Assumptions to the Annual Energy Outlook 2023: Renewable Fuels Module

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Renewable Fuels Module

The National Energy Modeling System's (NEMS) Renewable Fuels Module (RFM) provides supply and technology inputs for natural resources. We use these inputs to project new utility-scale U.S. electric-generating capacity that uses renewable energy resources. The RFM has six submodules that represent various renewable energy resources:

- Biomass
- Geothermal
- Conventional hydroelectricity
- Landfill gas (LFG)
- Solar (thermal and photovoltaic)
- Wind (offshore and onshore)[1]

The submodules of the RFM interact primarily with the Electricity Market Module (EMM) within NEMS. The EMM represents electricity capacity planning, dispatching, and pricing. Because the EMM is highly integrated with the RFM, the final outputs (consumption and market penetration over time) for renewable energy technologies depend largely on the EMM. The RFM also interacts with the Renewable Storage Submodule (REStore) to estimate not only the impact of energy storage on dispatching electricity but also the hourly capacity factors of intermittent renewable technologies for capacity credit calculations in each of the modeled electricity regions.

Because some types of biomass fuel can be used for either electricity generation or for liquid fuels production (such as ethanol), the RFM also interacts with the Liquid Fuels Market Module (LFMM). The LFMM represents some additional biomass feedstocks that are used primarily for liquid fuels production.

We developed projections for residential and commercial grid-connected photovoltaic systems in the end-use demand modules, and they are not included in the RFM; more details are available in the Commercial Demand Module (CDM) and Residential Demand Module (RDM) sections of this report. Descriptions of biomass energy production in industrial settings, such as the pulp and paper industries, are in the Industrial Demand Module (IDM) section of the report.

Technologies

Electric power generation

The RFM considers only grid-connected, central-station electric-generating systems that use renewable electricity sources:

- Biomass
- Geothermal
- Conventional hydroelectricity
- LFG
- Solar (thermal and photovoltaic)
- Wind (offshore and onshore)

Each submodule provides specific data or estimates that characterize the respective renewable source. The EMM evaluates technologies, including the build and dispatch decisions. Table 2 in the EMM documentation summarizes the technology cost and performance values.

Nonelectric renewable energy uses

In addition to projections for renewable energy used in central-station electricity generation, the *Annual Energy Outlook 2023* (AEO2023) projects nonelectric renewable energy consumption for:

- Wood burning for industrial and residential space heating
- Solar residential and commercial hot water heating
- Biofuels blending for transportation fuels
- Residential and commercial geothermal (ground-source) heat pumps

Assumptions for these projections are in the Residential Demand Module, Commercial Demand Module, Industrial Demand Module, and Liquid Fuels Market Module reports. The projections do not include additional, minor renewable energy applications that occur outside of energy markets, such as:

- Direct solar thermal industrial applications
- Direct lighting
- Off-grid electricity generation
- Heat from geothermal resources used directly (for example, district heating and greenhouses)

Capital costs

The EMM assumptions documentation describes the methodology we used to determine initial capital costs, which are based on cost estimates developed in a 2020 report prepared by Sargent & Lundy. The costs are adjusted for assumed technology learning from any capacity added since 2019 and for general inflation and cost escalation for key commodity inputs.[2] These cost estimates used a consistent estimation methodology across all technologies to develop cost and performance characteristics for technologies that we wanted to consider in the EMM. We did not use the costs the consultant developed for geothermal and hydro plants because we used previously developed site-specific costs for those technologies. We also did not update costs for distributed generation plants in the electric power sector based on the consultant report, and instead, the assumptions remained the same as in previous AEOs. We updated inputs for all other technologies listed in Table 2 in the EMM chapter of this assumptions report.

Except where noted, the overnight costs shown in Table 2 in the EMM Assumptions represent the estimated cost of building a plant before adjusting for regional cost factors. Overnight costs exclude interest expenses during plant construction and development. Although not presented separately, as in previous AEOs, the base overnight costs include project contingency, which accounts for undefined project scope and pricing uncertainty and for owners' cost components. Technologies with limited commercial experience may include a technological optimism factor to account for the tendency during technology research and development to underestimate the full engineering and development costs for new technologies or to represent first-of-a-kind costs needed to develop the infrastructure required to support future development. A cost-adjustment factor, based on the producer price index for metals and metal products, makes the overnight capital costs in the future to fall if this index drops or to rise if it increases.

Several factors affect capital costs for renewable fuels technologies. For geothermal, hydroelectric, and wind resources, we assume capital costs to develop the resources depend on the quality, accessibility, or other site-specific factors in the areas with usable resources. These factors can include:

- Additional costs associated with reduced resource quality
- The need to build or upgrade transmission capacity from remote resource areas to load centers
- Local impediments to permitting, equipment transport, and construction in good resource areas
- Inadequate infrastructure
- Rough terrain

To accommodate unexpected demand growth as a result of a rapid nationwide buildup in a single year, we use short-term cost adjustment factors to increase technology capital costs, reflecting limitations on the infrastructure (for example, limits on manufacturing, resource assessment, and construction expertise). These factors, which we apply to all new electric-generating capacity, are a function of past production rates and are further described in *The Electricity Market Module of the National Energy Modeling System: Model Documentation 2022*.

We also assume costs associated with construction commodities, such as bulk metals and concrete, affect all new capacity types. Although a generic construction cost index is not available within NEMS, capital costs are specifically linked to the projections for the metals producer-price index found in the Macroeconomic Activity Module of NEMS. Independent of the other two factors, we assume capital costs for all electric-generating technologies, including renewable technologies, decline because of growth in installed capacity for each technology. For a description of NEMS algorithms that reduce generating technologies' capital costs as more units enter service (learning), see *Technological optimism and learning* in the EMM assumptions.

A detailed description of the RFM is available in *Renewable Fuels Module of the National Energy Modeling System: Model Documentation 2022*, DOE/EIA-M069 (2022) Washington, DC, 2022.

Solar Submodule

Background

The RFM Solar Submodule primarily sets the capacity factors for the solar technologies and tracks available solar resources. It tracks solar capacity by resource quality within a region and moves to the next best solar resource when one category is exhausted. Solar resource data on the amount and quality of solar irradiance per EMM region come from the National Renewable Energy Laboratory (NREL).[3] Solar technologies include both solar thermal (also referred to as concentrating solar power, or CSP) and photovoltaic (PV). Since AEO2021, we have included a combined solar PV and battery-storage hybrid system as a generating technology option for capacity expansion.

The Solar Submodule passes available solar capacity and its associated capacity factors to the EMM for capacity planning and dispatch decisions. Based on these characteristics, the EMM determines how much power generation capacity is available from solar energy.

Assumptions

Technology

- The RFM includes only grid-connected utility-scale generation. The CDM and RDM include projections for end-use solar PV generation.
- CSP cost estimation is based on a 100-megawatt (MW) central-receiver tower without integrated energy storage. CSP is available only in the western regions where the arid atmospheric conditions result in the most cost-effective capture of direct sunlight.
- The solar PV technology represented includes a 150 MW AC (alternating current) array of flat-plate PV modules with single-axis tracking. All EMM regions assume that solar PV is available.
- The solar PV plus battery storage hybrid technology (PV-battery hybrid) includes the same 150 MW AC array as the PV with single-axis tracking technology. It also includes a 50-MW capacity, 200-megawatthour (four-hour duration) lithium-ion battery storage system. The PV-battery hybrid system is DC (direct current) tightly coupled, meaning both the PV and battery share a single DC-to-AC inverter and the battery can only charge using energy from the solar PV, not the grid. The PV-battery hybrid uses the same constant generation profile as the standalone PV technology, but the battery can store additional available PV energy, which he inverter would otherwise clip in a standalone PV system. We created this additional available energy profile for each EMM region by modeling a standalone PV system using NREL's System Advisor Model (SAM)[4] and then converting the clipped energy into 12x24 (average hour for each month of the year) capacity factor matrices as input for the RFM.

Cost

- For the single-axis tracking PV, PV-battery hybrid, and concentrated CSP systems used in NEMS, we based the cost data on a report by Sargent & Lundy called *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies,* published in 2020.
- The base cost in the Sargent & Lundy report for the PV-battery hybrid technology represents an AC-coupled PV-battery hybrid system, so the EMM assumes lower inverter costs proportional to the inverter capacity for the modeled DC-coupled system.
- Regional cost adjustments reflect location-based cost adjustments in each EMM region for PV technology, as provided by Sargent & Lundy.

Resources

- We reduce available solar resources by excluding all lands not suited for solar installations, such as land used for nonintrusive uses (national parks, wildlife refuges, etc.) or inherent incompatibility with existing land uses (such as urban areas, areas surrounding airports, and bodies of water).
- Most utility-scale solar PV systems are built with an array-to-inverter ratio (inverter loading ratio, or ILR) of between 1.2 and 1.3.[5, 6] Increased ILRs introduce solar clipping, where solar

generation is lost by exceeding the inverter's rated output power. Starting in AEO2022, we model solar PV capacity factors with an ILR of 1.30 by using the NREL's SAM to develop a more accurate time-of-day and seasonal output profile.

- We model CSP technology for regions where we assume the level of direct, normal insolation (the type required for that technology) is sufficient to make that technology commercially viable through the projection period.

Other

- For utility-scale solar PV projects (both stand-alone and hybrid systems), we assume a two-year construction lead time for start of construction to project completion. CSP has a three-year construction lead time.
- Existing capacity and planned capacity additions are based on our survey data from Form EIA-860, *Annual Electric Generator Report,* and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The module includes planned capacity additions under construction or with an expected completion date before the end of 2024, according to respondents' planned completion dates.

Wind Energy Submodule

Background

The Wind Energy Submodule represents both offshore and onshore wind resources at a hub height of 80 meters and categorizes annual average wind speeds based on a classification system developed at the Pacific Northwest National Laboratory. The RFM tracks wind capacity by resource quality and costs within a region and moves to the next best wind resource when one category is exhausted. Wind resource data on the amount and quality of wind per EMM region come from NREL.[7] The technological performance, cost, and other wind data used in NEMS are based on the Sargent & Lundy report, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, published in 2020.

The Wind Energy Submodule in the RFM passes the economically available wind capacity and its associated capacity factors to the EMM for capacity planning and dispatch decisions. Based on these characteristics, the EMM decides how much power generation capacity is available from wind energy.

Assumptions

Technology

- The RFM includes only grid-connected utility-scale wind generation. We include projections for distributed wind generation in the CDM and RDM.
- We calculate capacity factors for each wind class as a function of overall wind market growth. We implement an algorithm that increases the capacity factor within a wind class as more units enter service (learning). We assume the capacity factors for each wind class start at 48% and are limited to 55% for a Class 6 site. Despite increasing performance of the technology, the modeled capacity factors for new builds may decline within a given region as better wind resources are depleted and less desirable sites are used.

Cost

- In the Wind Energy Submodule, wind supply costs are affected by factors such as:
- Average wind speed
- Distance from existing transmission lines
- Resource degradation
- Transmission network upgrade costs
- Other market variables
- As with all technologies, wind technology capital costs decline with increasing market builds (learning). Because wind resources are limited within any region, capital costs may also increase in response to:

  - Declining natural resource quality, such as terrain slope, terrain roughness, terrain accessibility, wind turbulence, wind variability, or other natural resource factors as the best sites are used
  - Rising upgrade costs for existing local and network distribution and transmission lines to accommodate growing quantities of remote wind power
  - Changing market conditions, such as the increasing costs of alternative land uses, including aesthetic or environmental reasons

- Capital costs are left unchanged for the initial share, then increase by 10%, 25%, 50%, and finally 100% to represent the aggregation of these factors.

Resources

- We reduce available wind resources by excluding all windy lands not suited for wind turbines because of:
  - Excessive terrain slope (slope greater than 20%)
  - Reservation for nonintrusive uses (such as national parks and wildlife refuges)
  - Inherent incompatibility with existing land uses (such as urban areas or areas surrounding airports)
  - Insufficient contiguous windy land to support a viable wind plant (less than 5 square kilometers of windy land in a 100 square-kilometer area)
- The available resource base excludes half of the wind resources located on military reservations, U.S. Forest Service land, state forested land, and all non-ridge-crest forest areas to account for the uncertainty about siting projects at such locations. Appendix 4-E of *Renewable Fuels Module of the National Energy Modeling System: Model Documentation 2022* explains these assumptions in detail.
- Proportions of total wind resources in each category vary by EMM region. For all EMM regions combined, about 0.9% of windy land (106 gigawatts [GW] of 11,600 GW in total resource) is available with no cost increase, 3.3% (387 GW) is available with a 10% cost increase, 2% (240 GW) is available with a 25% cost increase, and more than 90% of windy land is available with a 50% or 100% cost increase.

Other

- Because of downwind turbulence and other aerodynamic effects, the model assumes an average spacing between turbine rows of 5 rotor diameters and a lateral spacing between

turbines of 10 rotor diameters. This spacing requirement determines the amount of power that wind resources can generate (about 6.5 MW per square kilometer of windy land), which the EMM factors into requests for generating capacity.
- We assume a three-year construction lead time for start of construction to project completion for onshore wind and four years for offshore wind.
- Existing capacity and planned capacity additions are based on our survey data from Form EIA-860, *Annual Electric Generator Report,* and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The model includes planned capacity additions under construction or with an expected completion date before the end of 2024, according to respondents' planned completion dates.

Offshore wind

The RFM represents offshore wind resources as a separate technology from onshore wind resources, although they are modeled with a similar model structure as onshore wind. Because of the unique challenges of offshore construction and the somewhat different resource quality, the assumptions for capital cost, learning-by-doing cost reductions, and the resource access cost differ significantly from onshore wind.

Technology

- Because of the maintenance challenges in the offshore environment, we assume that performance for a given annual average wind power density is somewhat decreased by reduced turbine availability. Offsetting this challenge, however, are resource areas with higher overall power density than what we assume is available onshore. Capacity factors for offshore start at 50% and are limited to 58% for a Class 7 site.

Cost

- Cost reductions in offshore technology result, in part, from learning reductions in onshore wind technology as well as from cost reductions unique to offshore installations, such as foundation design and construction techniques. Because offshore technology is significantly less mature than onshore wind technology, offshore-specific technology learning occurs at a somewhat faster rate than for onshore technology. A technological optimism factor is included for offshore wind to account for the substantial cost of establishing the unique construction infrastructure required for this technology, as indicated in *The Electricity Market Module of the National Energy Modeling System: Model Documentation 2022*.

Resources

- As with onshore wind resources, we assume offshore wind resources have an upward-sloping cost supply curve, which is affected primarily by water depth. Offshore supply costs are also affected by the same factors, in part, that determine the onshore supply curve (such as distance to load centers, environmental or aesthetic concerns, and variation in terrain [in this case, seabed]).

Geothermal Electricity Submodule

Background

We base the geothermal supply curve data on NREL's updated U.S. geothermal supply curve assessment. The U.S. Geologic Service (USGS) uses the Geothermal Electricity Technology Evaluation Model (GETEM) (a techno-economic systems analysis tool) to estimate the costs for resources identified in its 2008 geothermal resource assessment.[8, 9] We only consider resources with temperatures higher than 110°C. We use 125 of these known hydrothermal resources in the geothermal supply curve. NREL classifies each of these sites as *near-field enhanced geothermal energy system potential*, which are areas around the identified site that lack the permeability of fluids that are present in the hydrothermal potential. We assume, therefore, that the supply curve has 250 total points because each of the 125 hydrothermal sites has corresponding enhanced geothermal system (EGS) potential.

Some data from the 2006 report, *The Future of Geothermal Energy* (prepared for Idaho National Laboratory by the Massachusetts Institute of Technology)[10] are also incorporated into the NREL report; however, the data apply more to deep, dry, and unknown geothermal resources, which we did not include in the geothermal supply curve.

In the past, our cost estimates were broken down into cost-specific components. This level of detail is not available in the NREL data. NREL provides a site-specific capital cost and a fixed operations and maintenance cost. NREL data also include two types of technology—flash and binary cycle–and their capacity factors range from 90% to 95%. We modeled only binary cycle as our geothermal capacity technology.

Assumptions

- We assume a four-year construction lead time for start of construction to projected completion for a geothermal facility.
- We base existing capacity and planned capacity additions on our survey data from Form EIA-860, *Annual Electric Generator Report,* and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The model includes planned capacity additions under construction or that we expect to be completed before the end of 2024, according to respondents' planned completion dates.

Biomass Submodule

Background

NEMS models biomass consumed for electricity generation in two parts. The IDM includes capacity in the wood products and paper industries (also known as captive capacity) as cogeneration. We represent generation in the electric power sector in the EMM. The RFM calculates the fuel costs and passes them to the EMM, and we assume capital and operating costs and performance characteristics, as shown in Table 2 of the EMM assumptions document. The EMM provides fuel costs in sets of regional supply schedules. The LFMM projects ethanol production and gradually decreases the quantities and prices of biomass consumed for ethanol from the EMM regional supply schedules.

Assumptions

Technology

- The conversion technology represents a 50-MW dedicated combustion plant. We base the cost estimates for this technology on the Sargent & Lundy report, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, published in 2020.

Resources

- Fuel supply schedules consist of four fuel sources: forestry materials from federal forests, forestry materials from non-federal forests, wood residues, and agricultural residues and energy crops. We calculate feedstock potential from agricultural residues and dedicated energy crops from a version of the Policy Analysis Systems Model (POLYSYS) that uses the same oil price information as the rest of NEMS.
- We calculate forestry residues from inventories conducted by the U.S. Forest Service and Oak Ridge National Laboratory (ORNL). The forestry materials component is made up of logging residues, rough rotten salvageable dead wood, and excess small pole trees.[11] The maximum resources from forestry is fixed, based on *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*, prepared by ORNL.[12]
- The wood residue component consists of primary mill residues; silvicultural trimmings; and urban wood, such as pallets, construction waste, and demolition debris that are not otherwise used.[13] Urban wood waste is determined dynamically based on activity in the industry sectors that produces usable biomass feedstocks, passed to the RFM from the IDM.
- Agricultural residues are wheat straw, corn stover, and a number of other major agricultural crops.[14] Energy crop data are for hybrid poplar, willow, and switchgrass grown on existing cropland. Agricultural resource supply (agricultural residues and energy crops) is determined dynamically, and supplies available within the model at any point may not reflect the maximum potential for that region. POLYSYS assumes that the additional cropland needed for energy crops will displace existing pasturelands.

Other

- Biomass cofiring can account for up to 15% of fuel used in coal-fired generating plants.
- We assume a four-year construction lead time for start of construction to project completion for biomass facilities.
- We base existing capacity and planned capacity additions on our survey data from Form EIA-860, *Annual Electric Generator Report,* and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The model includes planned capacity additions under construction or that we expect to be completed before the end of 2024, according to respondents' planned completion dates.

Landfill Gas (LFG) Submodule

Background

LFG-to-electricity capacity competes with other technologies using supply curves that are based on the amount of high, low, and very low methane-producing landfills in each EMM region. Starting with AEO2021, we model LFG generation facilities as primarily built to serve municipal waste disposal markets with electric power generation as a secondary product (rather than as a capacity expansion option to the electric power sector). Based on the historical ratio between generation and municipal waste landfill capacity, the LFG Submodule produces year-specific streams of national landfill capacity for LFG development from both new landfills and landfills with existing LFG projects. The national LFG generation estimates are proportioned to EMM regions.

Assumptions

Resources

- GDP and population are the drivers in the econometric equation that establishes the LFG supply.
- We use EPA's Landfill Methane Outreach Program (LMOP) landfill database[15] to determine available methane resources (in tonnage and five-year increments) and project-development timelines. We use LMOP's *Candidate* landfills for new landfills and use *Probable* landfills only if the module has exhausted the potential from *Candidate* landfills.

Other

- We base existing capacity and planned capacity additions on our survey data from Form EIA-860, *Annual Electric Generator Report,* and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The model includes planned capacity additions under construction or that we expect to be completed before the end of 2024, according to respondents' planned completion dates.

Conventional Hydroelectricity Submodule

Background

The Conventional Hydroelectricity Submodule represents potential for new U.S. conventional hydroelectric capacity of 1 MW or greater from new dams, from existing dams without hydroelectricity, and from additional capacity at existing hydroelectric dams.

Assumptions

Technology

- The supply curve of potential new hydroelectric capacity includes both seasonal storage and run-of-river applications. It also includes both undeveloped sites and sites with existing dam, diversion, or generating facilities.
- The supply excludes pumped-storage hydroelectric capacity, but we model the operation of existing pumped hydro facilities.

- The supply neither considers offshore or in-stream hydroelectric efficiency or operational improvements without capital additions, nor does it consider additional potential from refurbishing existing hydroelectric capacity.

Cost

- We estimate costs for each site in the resource database, as indicated in the Resources section.

Resources

- We derive the summary hydroelectric potential from reported lists of potential new sites assembled from Federal Energy Regulatory Commission (FERC) license applications and other survey information and from estimates of capital and other costs prepared by the Idaho National Engineering and Environmental Laboratory (INEEL).[16]
- For AEO2018, we updated resource characteristics for existing non-powered dams based on ORNL's An Assessment of Energy Potential at Non-Powered Dams in the United States.

Other

- For annual performance estimates (capacity factors), we use the generally lower, but site-specific, FERC estimates rather than the general estimates prepared by INEEL, and the supply includes only sites with estimated costs of 10 cents per kilowatthour (kWh) or lower.
- We base existing capacity and planned capacity additions on our survey data from Form EIA-860, *Annual Electric Generator Report,* and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The model includes planned capacity additions under construction or that we expect to be completed before the end of 2024, according to respondents' planned completion dates.

Legislation and regulations

Renewable electricity tax credits

The federal tax credits available to certain renewable electric-generating technologies initiated in the Energy Policy Act of 1992 (EPACT1992) and amended in the Energy Policy Act of 2005 (EPACT2005) have been further amended through a series of acts that we have implemented in NEMS over time. AEO2023 reflects the most recent changes implemented through the Inflation Reduction Act of 2022 (IRA).

The production tax credit (PTC) is a per-kilowatthour tax credit on electricity sold for a specific number of years after the facility has been placed in service. The investment tax credit (ITC) is a tax credit applied, on a percentage basis, to the cost of building certain electric-generating assets. The IRA modifies and extends the tax credits that were previously scheduled to reduce or expire for certain technologies. Furthermore, the IRA creates technology-neutral tax credits for facilities with zero emissions placed in service starting in 2025. The clean energy ITC has a base value of 6%, and the clean energy PTC has a base value of 0.3 cents/kWh and is adjusted for inflation each year. The ITC and PTC are exclusive of one another, and the same facility cannot claim both. For AEO2023, the tax credit extensions and modified tax credit values. In addition, we assume all renewable technologies meet the prevailing wage and apprenticeship requirements for a bonus credit, increasing the base tax credits by five times. Onshore and offshore wind technologies also meet the domestic content requirements for a 10% additional tax credit. We don't have enough information at this time on potential implementation of bonus credits for the energy communities and assume it will not be widely applied. We will specifically implement the tax credits for renewable generation sources as follows:

- Solar generators can choose between claiming the PTC or the ITC; only the ITC was available previously. Along with the guidance on the beginning-of-construction requirement and the Continuity Safe Harbor provided in Internal Revenue Service (IRS) Notice 2021-41, we assume standalone solar PV facilities will claim the PTC for the first 10 years of operation. Without further guidance on tax credit for PV-battery, hybrid facility, we assume for AEO2023 that PV-battery, hybrid facilities will be eligible for and will claim the PTC. CSP projects will continue to claim the ITC because of the much higher capital cost of CSP projects.
- The IRA eliminates the previous phaseout schedule of available tax credits for onshore wind facilities. We assume that onshore wind projects will claim the PTC during the plant's first 10 years of service, based on a four-year lag between start of construction and project completion, consistent with current IRS guidance. In addition, we assume onshore wind projects meet the domestic content requirements for additional tax credits.
- Along with the guidance on the beginning of construction requirement and the Continuity Safe Harbor provided in IRS Notice 2021-05, we assume offshore wind projects will claim the ITC because of the high capital costs for those projects. In addition, we assume offshore wind projects will satisfy the domestic content requirements by 2032 and after for additional tax credits.
- Starting in the 2025 online year, we assume:
- Geothermal projects will claim the ITC.
- Biomass projects will claim the PTC for the first 10 years of operation.
- Hydroelectric projects will claim the ITC instead of the PTC as previously allowed.

The tax credits are available to all eligible technologies until 2032, after which they are phased out if an emissions reduction threshold is met. As of finalization of AEO2023, additional guidance on emission accounting rules that will be used to evaluate the emissions reduction threshold has not been finalized. Based on our understanding of which emissions may be counted toward the emissions reduction without additional guidance, we assume no phaseout of the tax credits in AEO2023 Reference case.

State-level requirements for offshore wind

AEO2023 includes installed capacity targets for offshore wind for states with specified requirements. A more detailed list of state requirements for offshore wind is included in the *Summary of Legislation and Regulations Included in the Annual Energy Outlook 2023* report.

State clean energy standard programs

To the extent possible, AEO2023 reflects state laws and regulations enacted as of November 2022, which establish minimum requirements for renewable generation or capacity for load-serving entities operating in the state. These requirements represent clean energy standards (CES). AEO2023 projections do not include voluntary goals but do include clean energy targets set forth by state-level executive branch entities.

We estimate zero-emission generation targets by using the zero-emission generation targets in each state within the NEMS region. In many cases where regional boundaries intersect state boundaries, state requirements are divided among relevant regions based on sales. Required generation in each state is then summed to the regional level for each year to determine a regional compliant generation share of total sales.

We model any non-discretionary limitations on meeting the generation or capacity target to the extent possible. However, because of the complexity of the various requirements, the regional target aggregation, and the nature of some of the limitations, we estimate compliance.

Compliance enforcement provisions vary significantly across states, and most states have procedures for waiving compliance, such as alternative compliance payments, penalty payments, discretionary regulatory waivers, or retail price impact limits. Because of the variety of mechanisms, even within a given electricity market region, we do not model these limits.

Most states already meet or exceed their required renewable generation mix, based on qualified generation or purchases of renewable energy credits (RECs).[17] A number of factors helped make CES compliance attainable for generators, including:

- New CES-qualified generation capacity timed to take advantage of federal incentives
- Lower cost of wind, solar, and other renewable technologies
- State and local policies that either reduce costs (for example, equipment rebates) or increase revenue streams (for example, net metering) associated with CES-eligible technologies
- Credit trading among compliant entities within a state and across state boundaries

Notes and sources

[1] For a comprehensive description of each submodule, see U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, *Renewable Fuels Module of the National Energy Modeling System: Model Documentation 2020*, DOE/EIA-M069(2020) (Washington, DC, June 2020), https://www.eia.gov/outlooks/aeo/nems/documentation/renewable/pdf/m069(2020).pdf.
[2] U.S. Energy Information Administration*, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies* (Washington, DC, February 2020), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.
[3] Sengupta, M., Y. Xie, A. Lopez, A. Habte, G. Maclaurin, and J. Shelby, "The National Solar Radiation Data Base (NSRDB)." *Renewable and Sustainable Energy Reviews* 89 (June 2018), pp. 51–60.
[4] National Renewable Energy Laboratory System Advisor Model, https://sam.nrel.gov/.
[5] The inverter loading ratio (ILR) is the ratio between the rated capacity of the DC (direct current) solar array and the AC (alternating current) power rating of the inverter.
[6] For details on inverter loading ratio assumptions, see U.S. Energy Information Administration*, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies* (Washington, DC, February 2020), http://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.
[7] *Revising the Long Term Multipliers in NEMS: Quantifying the Incremental Transmission Costs Due to Wind Power*, report to EIA from Princeton Energy Resources International, LLC, May 2007.
[8] Augustine, C., *Updated U.S. Geothermal Supply Characterization and Representation for Market Penetration Model Input*, NREL/TP-6A20-47459 (Golden, CO, October 2011), https://www.nrel.gov/docs/fy12osti/47459.pdf .
[9] The one exception applies to the Salton Sea resource area, for which we used cost estimates provided in a 2010 report on electric power sector capital costs rather than NREL.
[10] Idaho National Laboratory, *The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems on the United States in the 21st Century*. INL/EXT-06-11746 (Idaho Falls, ID 2006), https://inldigitallibrary.inl.gov/sites/sti/sti/3589644.pdf.
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