Renewable Fuels Module

The U.S. Energy Information Administration's (EIA) National Energy Modeling System (NEMS) Renewable Fuels Module (RFM) provides supply and technology inputs for natural resources. We use these inputs to project 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 depend largely on the EMM. The RFM also interacts with the Renewable Storage submodule (REStore) to estimate the impact of energy storage on the dispatch of generation and 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), 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 that use 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* 2021 (AEO2021) 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. 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, and heat from geothermal resources used directly (for example, district heating and greenhouses).

Capital costs

The EMM Assumptions document describes the methodology we used to determine initial capital costs and cost-learning assumptions. For AEO2020, an EIA consultant updated the current cost estimates for most utility-scale electric generating plants.[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 continued to use previously developed site-specific costs for those technologies. We also did not update costs for distributed generation plants in the power sector based on the consultant report, and input assumptions remain as in previous AEOs. We updated inputs for all other technologies listed in Table 2 starting in AEO2020.

Except as noted below, 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 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, 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 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 2020* report.

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 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 *Renewable Fuels Module of the National Energy Modeling System: Model Documentation 2020*, DOE/EIA-M069 (2020) Washington, DC, 2020.

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). Starting in AEO2021, we are including a combined solar PV and battery storage hybrid system as a generating technology option for capacity expansion.

Available solar capacity and its associated capacity factors are passed from the solar submodule in the RFM to the EMM for capacity planning and dispatch decisions. Based on these characteristics, the EMM decides 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 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 includes the same 150 MW array as the PV with single-axis tracking technology. Yet, it also includes a 50 MW/200 megawatthour (four-hour duration) lithium-ion battery storage system on the direct current (DC) side of a shared DC to alternating current (AC) inverter. The solar PV hybrid is represented through a simplified approach where a constant generation profile was created for each EMM region by inputting representative hourly regional electricity marginal prices into NREL's System Advisor Model (SAM).[4] We converted the hourly generation profiles derived from SAM to 12x24 capacity factor matrices for input into the RFM.

Cost

- Cost data for the single-axis tracking PV, solar PV hybrid, and concentrated solar power (CSP) systems used in NEMS are based on a report by Sargent & Lundy called *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies,* published in 2020.
- Even though the base cost in the Sargent & Lundy report for the solar PV hybrid technology represents an AC-coupled solar PV hybrid system, the EMM assumes the same capital cost for the modeled DC-coupled system. Limited empirical cost data show small differences in capital costs between similar AC and DC coupled systems,[5] but DC-coupled systems can take full advantage of investment tax credits available to solar generators.
- Regional cost adjustments reflect location-based cost adjustments in each EMM region for PV technology as provided by Sargent & Lundy.

Resources

- Available solar resources are reduced by excluding all lands not suited for solar installations, such as land used for non-intrusive 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, between 1.2 and 1.3).[6, 7] Increased ILRs introduce excessive solar clipping, where solar generation is lost by exceeding the inverter's rated output power. Since AEO2017, hawse 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.
- CSP technology is modeled 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

- NEMS represents the investment tax credit (ITC) that is available for qualified solar electric power generators as a percentage of the initial investment cost. In June 2018, the Internal Revenue Service (IRS) issued Notice 2018-59 to provide guidance for qualified solar plants. We assume 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
- We assume the solar PV hybrid system receives the full ITC as available. To be eligible for the ITC under current law (as of 2020), a storage system must receive at least 70% of its charging energy from a qualified solar generator. In a DC-coupled hybrid system as modeled, only the coupled solar generator can charge the battery, which ensures the system meets

the ITC criterion. Although AC-coupled hybrid systems may operate in a compliant manner, the current EIA model lacks the resolution to represent the necessary operational considerations.
- For utility-scale solar PV projects (both stand-alone and hybrid systems), we assume 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 Form EIA-860, *Annual Electric Generator Report,* and the 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 2022, 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 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.[8] 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 energy submodule in the RFM 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. Projections for distributed wind generation are included 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. However, 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, 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 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 they increase 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 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* explains these assumptions in greater 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) and is factored into requests for generating capacity by the EMM.
- The IRS issued Notice 2020-41 in May 2020, which allowed a five-year construction window for wind projects that began construction in 2016 and 2017 to address delays related to responses to COVID-19. In addition, the Taxpayer Certainty and Disaster Tax Relief Act of 2019 extended the production tax credit (PTC) for wind for an additional year at the 60% rate. We assume the phaseout of the PTC for wind projects as follows:

  - 80% of the current PTC value for projects that began construction in 2017 and enter service before 2023
  - 60% of the current PTC value for projects that began construction in 2018 and enter service before 2023
  - 40% of the current PTC value for projects that began construction in 2019 and enter service before 2024
  - 60% of the current PTC value for projects that began construction in 2020 and enter service before 2025
- The PTC is not available for projects that begin construction after December 31, 2020.
- As noted above, we assume 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.
- 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 includes planned capacity additions under construction or with an expected completion date before the end of 2022, according to respondents' planned completion dates.

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, we assumed that performance for a given annual average wind power density level is somewhat decreased by reduced turbine availability. Offsetting this challenge, however, is the availability of 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 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 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 EMM documentation.

Resources

- Like onshore wind resources, offshore wind resources are assumed to have an upward-sloping cost supply curve, which is 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 variation in terrain [in this case, seabed]).

Other

- Both onshore and offshore wind projects are eligible to claim the ITC in place of the PTC. Although we assume that onshore wind projects would choose the PTC, we assume 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 PTC phaseout schedule, as follows:
  - 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.[9, 10] We only consider resources with temperatures higher than 110 degrees Celsius. We use about 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,[11] 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 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. NREL provides a site-specific capital cost and 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%.

Assumptions

- The permanent ITC of 10% is available in all projection years, based on the Energy Policy Act of 1992 (EPACT92), and applies to all geothermal capital costs.

- 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 includes planned capacity additions under construction or that we expect to be completed before the end of 2022, 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 (the so-called captive capacity) as cogeneration. Generation in the electricity sector is represented in the EMM. Fuel costs are calculated in the RFM and are passed to the EMM, and capital and operating costs and performance characteristics are assumed 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 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.

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 (POLYSYS) agricultural model 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.[12] 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.[13]
- 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.[14] 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.[15] 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.

Other

- Biomass cofiring can occur up to a maximum of 15% of fuel used in coal-fired generating plants.
- 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 includes planned capacity additions under construction or that we expect to be completed before the end of 2022, according to respondents' planned completion dates.

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 in each EMM region. Starting in AEO2021, we model LFG generation facilities as primarily built to serve municipal waste disposal markets with secondary production of electric power (rather than as a capacity expansion option to the electric power industry). Based on 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

- Gross domestic product (GDP) and population are the drivers in an econometric equation that establishes the supply of landfill gas.
- We use EPA's Landfill Methane Outreach Program (LMOP) landfill database[16] to determine available methane resources (in tonnage and five-year increments) and project development timelines. We assume LMOP's *Candidate* landfills for new landfills, and the model uses *Probable* landfills only if it has exhausted the potential from *Candidate* landfills.

Other

- 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 includes planned capacity additions under construction or that we expect to be completed before the end of 2022, 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 and both undeveloped sites and sites with existing dam, diversion, or generating facilities.
- The supply excludes pumped storage hydroelectric, but we do model the operation of existing pumped hydro facilities.
- 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

- We estimate costs 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, 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

- 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 the supply includes only sites with estimated costs of 10 cents per kilowatthour (kWh) or lower.
- The RFM incorporates the extended PTC expiration date for any qualified facilities and qualified incremental hydroelectric generation as enacted by the law and its various extensions. These facilities can claim the tax credit on generation sold during their first 10 years of operation.
- 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 includes planned capacity additions under construction or that we expect to be completed before the end of 2022, according to respondents' planned completion dates.

Renewable Storage (REStore) submodule

In AEO2019, we introduced a new submodule within the EMM to provide the additional details needed to represent renewable availability at a greater level of detail beyond the nine time slices used by most other EMM submodules. 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 model 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. We aggregate the results back to the nine time slices for input to the other submodules of the EMM. The REStore submodule incorporates improved representation of hydroelectric 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 load slice dispatch of the Electricity Capacity Planning submodule and the Electricity Fuel Dispatch submodule. Because it includes hourly level dispatch, REStore represents the costs and 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 operating and maintenance costs. Although this approach assumes the EMM regions are separate problems, 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 tax credit (ITC) and production tax credit (PTC) codified in EPACT92 and as amended.

The ITC provides a credit to federal income tax liability as a percentage of the initial investment cost for a qualified renewable and storage generating facility. In June 2018, the IRS issued Notice 2018-59, which gave 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 utility-scale solar plants (stand-alone and hybrid systems)—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. Unlike solar PV hybrid systems, stand-alone utility-scale energy storage systems are assumed to be ineligible for the ITC because the system is not guaranteed by the model to be charged by renewable sources. 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. The CDM and RDM reflect this change.

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 AEO2021, wind resources receive a tax credit of 2.5 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). We assume that biomass facilities obtaining the PTC will use open-loop fuels[18] because we also assume that closed-loop fuels are unavailable or too expensive for widespread use during the period the tax credit is available. The PTC has been most recently extended in the Taxpayer Certainty and Disaster Tax Relief Act of 2019, Division Q of the Further Consolidated Appropriations Act of 2020. This act extended the phaseout schedule as amended by the Consolidated Appropriations Act of 2016 by one year. Given the IRS Notice 2020-41, we assume the PTC to phasedown:

- 80% of the current PTC if it began construction in 2017 and is operating before 2023
- 60% of the current PTC if it began construction in 2018 and is operating before 2023
- 40% of the current PTC if it began construction in 2019 and is operating before 2024
- 60% of the current PTC if it begins construction in 2020 and is operating before 2025

Both onshore and offshore wind projects are eligible to claim the ITC in place of the PTC. Although we expect onshore wind projects to choose the PTC, we assume 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 the same facility cannot claim both.

Further details on the PTC and ITC modeling assumptions are available 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*.[19]

State-level requirements for offshore wind and battery storage

AEO2021 includes states that have specified installed capacity requirements for offshore wind and diurnal battery storage. A more detailed list of state requirements for offshore wind and diurnal battery storage is included in the Legislation and Regulations document for AEO2021.

State renewable portfolio standards programs

We included various state-level policies that require renewable generation to increase to meet a minimum share of statewide generation, generally referred to as renewable portfolio standards (RPS) (Table 1). These policies vary significantly by state. AEO2021 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. 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, the compliance rate is an estimate.

Table 1. Aggregate state renewable portfolio standards requirements (billion kilowatthours, millions of renewable energy credits)

State	2021	2030	2040	2050
Arizona	6.5	9.8	10.8	12.3
California	81.6	152.0	233.8	303.1
Colorado	10.0	11.2	12.4	14.2
Connecticut	7.1	12.2	12.9	14.1
Delaware	2.1	2.7	2.8	3.1
District of Columbia	2.8	9.8	12.0	13.2
Illinois	17.0	25.8	27.4	29.8
Iowa	0.3	0.3	0.3	0.3
Maine	2.4	5.4	9.1	13.7
Maryland	19.1	32.3	34.3	37.6
Massachusetts	9.9	19.0	25.5	33.7
Michigan	14.9	15.8	16.8	18.2
Minnesota	16.9	19.8	21.1	23.0
Missouri	8.1	8.6	9.2	10.0
Montana	1.1	1.2	1.3	1.4
Nevada	7.1	20.7	34.6	53.0
New Hampshire	2.2	2.7	2.8	3.1
New Jersey	22.0	41.4	43.0	47.2
New Mexico	5.4	13.1	23.2	32.8
New York	33.6	100.2	148.9	161.8
North Carolina	15.4	17.0	18.5	20.6
Ohio	7.6	11.6	12.4	13.5
Oregon	7.6	13.9	20.0	22.5
Pennsylvania	25.0	26.8	28.4	31.1
Rhode Island	1.2	2.3	3.0	3.2
Texas	15.5	16.1	16.1	16.2
Vermont	3.0	3.8	4.2	4.6
Virginia	13.9	47.8	102.0	148.9
Washington	11.9	21.8	44.1	93.2
Wisconsin	6.5	6.9	7.4	8.1

Source: Various state laws and regulations as implemented in the *Annual Energy Outlook 2021* (AEO2021). AEO2021 only considered policies signed into law as of October 1, 2020; 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 Renewables & Efficiency.

We estimate regional renewable generation targets by 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 to determine a regional renewable generation share of total sales.

The calculation includes only targets with established enforcement provisions or established state funding mechanisms; it does not include non-enforceable goals. Compliance enforcement provisions vary significantly across states, and most states have established procedures for waiving compliance through 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.

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] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, Sargent & Lundy, December 2019, 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, 2018, "The National Solar Radiation Data Base (NSRDB)." *Renewable and Sustainable Energy Reviews* 89 (June): 51-60.

[4] National Renewable Energy Laboratory System Advisor Model, https://sam.nrel.gov/.

[5] Fu, Ran, Timothy Remo, and Robert Margolis. 2018. 2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf.

[6] 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.

[7] 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.

[8] *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.

[9] 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 .

[10] 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.

[11] 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.

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

[13] Ibid.

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

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

[16] U.S. Environmental Protection Agency, Landfill Methane Outreach Program (LMOP).

[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.