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)
- 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 the EMM is highly integrated with the RFM, 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 not only the impact of energy storage on dispatching generation, 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), which contains additional representation of some 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 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 electricity 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 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* 2022 (AEO2022) 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 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, and 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 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 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 broken out 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, 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, 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-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 Activity Module of NEMS. Independent of the other two factors, we assume capital costs for all electric generation 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 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). Since AEO2021, we have included 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. 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. Solar PV hybrid only requires a more 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 as input for the RFM (that is, typical hourly generation for each month of the year).

Cost

- We base cost data for the single-axis tracking PV, solar PV hybrid, and concentrated solar power (CSP) systems used in NEMS 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 are eligible for investment tax credits (ITC) 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

- 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.[6, 7] 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

- NEMS represents the ITC that is available for qualified solar electric power generators as a percentage of the initial investment cost. The Taxpayer Certainty and Disaster Tax Relief Act of 2020, passed in December 2020, extends the previous phasedown of the ITC by two years. Along with the Internal Revenue Service (IRS) Notice 2021-41, we assume the following in AEO2022:
    - 26% tax credit for projects starting construction by 2022 and entering service before January 1, 2026
    - 10% tax credit for projects entering service after December 31, 2025
- We assume the solar PV hybrid system receives the full ITC as available. To be eligible for the ITC under current law (as of 2021), 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 compliance, our current 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 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 2023, 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.[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. 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. 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
  - 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* 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) and is factored into requests for generating capacity by the EMM.
- To address delays related to responses to COVID-19, the IRS issued Notice 2021-41 in June 2021, which allowed a five-year construction window for wind projects that began construction in 2016 through 2020, along with the Taxpayer Certainty and Disaster Tax Relief Act of 2020 passed in December 2020. We assume the phaseout of the PTC for wind projects in AEO2022 is 60% of the current PTC value for projects that began construction by December 31, 2021, and enter service before 2026
- The PTC is not available for projects that enter service after December 31, 2025.

- As previously noted, 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 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 2023, 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 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

- As with onshore wind resources, we assume offshore wind resources have an upward-sloping cost supply curve, which is affected primarily by water depth but also 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]).

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 Taxpayer Certainty and Disaster Tax Relief Act of 2020, passed in December 2020, allows offshore wind projects to claim the ITC at the full 30% for projects beginning construction by December 31, 2025, and placed in service no later than December 31, 2035.

Geothermal Electricity Submodule

Background

We base the geothermal supply curve data on NREL's updated U.S. geothermal supply curve assessment, which uses 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°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,[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 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, however. 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

- The permanent ITC of 10% is available in all projection years, based on the Energy Policy Act of 1992 (EPACT1992), and applies to all geothermal capital costs.
- 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 2023, 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 represented is 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.[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 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 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 2022, 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 secondary production of electric power (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 an econometric equation that establishes the LFG supply.
- 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 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 2023, 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, but we 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.

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).[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

- 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.
- 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.
- 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 2023, 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 periods 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 module with 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 periods 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 module with 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 PTCs initiated in EPACT1992 and amended in EPACT2005 have been further amended through a series of acts that have been implemented in NEMS over time. AEO2022 continues to reflect the most recent changes implemented through the Taxpayer Certainty and Disaster Tax Relief Act of 2020 (TCDRT). Along with Continuity Safe Harbor guidance from the IRS, AEO2022 assumes a 26% ITC for all solar plants online by 2025. The ITC drops to 10% for plants coming online after 2025.

The PTC is a per-kilowatthour tax credit originally available for qualified wind, geothermal, closed-loop and open-loop biomass, LFG, municipal solid waste, hydroelectric, and marine and hydrokinetic facilities. The value of the credit, originally 1.5 cents/kWh, is adjusted for inflation annually and is available for 10 years after the facility has been placed in service but is subject to phaseout schedules as implemented by recent amendments. The TCDRT extended the wind PTC phaseout by one year, and AEO2022 assumes 60% of the current PTC value is available for all wind plants that began construction by December 31, 2021, and are online through 2025.

The ITCs and PTCs are exclusive of one another, and the same facility cannot claim both. We assume that new geothermal plants choose the 10% ITC. Both onshore and offshore wind projects are eligible to claim the ITC instead of the PTC. Although we expect onshore wind projects to choose the PTC, we assume offshore wind farms will claim the ITC because of the high capital costs for offshore wind. The TCRDT allows offshore wind projects to claim the full 30% ITC for projects under construction by December 31, 2025, and placed in service no later than December 31, 2035.

State-level requirements for offshore wind and battery storage

AEO2022 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 *Summary of Legislation and Regulations Included in the Annual Energy Outlook 2022* report.

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. AEO2022 includes technology-specific requirements, 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	2022	2030	2040	2050
Arizona	7.33	9.83	10.80	12.00
California	81.17	153.42	233.57	292.02
Colorado	10.52	11.26	12.40	13.82
Connecticut	7.55	12.41	13.06	14.14
Delaware	2.29	3.29	4.96	5.40
District of Columbia	3.55	9.83	11.92	12.99
Illinois	18.56	25.51	26.72	28.53
Iowa	0.32	0.31	0.31	0.32
Maine	2.68	5.39	9.08	13.52
Maryland	20.89	32.22	33.99	36.97
Massachusetts	1.99	2.08	2.18	2.37
Michigan	15.03	15.72	16.44	17.55
Minnesota	1.92	1.95	2.06	2.20
Missouri	8.11	8.29	8.75	9.39
Montana	1.18	1.23	1.31	1.42
Nevada	8.58	20.28	56.15	75.34
New Hampshire	2.33	2.73	2.87	3.11
New Jersey	7.43	3.33	1.75	1.91
New Mexico	6.61	13.69	24.16	33.48
New York	42.06	100.63	148.64	160.32
North Carolina	15.75	16.86	18.35	20.38
Ohio	8.35	11.53	12.17	13.11
Oregon	14.38	33.21	45.53	49.55
Pennsylvania	1.55	1.61	1.69	1.85
Rhode Island	1.35	2.30	3.01	3.26
Texas	16.27	16.48	16.43	16.35
Vermont	3.10	3.90	4.33	4.69
Virginia	17.48	48.18	102.79	149.09
Washington	13.14	22.89	45.79	93.68
Wisconsin	6.83	6.95	7.32	7.84

Source: Various state laws and regulations as implemented in the *Annual Energy Outlook 2022* (AEO2022). AEO2022 only considered policies signed into law as of October 1, 2021; state policies signed into law after that date are not included for AEO2022. For a more complete overview of specific state targets, along with links to current controlling policies and regulatory actions, see the National Conference of State Legislatures State Renewable Portfolio Standards and Goals.

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] 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] Fu, Ran, Timothy Remo, and Robert Margolis, "2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark." Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714 (November 2018), 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.
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[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 we used cost estimates provided in a 2010 report on electric power sector capital costs rather than NREL.
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[12] U.S. Department of Energy, *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*, August 2011.
[13] U.S. Department of Energy, *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*, August 2011.
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[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.