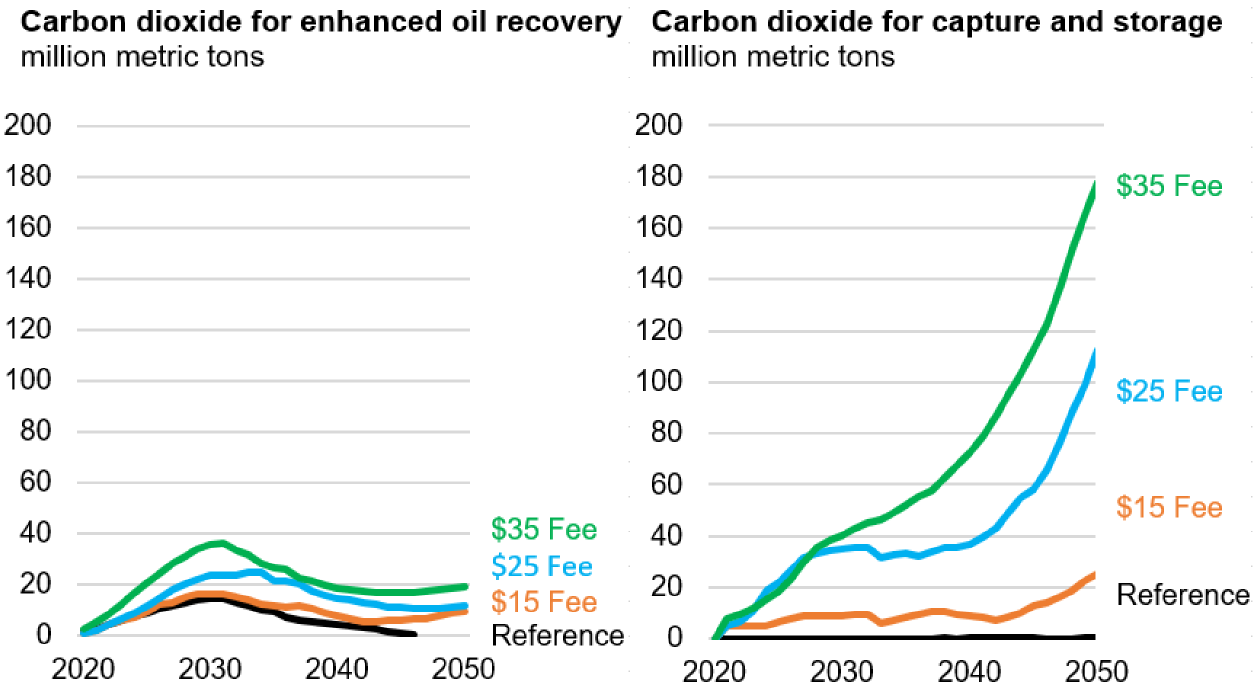
(1) (delivered fuel cost in dollars per million British thermal units) x (average heat rate for coal and combined-cycle natural gas plants), excluding operations and maintenance costs

Carbon capture, utilization, and storage

In the carbon fee cases, additional CO2 is mitigated with carbon capture, utilization, and storage that removes CO2 after combustion (Figure 18). The CO2 is then liquefied and transported through pipelines to be used or stored. In the Reference case, 0.21 MMmt of CO2 are captured in 2050. In the $15 Fee case, $25 Fee case, and $35 Fee case, 26 MMmt of CO2, 112 MMmt of CO2, and 178 MMmt of CO2 are captured annually by 2050, respectively.

In the Reference case, during the peak years in the early 2030s, about 15 MMmt of CO2 used for enhanced oil recovery (EOR) comes from anthropogenic sources (caused by human activity rather than derived from natural sources)—about equal amounts from ethanol production and natural gas processing. Very little CO2 for EOR comes from the electric power sector. Carbon fees cause this to change, with 36 MMmt of CO2 coming from the power sector at the peak in 2031 in the $35 Fee case, representing 84% of the total purchased anthropogenic CO2 sources. In the Reference case, domestic oil production begins to plateau in the 2030s, and demand for CO2 for EOR generally declines. However, in the fee cases, CO2 for EOR from these sources rises as the fees rise.

Figure 18. The fee cases increase the amount of carbon dioxide captured, used, and stored

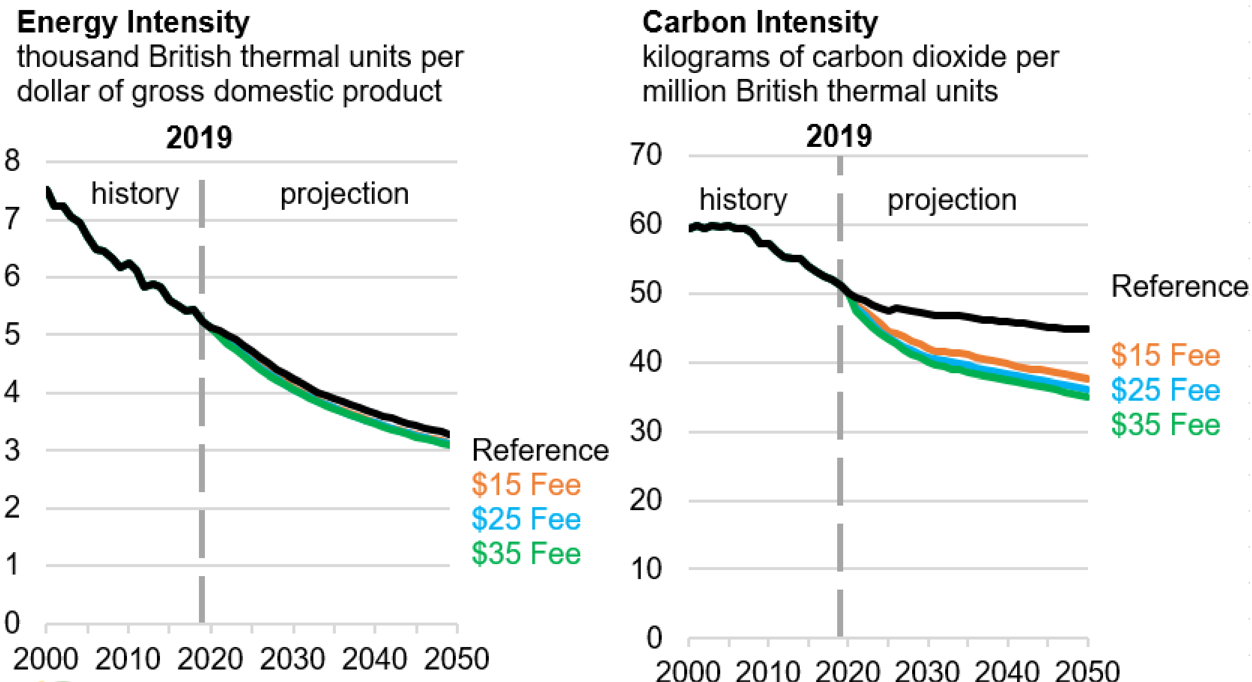


Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Energy and carbon intensity

Both the energy intensity and carbon intensity of the U.S. economy are affected by the carbon fees (Figure 19). The carbon intensity (kg CO2/Btu) declines because the carbon fee encourages substitution of less carbon-intensive fuels in place of more carbon-intensive ones where possible. The energy intensity (Btu/GDP) declines because energy prices rise with carbon fees, reducing demand for energy products and causing increases in energy efficiency.

Figure 19. Energy and carbon intensity for all cases



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

No Affordable Clean Energy (ACE) Rule

The AEO2020 Reference case includes the ACE rule, which was issued by the U.S. Environmental Protection Agency (EPA) in June 2019 to establish guidelines for states developing plans to limit carbon dioxide (CO2) emissions at existing coal-fired power plants.[5] The rule defines the "best system of emission reduction" for existing plants as onsite projects that lead to heat rate efficiency improvements. AEO2020 reflects this program in its projections by requiring all coal-fired plants with the potential to improve plant heat rates to undertake these projects or retire by 2025, using data from a 2015 analysis conducted for EIA of potential plant heat rate improvement options.[6] The year 2025 follows the approach adopted in EPA's ACE rule Regulatory Effect Analysis that estimates the schedule for when the standards of performance under the final rule might be implemented. The rule gives states some flexibility in the timing of plan submission, which will be followed by an EPA review process, leading to uncertainty surrounding the final date when all states are in compliance.

Some examples of the uncertainly surrounding the implementation of EPA rules include the Clean Power Plan, which was issued in 2015 but was challenged in court. Its implementation was stayed by the U.S. Supreme Court in 2016 and was eventually repealed by executive order in 2017. As a result, to address potential uncertainty in our AEO2020 modeling, EIA chose to consider a case where the ACE rule is not implemented.

Methodology

The No ACE Rule case assumes that the existing ACE rule is not implemented and that all coal-fired power plants continue to operate at their current efficiency levels throughout the projection period. This case illustrates the effect the ACE rule has in the AEO2020 Reference case.

Results

In the No ACE Rule case, 9 GW less coal-fired capacity is retired in 2025 than in the Reference case, and 6 GW less is retired by 2050 (Figure 20). This result has a larger effect in 2025–39, with 2%–3% more coal-fired generation in the No ACE Rule case compared with the Reference case. During 2040–50, less-efficient coal-fired capacity is either dispatched less or remains in service to satisfy reserve requirements rather than to meet energy needs during that period, and the No ACE Rule case and Reference case have similar coal-fired generation.

However, coal consumption averages 5% more than in the Reference case from 2040 to 2050 because, without the ACE-required heat rate improvements, generating coal-fired plants have lower average efficiencies in the No ACE Rule case. More coal consumption in the No ACE Rule case also affects CO2

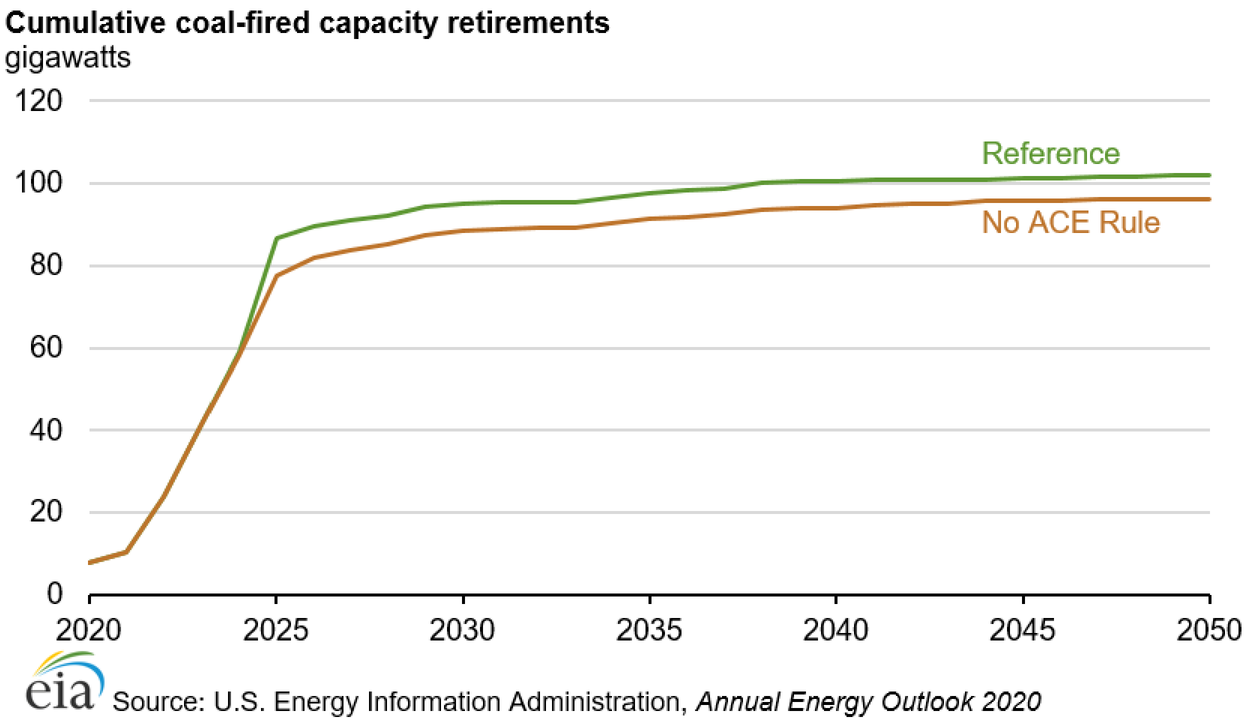
[5] Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations, Environmental Protection Agency, Federal Register, Vol. 84, No. 130 (July 8, 2019).

[6] Analysis of Heat Rate Improvement Potential at Coal-Fired Power Plants, May 2015, Leidos, Inc.

emissions from the power sector, which are 5% more than the Reference case levels in 2025 and remain 2% more than in the Reference case in 2050.

The slightly higher level of coal-fired electricity generation in the middle years of the projection period in the No ACE Rule case is offset primarily by lower renewables electricity generation, but the overall generation mix is largely unchanged over the long run as a similar amount of renewable capacity comes online by 2050 in both cases. With additional coal-fired capacity remaining online in the No ACE Rule case, 9 GW fewer new natural gas-fired capacity additions are projected through 2050 to meet reserves. Because the increase in fuel costs from slightly higher levels of coal consumption is offset by lower levels of capital investment, electricity prices are unchanged. Fewer coal plant retrofits are required, and less new natural gas-fired capacity is needed.

Figure 20. Cumulative coal-fired capacity retirements in two cases



Utility Rate Structure

Distributed generation technologies such as solar photovoltaics (PV) are increasingly used to reduce electricity purchases for buildings from the grid. As more homes incorporate solar PV, electric utilities and state utility commissions continually evaluate ways to equitably compensate solar PV system owners for generation. Changing compensation rates lead to growing uncertainty about future solar PV adoption.

The alternative utility rate structure cases incorporate *wholesale* or *marginal* electricity prices as compensation for *all* residential solar PV generation, whether consumed onsite or sold back to the grid, in place of the assumptions used in the AEO2020 Reference case and core side cases that compensate all residential PV generation at *retail* electricity rates. EIA does not have an opinion on policies to compensate PV generation. These alternative assumptions provide boundary cases that examine how the uncertainty in net metering policy might affect solar PV adoption across the United States compared with higher or lower economic growth, renewable equipment costs, or oil and gas supply.

Distributed PV systems are typically roof-mounted and operate behind the meter, which could reduce utility investment in transmission and distribution infrastructure when compared with centrally deploying equivalent solar PV assets. In the AEO2020 Reference case, residential sector solar PV capacity increases by an average of 6.1% per year through 2050. Adoption grows as installed equipment costs[7] decline and the federal investment tax credit (ITC)—scheduled to phase down through 2022—further reduces costs.

Much of the electricity generation from residential PV systems is consumed onsite, avoiding the retail purchase of electricity. Generation that is not used onsite is sold back to the electric utility. Most states[8] have net metering utility tariffs that allow residential customers, within the billing period, to reduce the billed volume of electricity supplied by the grid by the volume of electricity that the customer sold back to the grid during times that self-generation exceeded consumption. The solar PV generation is usually reimbursed at the same retail electricity rate that consumers would be charged to purchase electricity from the grid.

In some regions, including those with higher levels of variable renewable energy capacity, utilities reimburse consumers for excess electricity sold to the grid at rates that value solar PV generation closer to the wholesale price of electricity instead of the retail rate, in part, to manage the amount of variable energy capacity added to the grid. Wholesale electricity rates—the prices at which electricity is traded on regional electricity markets—are significantly lower than retail electricity rates because they do not account for transmission or distribution costs. Reimbursing at the wholesale electricity rate can lead to longer payback periods for residential solar PV equipment than if consumers received compensation at the retail electricity rate.

How utilities compensate solar PV generation has changed in some states in recent years. In 2019, Maine switched from a policy of *gross metering*—in which all generation, whether used onsite or sold

[7] The Assumptions to AEO2020 summarize residential solar PV costs used in all cases except the Low Renewables Cost and High Renewables Cost cases. The former assumes 40% lower solar PV installed equipment costs—also known as overnight capital costs—than the Reference case by 2050, while the latter holds PV costs at the 2019 level through 2050.

[8] The Database of State Incentives for Renewables and Efficiency includes the latest state-level distributed generation policies.

back to the grid, is compensated below the retail price of electricity—back to net metering. New York grandfathers residential systems built before 2020 into net metering agreements; however, new systems will fall under Value of Distributed Energy Resources (VDER) compensation. In Arizona, new solar PV generation is valued at a rate below retail electricity that is based on utility-scale solar prices.

Methodology

The alternative utility rate structure cases consist of seven individual cases:

- Reference with Wholesale PV Rate
- High Economic Growth with Wholesale PV Rate
- Low Economic Growth with Wholesale PV Rate
- High Oil and Gas Supply with Wholesale PV Rate
- Low Oil and Gas Supply with Wholesale PV Rate
- High Renewables Cost with Wholesale PV Rate
- Low Renewables Cost with Wholesale PV Rate

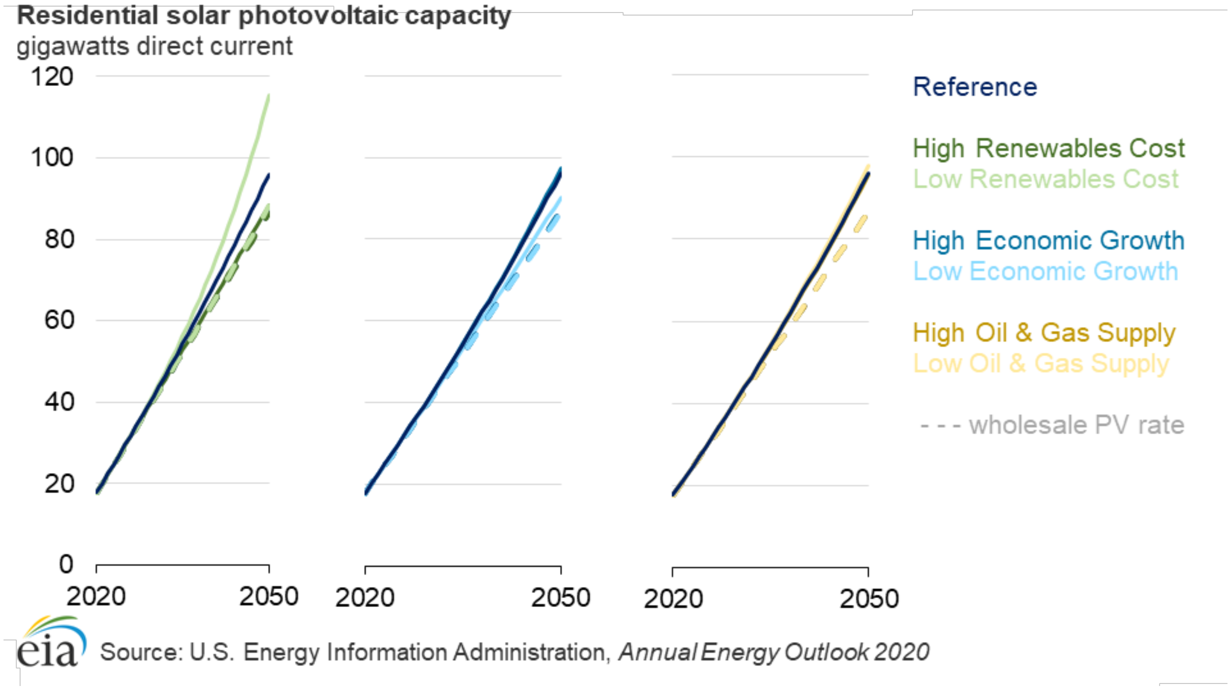
These seven cases are modeled by varying the price at which residential solar PV generation is compensated in the AEO2020 Reference, High Economic Growth, Low Economic Growth, High Oil and Gas Supply, Low Oil and Gas Supply, High Renewables Cost, and Low Renewables Cost cases, respectively. That is, all residential solar PV generation from 2020 onward is valued at the wholesale rate rather than the residential retail price of electricity.

Electricity rates continue to vary by census division as in all other cases. Assumption changes were made only to the residential model, so any variation in other sectors—including utility sector projections—in the Reference case and side cases with the alternative utility rate structure case assumptions are a result of the changes in residential solar PV adoption.

Results

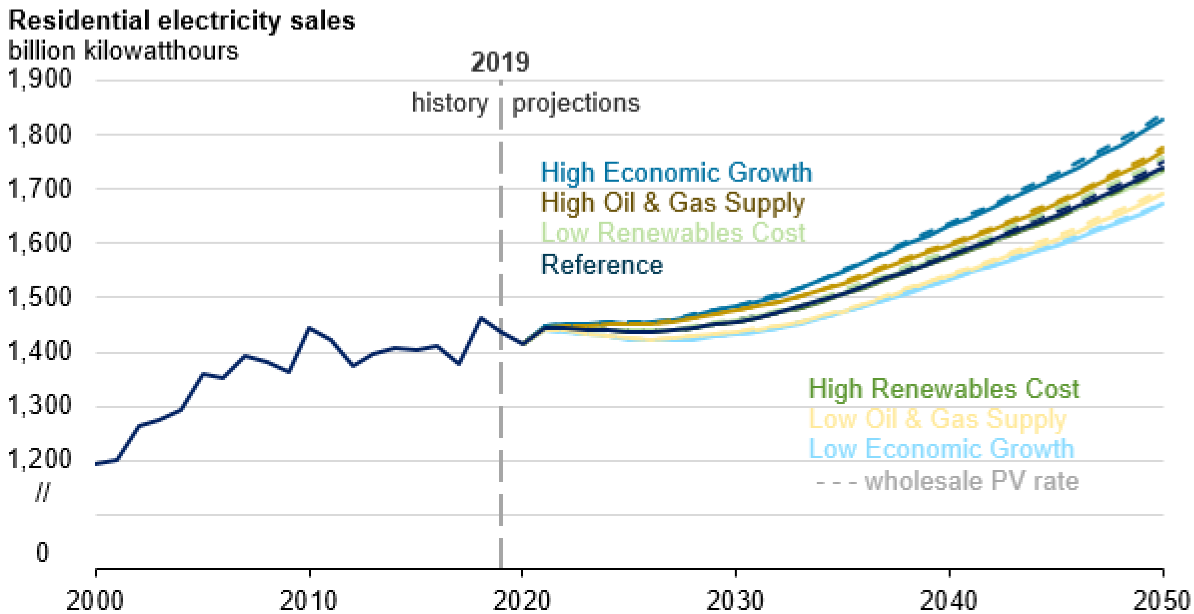
Because wholesale PV rates are generally lower than retail rates, residential solar PV capacity decreases in all alternative utility rate structure cases. As a result, the Reference with Wholesale PV Rate case shows 10% less capacity when compared with the Reference case in 2050 (Figure 21). Of all the cases examined in this analysis, the Low Renewables Cost case—where installed equipment costs are 40% lower than in the Reference case by 2050—shows the greatest difference in residential solar PV capacity when the wholesale PV rate case assumptions are applied. There is 24% less residential solar PV capacity in 2050 in the Low Renewables Cost with Wholesale PV Rate case than in the Low Renewables Cost case (with retail rate compensation). In fact, there is less residential solar PV capacity in 2050 in the Low Renewables Cost with Wholesale PV Rate case than there is in the Reference case, which includes retail rate compensation. For residential solar PV, the change in the utility rate structure has a greater impact than a 40% decrease in the cost by 2050.

Figure 21. Residential solar photovoltaic capacity from select alternative cases, 2020–2050



The wholesale utility rate structure assumption causes residential solar PV capacity to decrease and sector electricity sales to increase when compared with cases using retail PV rates (Figure 22). However, differences between the AEO2020 side cases have a greater effect on residential electricity sales than the utility rate structure does. These differences include the level of economic growth in the United States, which drives disposable income and the number of new housing units throughout the projection period; the cost of renewables in all sectors; and the supply of oil and gas, which affects natural gas prices. The effects of the alternative utility rate structure assumptions vary from 0.1% higher retail sales in 2050 in the High Renewables Cost with Wholesale PV Rate case (compared with the corresponding retail rate case) to 1.5% higher in 2050 in the Low Renewables Cost with Wholesale PV Rate case (compared with the corresponding retail rate case). The differences are determined by the changes in generation based on the residential solar PV capacity shown in Figure 21. By comparison, residential electricity sales in the AEO2020 High Economic Growth and Low Economic Growth cases are 5% higher and 4% lower, respectively, in 2050 than in the Reference case.

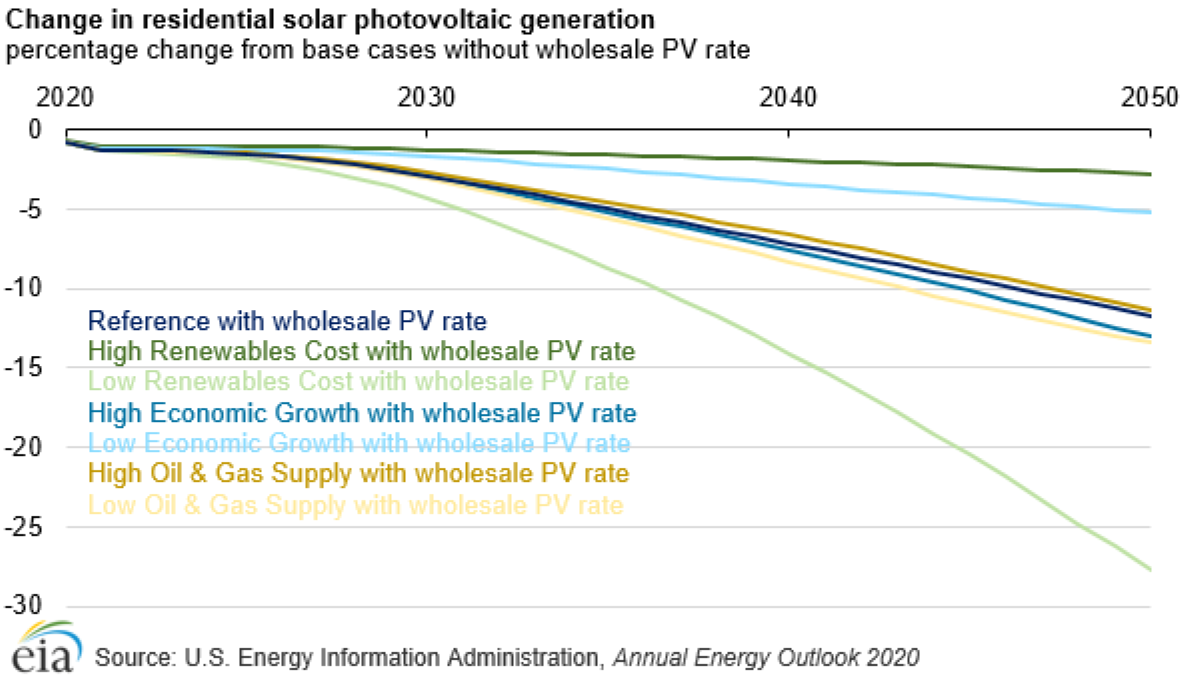
Figure 22. Residential electricity sales in Reference case and select alternative cases, 2000–2050



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*

Residential solar PV generation with wholesale PV rate assumptions decreases when compared with cases using retail PV rates (Figure 23). Changing the amount of residential solar PV by switching rate structures can also impact the deployment of utility-scale solar. The amount, and even the direction, of change in utility-scale solar PV generation varies among the alternative utility rate structure cases. The change in utility-scale solar does not always offset the decrease in residential solar. Sometimes, utility-scale solar generation even decreases, in part, because increased demand for electricity sales from the grid created by less residential generation can be met by increases in both non-renewable utility generation as well as utility solar PV, and the relative competitiveness of these non-renewable resources varies across the AEO2020 side cases. Because the amount of utility-scale solar PV is so much greater than residential sector solar PV, changes resulting from switching the utility-rate compensation have a much larger relative impact on residential solar PV than they do on utility-scale solar PV. For example, although residential PV generation is 28% less in 2050 in the Low Renewables Cost with Wholesale PV case than it is in the corresponding retail rate case, total power sector generation increases by only 0.9% in 2050 in the Low Renewables Cost with Wholesale PV Rate case than it does in the corresponding retail rate case.

Figure 23. Change in residential solar photovoltaic generation in alternative cases, 2020–2050



Solar PV growth is sensitive to electricity prices; however, the effect of wholesale PV rate compensation on residential average retail electricity prices is minimal when compared with cases assuming retail rates. Throughout the projection period, the Low Oil and Gas Supply and High Oil and Gas Supply cases yield the greatest average differences in residential electricity prices from the AEO2020 Reference case, with 4.7% lower and 9.7% higher, respectively, in 2050. Assuming wholesale compensation of residential solar PV, residential retail electricity prices in 2050 are 0.3% higher in the Low Oil and Gas Supply with Wholesale PV Rate case and are 0.5% lower in the High Oil and Gas Supply with Wholesale PV Rate case as compared with retail compensation in the Low Oil and Gas Supply case and High Oil and Gas Supply case, respectively. Although the impact on prices is minimal, the impact on electricity costs for owners of existing solar PV systems could be significant under a change in compensation.

Appendix 1. Alternative policy scenario case descriptions

Section	Case name	Description
50% Carbon-Free Generation	50% Carbon-Free Generation case	States achieve a minimum 50% of electricity sales by 2050 using zero- or low-carbon generating technologies
	Renewable Portfolio Standard (RPS) Sunset case	States with existing RPS policies terminate their programs in 2020, and no new RPS or carbon-free generation policies are enacted
Carbon Fees	$15 Fee case	Imposes an economy-wide carbon fee starting at $15 per metric ton of carbon dioxide in 2021 and rises by 5% (real) per year
	$25 Fee case	Imposes an economy-wide carbon fee starting at $25 per metric ton of carbon dioxide in 2021 and rises by 5% (real) per year
	$35 Fee case	Imposes an economy-wide carbon fee starting at $35 per metric ton of carbon dioxide in 2021 and rises by 5% (real) per year
No Affordable Clean Energy (ACE) Rule	No ACE case	Removes the implementation of ACE
Utility Rate Structure	Reference with Wholesale Photovoltaic (PV) Rate case	Compensates residential solar PV generation from 2020 onward at the wholesale PV rate
	High Economic Growth with Wholesale PV Rate case	Compensates residential solar PV generation from 2020 onward at the wholesale PV rate with AEO2020 High Economic Growth case assumptions
	Low Economic Growth with Wholesale PV Rate case	Compensates residential solar PV generation from 2020 onward at the wholesale PV rate with AEO2020 Low Economic Growth case assumptions
	High Oil and Gas Supply with Wholesale PV Rate case	Compensates residential solar PV generation from 2020 onward at the wholesale PV rate with AEO2020 High Oil and Gas Supply case assumptions
	Low Oil and Gas Supply with Wholesale PV Rate case	Compensates residential solar PV generation from 2020 onward at the wholesale PV rate with AEO2020 Low Oil and Gas Supply case assumptions
	High Renewables Cost with Wholesale PV Rate case	Compensates residential solar PV generation from 2020 onward at the wholesale PV rate with AEO2020 High Renewables Cost case assumptions
	Low Renewables Cost with Wholesale PV Rate case	Compensates residential solar PV generation from 2020 onward at the wholesale PV rate with AEO2020 Low Renewables Cost case assumptions

Appendix 2. Renewable Portfolio Standard requirements in the Reference case and 50% Carbon-Free Generation case

State[1]	Reference case target	50% Carbon-Free Generation by 2050	Reference case qualifying technologies	50% Carbon-Free Generation qualifying technologies added
AZ	15% by 2025	50% by 2050	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	Nuclear, carbon capture and sequestration
CA	60% electricity generation by 2030, 100% carbon-free by 2045	Maintains Reference case path	Geothermal electric, solar thermal electric, solar photovoltaics, wind biomass, municipal solid waste, landfill gas, hydroelectric Carbon-free includes nuclear, carbon capture and sequestration	No additional technologies
CO	30% by 2020 for investor-owned utilities, 20% by 2020 for large electric cooperatives, 10% by 2020 for other cooperatives and municipal utilities serving more than 40,000 customers	50% by 2050, for all utilities	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells	Nuclear, carbon capture and sequestration
CT	48% by 2030 (44% renewables, 4% efficiency and combined heat and power)	50% by 2050	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	Nuclear, carbon capture and sequestration
DE	25% by 2026	50% by 2050	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	Nuclear, carbon capture and sequestration
DC	100% by 2040	Maintains Reference case path	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	No additional technologies
IL	25% by 2026 (3,000 megawatts [MW] solar and 1,300 MW wind)	50% by 2050	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, offshore wind	Nuclear, carbon capture and sequestration
IA	105 MW of eligible renewable resources	50% by 2050, starting in 2025	Solar thermal, solar PV, wind, biomass, hydroelectric, municipal solid waste, landfill gas, offshore wind	Nuclear, carbon capture and sequestration, geothermal
MA	35% by 2030 (and an additional 1% per year thereafter)	Maintains Reference case path. MA path ends at 50% by 2050	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	No additional technologies
MD	50% by 2030	Maintains reference case path	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	No additional technologies

State[1]	Reference case target	50% Carbon-Free Generation by 2050	Reference case qualifying technologies	50% Carbon-Free Generation qualifying technologies added
ME	100% by 2050	Maintains Reference case path	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	No additional technologies
MI	15% by 2021, with specific new capacity goals for utilities that serve more than one million customers	50% by 2050 for all utilities regardless of size	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, offshore wind	Nuclear, carbon capture and sequestration
MN	31.5% by 2020 (Xcel), 26.5% by 2025 (other investor-owned utilities), or 25% by 2025 (other utilities)	50% by 2050 for all utilities	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, offshore wind	Nuclear, carbon capture and sequestration
MO	15% by 2021	50% by 2050, starting in 2025	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	Nuclear, carbon capture and sequestration
MT	15% by 2015	50% by 2050, starting in 2025	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	Nuclear, carbon capture and sequestration
NC	12.5% by 2021 for investor-owned utilities, 10% by 2018 for municipal and cooperative utilities	50% by 2050, starting in 2025, applies to all utilities	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, offshore wind	Nuclear, carbon capture and sequestration
NH	24.8% by 2025	50% by 2050	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	Nuclear, carbon capture and sequestration
NJ	50% by 2030 with the solar carve-out reaching 5.1% in 2021 before gradually decreasing to 1.1% by 2033	Maintains Reference case path	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	No additional technologies
NM	80% renewable generation by 2040, 100% carbon-free by 2045	Maintains Reference case path	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind Carbon-free includes nuclear	No additional technologies
NV	50% renewable generation by 2030, 100% carbon-free by 2050	Maintains Reference case path	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind Carbon-free includes nuclear	No additional technologies
NY	70% renewable generation by 2030, 100% carbon-free by 2040.	Maintains Reference case path	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind Carbon-free includes nuclear	No additional technologies

State[1]	Reference case target	50% Carbon-Free Generation by 2050	Reference case qualifying technologies	50% Carbon-Free Generation qualifying technologies added
OH	8.5% renewable energy resources by 2026	50% by 2050	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	Nuclear, carbon capture and sequestration
OR	50% by 2040	Maintains Reference case path	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, offshore wind	No additional technologies
PA	18% by 2020	50% by 2050, starting in 2025	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	Nuclear, carbon capture and sequestration
RI	38.5% by 2035	50% by 2050, starting in 2035	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	Nuclear, carbon capture and sequestration
TX	5,880 MW by 2015	50% by 2050, starting in 2025	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, offshore wind	Nuclear, carbon capture and sequestration
VT	75% by 2032	Maintains Reference case path	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	No additional technologies
WA	100% carbon-free by 2045	Maintains Reference case path	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	No additional technologies
WI	10% by 2015	50% by 2050, starting in 2025	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, fuel cells, offshore wind	Nuclear, carbon capture and sequestration
All other states[2]	Several states included here have current renewable portfolio goals, which are non-binding and therefore not modeled in the Reference case	50% by 2050, starting in 2025	NA	Geothermal electric, solar thermal, solar PV, wind, biomass, hydroelectric, landfill gas, offshore wind, nuclear, carbon capture and sequestration

[1] Although Hawaii has a 100% renewable generation by 2045 Renewable Portfolio Standard that is implicitly accounted for in previous work, the generation in Alaska and Hawaii are not included in this analysis as the generation mix from these states is determined outside of the NEMS model because of the unique electricity supply markets in these states.

[2]*All other states* includes AL, AR, FL, GA, ID, IN, KS, KY, LA, MS, ND, NE, OK, SC, SD, TN, UT, VA, WV, WY