Renewable Fuels Module

The U.S. Energy Information Administration's (EIA) National Energy Modeling System (NEMS) Renewable Fuels Module (RFM) provides supply and technology input information for natural resources for projections of new utility scale U.S. electricity 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), and wind (offshore and onshore) [1].

The submodules of the RFM interact primarily with the Electricity Market Module (EMM) within NEMS. The EMM represents the capacity planning, dispatching, and pricing of electricity. Because of the high level of integration with the EMM, the final outputs (levels of consumption and market penetration over time) for renewable energy technologies are largely dependent on the EMM.

Some types of biomass fuel can be used for either electricity generation or for liquid fuels production, such as ethanol. As a result, the RFM also interacts with the Liquid Fuels Market Module (LFMM), which contains additional representation of some biomass feedstocks that are used primarily for liquid fuels production.

Projections for residential and commercial grid-connected photovoltaic systems are developed in the end-use demand modules and are not included in the RFM; see the Commercial Demand Module (CDM) and Residential Demand Module (RDM) sections of this Assumptions report. Descriptions for 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 electricity generation systems using biomass, geothermal, conventional hydroelectricity, LFG, solar (thermal and photovoltaic), and wind (offshore and onshore) as energy sources. Each submodule provides specific data or estimates that characterize the respective resources. The EMM includes the evaluation of the technologies, including the build and dispatch decisions. Table 2 in the EMM Assumptions 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* 2020 (AEO2020) contains projections of nonelectric renewable energy consumption for industrial and residential wood heating, solar residential and commercial hot water heating, biofuels blending in transportation fuels, and residential and commercial geothermal (ground-source) heat pumps. Assumptions for these projections are in the RDM, CDM, IDM, and LFMM sections of this report. Additional minor renewable energy applications that occur outside of energy markets, such as direct solar thermal industrial applications, direct lighting, off-grid electricity generation, and heat from geothermal resources used directly (for example, district heating and greenhouses) are not included in the projections.

Capital costs

The EMM Assumptions document describes the methodology used to determine initial capital costs and cost-learning assumptions. For AEO2020, EIA hired a consultant to update current cost estimates for most utility-scale electric generating plants [2]. This report used a consistent estimation methodology across all technologies to develop cost and performance characteristics for technologies specified by EIA for consideration in the EMM. EIA did not use costs developed for geothermal and hydroelectric plants where previously developed site-specific costs continue to be used. Costs for distributed generation plants in the power sector were also not updated for this report, and input assumptions remain as in previous AEOs. Inputs for all other technologies listed in Table 2 were updated for AEO2020.

Except as noted below, the overnight costs shown in Table 2 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 broken out as in previous AEOs, the base overnight costs include project contingency to account 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. A cost-adjustment factor, based on the producer price index for metals and metal products, allows 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, capital costs to develop the resources are assumed to be dependent on the quality, accessibility, or other site-specific factors in the areas with exploitable 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 U.S. buildup in a single year, short-term cost adjustment factors are used to increase technology capital costs, reflecting limitations on the infrastructure (for example, limits on manufacturing, resource assessment, and construction expertise). These factors, which are applied to all new electric generation 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 2018* report.

Costs associated with construction commodities such as bulk metals and concrete are also assumed to 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 Module of NEMS. Independent of the other two factors, capital costs for all electric generation technologies, including renewable technologies, are assumed to decline as a function 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 the EIA publication, *Renewable Fuels Module of the National Energy Modeling System: Model Documentation 2018*, DOE/EIA-M069 (2018) Washington, DC, 2018.

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).

Available solar capacity and its associated capacity factors are passed from the solar submodule in RFM to the EMM for capacity planning and dispatch decisions. These characteristics form the basis on which the EMM decides how much power generation capacity is available from solar energy.

Assumptions

Technology

- Only grid-connected utility-scale generation is included in the RFM. Projections for end-use solar PV generation are included in the CDM and RDM.
- 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 array of flat-plate PV modules with a latitudinal-based angle fixed-tilt axis. Solar PV is assumed to be available in all EMM regions.

Cost

- Cost data for the single-axis tracking PV system used in NEMS are based on a report by Sargent & Lundy, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies,* published in 2020.
- Regional cost adjustments reflect location-based cost adjustments in each EMM region for PV technology as provided by Sargent & Lundy.

- The cost estimates for CSP are based on the Sargent & Lundy report, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, published in 2020.

Resources

- Available solar resources are reduced by excluding all lands not suited for solar installations, such as reservation of land for non-intrusive uses (national parks, wildlife refuges, etc.) and 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, between 1.2 and 1.3) [4][5]. Increased ILRs introduce excessive solar clipping, where solar generation is lost by exceeding the inverter's rated output power. Since AEO2017, we have been estimating solar PV capacity factors with an ILR of 1.25 by using the NREL's System Advisor Model (SAM) to develop a more accurate time-of-day and seasonal output profile.
- In the regions where CSP technology is not modeled, the level of direct, normal insolation (the type required for that technology) is assumed to be insufficient to make that technology commercially viable through the projection period.

Other

- NEMS represents the investment tax credit (ITC) that is available for solar electric power generators. The ITC provides a credit to federal income tax liability as a percentage of the initial investment cost for a qualified renewable generating facility. In June 2018, the IRS issued Notice 2018-59 to provide guidance for the beginning of the qualified construction period for solar plants. EIA assumes the following:
  - 30% tax credit for projects starting construction before January 1, 2020, and entering service before January 1, 2024
  - 26% tax credit for projects starting construction in 2020 and entering service before January 1, 2024
  - 22% tax credit for projects starting construction in 2021 and entering service before January 1, 2024
  - 10% tax credit for projects beginning construction after 2021
- For utility-scale solar PV projects, EIA assumes a two-year construction lead time between start of construction and project completion.
- Existing capacity and planned capacity additions are based on EIA survey data from the Form EIA-860, *Annual Electric Generator Report,* and the Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The model includs planned capacity additions under construction or with an expected completion date before the end of 2019, according to respondents' planned completion dates.

Wind energy power submodule

Background

The wind submodule represents both offshore and onshore wind resources at a hub height of 80 meters and by categorizing annual average wind speeds based on a classification system originally from 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 [6]. 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 economically available wind capacity and its associated capacity factors are passed from the wind submodule in RFM to the EMM for capacity planning and dispatch decisions. These characteristics form the basis from which the EMM decides how much power generation capacity is available from wind energy.

Assumptions

Technology

- Only grid-connected utility-scale wind generation is included in the RFM. Projections for distributed wind generation are included in the CDM and RDM.
- Capacity factors for each wind class are calculated as a function of overall wind market growth. EIA implements an algorithm that increases the capacity factor within a wind class as more units enter service (learning). The capacity factors for each wind class are assumed to start at 48% and are limited to 55% for a Class 6 site. However, despite increasing performance of the technology, as better wind resources are depleted, the modeled capacity factors for new builds may decline within a given region, corresponding with the use of less desirable sites.

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, and other market variables.
- As with all technologies, wind technology capital costs decline with increasing market builds (learning). Because wind resources are limited within any given 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
    - Increasing costs of upgrading existing local and network distribution and transmission lines to accommodate growing quantities of remote wind power
    - Market conditions, such as the increasing costs of alternative land uses, including aesthetic or environmental reasons.

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

Resources

- Available wind resources are reduced by excluding all windy lands not suited for wind turbines because of
  - Excessive terrain slope (greater than 20%)
  - Reservation for non-intrusive uses (such as national parks, wildlife refuges, etc.)
  - 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)
- Half of the wind resources located on military reservations, U.S. Forest Service land, state forested land, and all non-ridge-crest forest areas are excluded from the available resource base to account for the uncertainty about siting projects at such locations. Appendix 3-E of *Renewable Fuels Module of the National Energy Modeling System: Model Documentation* details these assumptions.
- 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% 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 can be generated from wind resources (about 6.5 MW per square kilometer of windy land) and is factored into requests for generating capacity by the EMM.
- As a result of the Consolidated Appropriations Act of 2016, passed in December 2015, and the assumption of a three-year construction lead time, AEO2020 allows wind plants under construction by the end of 2016 to claim the full 2.4 cents per kilowatthour (2019 cent/kWh) federal production tax credit (PTC) through the end of 2020. The PTC declines for wind projects under construction after December 31, 2016, as follows
  - 80% of the current PTC value (1.9 cents/kWh) for projects that begin construction in 2017 and enter service before 2022
  - 60% of the current PTC value (1.4 cents/kWh) for projects that begin construction in 2018 and enter service before 2023
  - 40% of the current PTC value (0.9 cents/kWh) for projects that begin construction in 2019 and enter service before 2024

    - PTC is not available for those projects that begin construction after December 31, 2019
- As noted above, EIA assumes that wind projects are eligible for 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.

Offshore wind

Offshore wind resources are represented 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 resource access cost differ significantly from onshore wind.

Technology

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

Cost

- Cost reductions in the 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 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 EMM documentation.

Resources

- Like onshore resources, offshore resources are assumed to have an upward-sloping cost supply curve, influenced explicitly by water depth but also in part by the same factors that determine the onshore supply curve (such as distance to load centers, environmental or aesthetic concerns, and variable terrain/seabed).

Other

- Both onshore and offshore wind projects are eligible to claim the ITC in place of the PTC. Although EIA assumes that onshore wind projects would choose the PTC, EIA assumes offshore wind projects will claim the ITC because of the high capital costs for those projects.

The ITC claimed by offshore wind projects is subject to the same phasedown schedule as the PTC:

- 30% tax credit for projects starting construction before January 1, 2020, and entering service before January 1, 2024
- 26% tax credit for projects starting construction in 2020 and entering service before January 1, 2024
- 22% tax credit for projects starting construction in 2021 and entering service before January 1, 2024
- 10% tax credit for projects beginning construction after 2021

Geothermal Electricity Submodule

Background

Geothermal supply curve data are based on NREL's updated U.S. geothermal supply curve assessment, which used the Geothermal Electricity Technology Evaluation Model (GETEM), a techno-economic systems analysis tool, to estimate the costs for resources identified in the U.S. Geological Survey's (USGS) 2008 geothermal resource assessment [7,8]. Only resources with temperatures higher than 110 degrees Celsius were considered. EIA uses about 125 of these known hydrothermal resources in the geothermal supply curve. Each of these sites is classified by NREL as *near-field enhanced geothermal energy system potential*, which are in areas around the identified site that lack the permeability of fluids that are present in the hydrothermal potential. EIA assumes, 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 [9], are also incorporated into the NREL report; however, the data apply more to deep, dry, and unknown geothermal resources, which EIA did not include in its supply curve.

In the past, EIA cost estimates were broken down into cost-specific components. This level of detail is not available in the NREL data, however. A site-specific capital cost and fixed operations and maintenance cost are provided. Two types of technology—flash and binary cycle—are also included, and their capacity factors range from 90% to 95%.

Assumptions

- Existing and identified planned capacity data are obtained directly by the EMM from Form EIA-860 and Form EIA-860M.
- The permanent ITC of 10%, available in all projection years, based on the Energy Policy Act of 1992 (EPACT92), applies to all geothermal capital costs.

Biomass Submodule

Background

Biomass consumed for electricity generation is modeled in two parts in NEMS. Capacity in the wood products and paper industries (the so-called captive capacity) is included in the IDM as cogeneration. Generation in the electricity sector is represented in the EMM. Fuel costs are calculated in RFM and passed to EMM, and capital and operating costs and performance characteristics are assumed as shown in Table 2 of the EMM Assumptions document. Fuel costs are provided in sets of regional supply schedules. Projections for ethanol production are produced by the LFMM, and the quantities and prices of biomass consumed for ethanol are gradually decreased from the EMM regional supply schedules.

Assumptions

Technology

- Existing and planned capacity data are obtained from Form EIA-860 and Form EIA-860M.
- The conversion technology represented is a 50 MW dedicated combustion plant. The cost estimates for this technology are based on the Sargent & Lundy report, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, published in 2020.

Other

- Biomass cofiring can occur up to a maximum of 15% of fuel used in coal-fired generating plants.
- 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. Feedstock potential from agricultural residues and dedicated energy crops are calculated from a version of the Policy Analysis (POLYSYS) agricultural model that uses the same oil price information as the rest of NEMS.
- Forestry residues are calculated 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 [10]. The maximum amount of resources from forestry is fixed based on *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry* prepared by ORNL [11].
- 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 [12]. Urban wood waste is determined dynamically based on activity in the industry sectors that produce 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 [13]. Energy crop data are for hybrid poplar, willow, and switchgrass grown on existing cropland. Agricultural resource (agricultural residues and energy crops) supply 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.

In 2040, the estimated supplies of the feedstock categories include agricultural residues and energy crops, estimated at 4,830 trillion British thermal unit (Btu); wood residues, estimated at 922 trillion Btu; and forestry materials (from public and private lands), estimated at 1,915 trillion Btu. In 2050, the estimated supplies of the feedstock categories include agricultural residues and energy crops, estimated at 5,759 trillion British thermal unit (Btu); wood residues, estimated at 921 trillion Btu; and forestry materials (from public and private lands), estimated at 1,915 trillion Btu. For 2040, supplies of 290 trillion Btu from all sectors could be available given prevailing demand in the AEO2020 Reference case. For 2050, supplies of 358 trillion Btu from all sectors could be available given prevailing demand in AEO2018.

Landfill gas (LFG) submodule

Background

Landfill gas-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 located in each EMM region. An average cost of electricity for each type of landfill is calculated using a gas collection system and electricity generator costs and characteristics developed by the U.S. Environmental Protection Agency's (EPA) Energy Project Landfill Gas Utilization Software (E-PLUS) [14].

Assumptions

Technology

- The ratio of high, low, and very low methane production sites to total methane production is calculated from data obtained for the 156 operating landfills included in the Governmental Advisory Associates Inc., METH2000 database [15].

Cost

- Cost of electricity for each site was calculated by assuming each site to be a 100-acre by 50-foot-deep landfill and applying methane emission factors for high, low, and very low methane-emitting wastes.

Resources

- Gross domestic product (GDP) and population are the drivers in an econometric equation that establishes the supply of landfill gas.
- The waste stream is characterized into three categories: readily, moderately, and slowly decomposable material.

Other

- Recycling is assumed to account for 50% of the waste stream in 2010 (consistent with EPA's recycling goals).
- Emission parameters are the same as those used in calculating historical methane emissions in EIA's *Emissions of Greenhouse Gases in the United States 2003* [16].

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 adding capacity at existing hydroelectric dams.

Assumptions

Technology

- The supply curve of potential new hydroelectric capacity includes both seasonal storage and run-of-river applications and both undeveloped sites and sites with existing dam, diversion, or generating facilities.
- Pumped storage hydroelectric is not included in the supply, although operation of existing pumped hydro facilities is modeled.
- The supply does not consider offshore or in-stream hydroelectric efficiency or operational improvements without capital additions, nor does it consider additional potential from refurbishing existing hydroelectric capacity.

Cost

- Costs are estimated for each site in the resource database, as indicated in the Resources section below.

Resources

- Summary hydroelectric potential is derived 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) [17].
- For AEO2018, EIA updated resource characteristics for existing non-powered dams based on the ORNL report, *An Assessment of Energy Potential at Non-Powered Dams in the United States*.

Other

- Annual performance estimates (capacity factors) are taken from the generally lower but site-specific FERC estimates rather than the general estimates prepared by INEEL, and only sites with estimated costs of 10 cents/kWh or lower are included in the supply.
- The RFM incorporates the extended PTC expiration date for incremental hydroelectric generation as enacted by the 2016 Consolidated Appropriations Act. Qualifying facilities receive the PTC if they were built within the timeframe specified by the law and its various extensions. These facilities can claim the tax credit on generation sold during their first 10 years of operation.

ReStore submodule (intermittent/storage modeling)

For AEO2019, a new submodule within the EMM was introduced to provide the additional details we needed to represent renewable availability at a greater level of detail beyond the nine time slices previous used and discussed in detail in the *Assumptions to the Annual Energy Outlook 2019: Electricity Market Module*. We also needed a new submodule to adequately model the value of the four-hour battery storage technology, which can balance renewable generation in periods of high intermittent output but low demand. The ReStore submodule solves a set of linear programming subproblems within the EMM to provide the capacity planning and dispatch models information regarding the value of battery storage and the level of variable renewable energy curtailments. The subproblems solve a set of 576 representative hours for the year, based on the average 24-hour weekday and weekend demand pattern for each month of the year. Results are aggregated back to the nine time slices for the EMM. The ReStore submodule incorporates improved representation of hydro-electric dispatch, determines wind and solar generation and any required curtailments, and determines the optimal use of any battery storage capacity. The submodule determines the annual load-shifting arbitrage value of one or more increments of an energy storage technology, provides information regarding renewable generation curtailments, and provides information regarding the dispatch of existing hydroelectric, solar, and wind capacity to inform the ECP and EFD load slice dispatch. Because it includes hourly level dispatch, it represents the costs or constraints to ramping conventional technologies up and down to respond to fluctuations in intermittent generation. It also provides the planning model information on the value of storage to determine future builds.

The ReStore submodule dispatches existing generation capacity to meet hourly load in each region at a minimum cost. This process includes the dispatch of conventional generating technologies as well as wind, solar, hydroelectric, and storage technologies subject to their fuel and variable O&M costs. Although the EMM regions are assumed to be separate problems in this approach, all of the regional subproblems are combined into a single linear program to be solved simultaneously.

Legislation and regulations

Renewable electricity tax credits

The RFM includes the investment and energy production tax credits codified in EPACT92 as amended.

The ITC provides a credit to federal income tax liability as a percentage of initial investment cost for a qualified renewable generating facility. In June 2018, the IRS issued Notice 2018-59, for beginning of construction guidance for the ITC. EIA assumes all solar projects starting construction before January 1, 2020, have four years to bring the power plant online (before January 1, 2024) to receive the full 30% ITC. Solar projects include both utility-scale solar plants—those with a capacity rating of 1 megawatt (MW) or greater—and small-scale systems—those with a capacity rating of less than 1 MW. Projects starting construction in 2020 have three years to enter service and receive a 26% ITC, and those with a 2021 construction start year have two years to enter service to claim a 22% ITC. All commercial and utility-scale plants with a construction start date on or after January 1, 2022, or those placed in service after December 31, 2023, receive a 10% ITC. The 30% residential tax credit for ground-source heat pumps, solar PV, solar thermal water heaters, and small wind turbines applies to installations through 2021 only, and then it is eliminated in subsequent years. This change is reflected in the CDM and RDM.

The PTC is a per-kWh tax credit available for qualified wind, geothermal, closed-loop and open-loop biomass, landfill gas, municipal solid waste, hydroelectric, and marine and hydrokinetic facilities. The value of the credit, originally 1.5 cents/kWh in 1993, is adjusted for inflation annually and is available for 10 years after the facility is placed in service. For AEO2020, wind resources receive a tax credit of 2.4 cents/kWh; all other renewable resources receive a 1.2 cent/kWh tax credit (that is, one-half the value of the credit for other resources). EIA assumes that biomass facilities obtaining the PTC will use open-loop fuels [18] because closed-loop fuels are assumed to be unavailable or too expensive for widespread use during the period the tax credit is available. The PTC has been recently extended by the Consolidated Appropriations Act of 2016 passed in December 2015 for wind projects through 2016. The PTC is scheduled to phase down in value for wind projects as follows

- 80% of the current PTC if it begins construction in 2017 and is operating before 2022
- 60% of the current PTC if it begins construction in 2018 and is operating before 2023
- 40% of the current PTC if it begins construction in 2019 and is operating before 2024

Both onshore and offshore wind projects are eligible to claim the ITC in place of the PTC. Although onshore wind projects are expected to choose the PTC, EIA assumes offshore wind projects will claim the ITC because of the high capital costs for those projects. The ITC claimed by offshore wind projects is subjected to the same phasedown schedule as the PTC.

The ITC and PTC are exclusive of one another and therefore may not each be claimed for the same facility.

Further details on the PTC and ITC modeling assumptions can be found in the technology-specific sections of this document. A history of these tax credits is described in AEO2016 Legislation and Regulations LR3—*Impact of a Renewable Energy Tax Credit* extension and phaseout [19].

State-level mandates for offshore wind and battery storage

In AEO2020, states that have specified installed capacity requirements for offshore wind and diurnal battery storage are included. A more detailed list of state requirements for offshore wind and diurnal battery storage is included in the AEO2020 Legislation and Regulations document, published in 2020.

State renewable portfolio standards programs

EIA represents various state-level policies that require the addition of renewable generation to meet a specified share of state-wide generation, generally referred to as renewable portfolio standards (RPS)—Table 1. These policies vary significantly among states. AEO2020 includes technology-specific carve-outs, which require a certain percentage of generation to come from a specified technology. These carve-outs are in addition to any technology restrictions put in place by the respective RPS legislations. Any non-discretionary limitations on meeting the generation or capacity target are modeled 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, the compliance rate is an estimate.

Regional renewable generation targets are estimated using the renewable generation targets in each state within the NEMS region. In many cases where regional boundaries intersect state boundaries, state requirements were divided among relevant regions based on sales. Required generation in each state was then summed to the regional level for each year, and a regional renewable generation share of total sales was determined.

Only targets with established enforcement provisions or established state funding mechanisms are included in the calculation; non-enforceable goals are not included. Compliance enforcement provisions vary significantly across states, and most states have established procedures for waiving compliance through the use of 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, these limits are not modeled.

Table 1. Aggregate state renewable portfolio standards requirements

(billion kilowatthours, millions of renewable energy credits)

State	2020	2030	2040	2050
Arizona	4.4	7.3	8.2	9.4
California	83.0	154.3	239.6	311.1
Colorado	10.0	11.2	12.5	14.3
Connecticut	6.9	12.5	13.2	14.4
Delaware	1.9	2.4	2.5	2.7
District of Columbia	2.9	9.7	11.8	12.8
Illinois	14.1	23.6	25.0	26.9
Iowa	0.3	0.3	0.3	0.3
Maine	3.0	9.0	10.7	13.0
Maryland	17.7	31.6	33.5	36.4
Massachusetts	9.7	19.5	26.3	34.7
Michigan	12.4	16.0	16.9	18.2
Minnesota	16.9	20.1	21.4	23.1
Missouri	5.2	8.4	9.0	9.7
Montana	1.1	1.2	1.3	1.4
Nevada	5.7	11.5	24.1	52.4
New Hampshire	2.2	2.7	2.9	3.1
New Jersey	18.3	42.2	44.0	47.7
New Mexico	4.2	11.6	20.7	29.4
New York	22.3	80.6	120.8	129.8
North Carolina	13.2	17.1	18.7	20.8
Ohio	7.2	12.0	12.7	13.7
Oregon	6.5	11.2	14.5	16.3
Pennsylvania	21.7	26.1	27.7	30.0
Rhode Island	1.1	2.3	3.0	3.3
Texas	18.2	18.4	18.5	18.7
Vermont	3.2	3.9	4.4	4.7
Washington	11.0	21.5	43.6	92.2
Wisconsin	6.7	7.2	7.6	8.2

Source: Various state laws and regulations as implemented in AEO2020. AEO2020 only considered policies signed into law as of September 30, 2019; state policies signed into law after that date are not included for this AEO. For a more complete overview of specific state targets, along with links to current controlling policies and regulatory actions, see the Database of State Incentives for Renewable Energy.

Notes and sources

[1] For a comprehensive description of each submodule, see U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, *Model Documentation, Renewable Fuels Module of the National Energy Modeling System*, DOE/EIA-M069(2018) (Washington, DC, December 2018), https://www.eia.gov/outlooks/aeo/nems/documentation/renewable/pdf/m069(2018).pdf.

[2] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, Sargent & Lundy, December 2019.

[3] National Renewable Energy Laboratory Geospatial Data Science, *Solar Data, Lower 48 and Hawaii GHI 10-km Resolution 1998–2009*, https://www.nrel.gov/gis/data-solar.html.

[4] 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.

[5] For details on inverter loading ratio assumptions, see U.S. Energy Information Administration*, Capital Cost Estimates and Performance Characteristics Estimates for Utility Scale Electricity Generating Technologies* (Washington, DC, January 2020), http://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

[6] *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.

[7] 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 .

[8] The one exception applies to the Salton Sea resource area, for which EIA used cost estimates provided in a 2010 report on electric power sector capital costs rather than NREL.

[9] Idaho National Laboratory, *The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems on the United States in the 21^{st} Century*. INL/EXT-06-11746 (Idaho Falls, ID 2006), http://geothermal.inel.gov/publications/future_of_geothermal_energy.pdf

[10]. U.S. Department of Energy, *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*, August 2011.

[11] Ibid

[12] De la Torre Ugarte, D., *Biomass and bioenergy applications of the POLYSYS modeling framework*. Biomass and Bioenergy, Vol. 18 (April 2000), pp. 291-308.

[13] U.S. Department of Energy, *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*, August 2011.

[14] U.S. Environmental Protection Agency, Atmospheric Pollution Prevention Division, Energy Project Landfill Gas Utilization Software (E-PLUS) Version 1.0, EPA-430-B-97-006 (Washington, DC, January 1997).

[15] U.S. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA- 0573(2003) (Washington, DC, December 2004), https://www.eia.gov/environment/emissions/archive/ghg/gg04rpt/index.html.

[16] Governmental Advisory Associates, Inc., METH2000 Database, Westport, CT, January 25, 2000.

[17] Hall, Douglas G., Richard T. Hunt, Kelly S. Reeves, and Greg R. Carroll, *Idaho National Engineering and Environmental Laboratory, Estimation of Economic Parameters of U.S. Hydropower Resources* INEEL/EXT-03-00662 (Idaho Falls, Idaho, June 2003), https://www1.eere.energy.gov/water/pdfs/doewater-00662.pdf

[18] Closed-loop biomass are crops produced explicitly for energy production. Open-loop biomass are generally wastes or residues that are a byproduct of some other process, such as crops grown for food, forestry, landscaping, or wood milling.

[19] U.S. Energy Information Administration, *Annual Energy Outlook 2016*, Legislation and Regulations LR3, DOE/EIA-0383(2016) (Washington, DC, August 2016), accessed September 23, 2016.