Renewable Fuels Module

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The NEMS Renewable Fuels Module (RFM) provides natural resources supply and technology input information for projections of new central-station U.S. electricity generating capacity using renewable energy resources. The RFM has seven submodules representing various renewable energy sources: biomass, geothermal, conventional hydroelectricity, landfill gas, solar thermal, solar photovoltaics, and wind [1].

Some renewables, such as landfill gas (LFG) from municipal solid waste (MSW) and other biomass materials, are fuels in the conventional sense of the word, while others, such as water, wind, and solar radiation, are energy sources that do not involve the production or consumption of a fuel. Commercial market penetration of renewable technologies varies widely. Hydroelectric power, one of the oldest electric generation technologies, accounted for roughly 8 percent of electric power generation in 2011; newer power systems using biomass, geothermal, LFG, solar, or wind energy contribute a combined 5 percent.

The submodules of the RFM interact primarily with the Electricity Market Module (EMM). 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 upon the EMM. Because some types of biomass fuel can be used for either electricity generation or for the production of liquid fuels, such as ethanol, there is also some interaction with the Petroleum Market Module (PMM), 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 not in the RFM; see the Distributed Generation and Combined Heat and Power description in the "Commercial Demand Module" and "Residential Demand Module" sections of the report. Descriptions for biomass energy production in industrial settings, such as the pulp and paper industries can be found in the "Industrial Demand Module" section of the report..

Key assumptions

Nonelectric renewable energy uses

In addition to projections for renewable energy used in central station electricity generation, AEO2013 contains projections of nonelectric renewable energy uses for industrial and residential wood consumption, 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 found in the residential, commercial, industrial, and petroleum marketing module sections of this report. Additional minor renewable energy applications occurring outside energy markets, such as direct solar thermal industrial applications or direct lighting, off-grid electricity generation, and heat from geothermal resources used directly (e.g., district heating and greenhouses) are not included in the projections.

Electric power generation

The RFM considers only grid-connected central station electricity generation systems. The RFM submodules that interact with the EMM are the central station grid-connected biomass, geothermal, conventional hydroelectricity, landfill gas, solar (thermal and photovoltaic), and wind submodules, which provide specific data or estimates that characterize the respective resource. A set of technology cost and performance values is provided directly to the EMM and is central to the build and dispatch decisions of the EMM. The technology cost and performance values are summarized in Table 8.2 in the chapter discussing the EMM.

Capital costs

Capital costs for renewable technologies are affected by several factors. Capital costs for technology to exploit some resources, especially geothermal, hydroelectric, and wind power resources, are assumed to be dependent on the quality, accessibility, and/or other site-specific factors in the areas with exploitable resources. These factors can include additional costs associated with reduced resource quality; need to build or upgrade transmission capacity from remote resource areas to load centers; or local impediments to permitting, equipment transport, and construction in good resource areas due to siting issues, inadequate infrastructure, or rough terrain.

Short-term cost adjustment factors increase technology capital costs as a result of a rapid U.S. buildup in a single year, reflecting limitations on the infrastructure (for example, limits on manufacturing, resource assessment, and construction expertise) to accommodate unexpected demand growth. 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 Report, available at www.eia.gov/analysis/model-documentation.cfm.

Also assumed to affect all new capacity types are costs associated with construction commodities. Through much of the period from 2000 to 2008, the installed cost for most new plants was observed to increase. Although several factors contributed to this cost escalation, some of which may be more or less important to specific types of new capacity, much of the overall cost increase was correlated with increases in the cost of construction materials, such as bulk metals, specialty metals, and concrete. 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 lowering generating technologies' capital costs as more units enter service (learning), see "Technological Optimism and Learning" in the EMM chapter of this report. A detailed description of the RFM is provided in the EIA publication, Renewable Fuels Module of the National Energy Modeling System, Model Documentation 2011, DOE/EIA-M069(2011) (Washington, DC, 2011).

Solar Electric Submodule

Background

The Solar Electric Submodule currently includes both solar thermal (also referred to as "concentrating solar power" or CSP) and photovoltaic (PV), technologies. The representative solar thermal technology assumed for cost estimation is a 100-megawatt central-receiver tower without integrated energy storage, while the representative solar PV technology is a 150-megawatt array of flat plate PV modules using single-axis tracking. PV is assumed available in all EMM regions, while CSP is available only in the Western regions with the arid atmospheric conditions that result in the most cost-effective capture of direct sunlight. Cost estimates for both technologies are based on a forthcoming report by SAIC to be published in early 2013, see: the "Documentations & Assumptions" section of www.eia.gov/forecasts/aeo/er/index.cfm). Technology- specific performance characteristics are obtained from information provided by the National Renewable Energy Laboratory (NREL).

Assumptions

- NEMS represents the Energy Policy Act of 1992 (EPACT92) permanent 10-percent investment tax credit (ITC) for solar electric power generation by tax-paying entities. In addition, the current 30-percent ITC, scheduled to expire at the end of 2016, is also represented to qualifying new capacity installations.
- Existing capacity and planned capacity additions are based on EIA survey data from the Form EIA-860, "Annual Electric Generator Report" and Form EIA-860M, "Monthly Update to the Annual Electric Generator Report". Planned capacity additions under construction or having all regulatory approvals and having an expected completion date prior to the expiration of the 30-percent ITC were included in the model's planned capacity additions, according to respondents' planned completion dates.
- Capacity factors for solar technologies are assumed to vary by time of day and season of the year, such that nine separate capacity factors are provided for each modeled region, three for time of day and for each of three broad seasonal groups (summer, winter, and spring/fall). Regional capacity factors vary from national averages based on climate and latitude.
- Solar resources are well in excess of conceivable demand for new capacity; energy supplies are considered unlimited within regions (at specified daily, seasonal, and regional capacity factors). Therefore, solar resources are not estimated in NEMS. In the regions where CSP technology is not modeled, the level of direct, normal insolation (the kind needed for that technology) is assumed to be insufficient to make that technology commercially viable through the projection horizon.

Wind-Electric Power Submodule

Background

Because of limits to windy land areas, wind is considered a finite resource, so the submodule calculates maximum available capacity by Electricity Market Module Supply Regions. The minimum economically viable average wind speed is about 15 mph at a hub-height of 80 m, and wind speeds are categorized by annual average wind speed based on a classification system originally from the Pacific Northwest Laboratory (see http://rredc.nrel.gov/wind/pubs/atlas/tables/1-1T.html). The RFM tracks wind capacity (megawatts) 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 the National Renewable Energy Laboratory [2]. The technological performance, cost, and other wind data used in NEMS are based on a forthcoming report by SAIC to be published in early 2013, see: the "Documentations & Assumptions" section of www.eia.gov/forecasts/aeo/er/index.cfm). Maximum wind capacity, capacity factors, and incentives are provided to the EMM for capacity planning and dispatch decisions. These form the basis on which the EMM decides how much power generation capacity is available from wind energy. The fossil-fuel heat rate equivalents for wind are used for energy consumption calculation purposes only.

Assumptions

- Only grid-connected (utility and nonutility) generation is included. Projections for distributed wind generation are included in the commercial and residential modules.
- In the wind submodule, wind supply costs are affected by three modeling measures addressing: (1) average wind speed, (2) distance from existing transmission lines, and (3) resource degradation, transmission network upgrade costs, and market factors.
- Available wind resource is reduced by excluding all windy lands not suited for the installation of wind turbines because of: excessive terrain slope (greater than 20 percent); reservation of land for non-intrusive uses (such as National Parks, wildlife refuges, and so forth); inherent incompatibility with existing land uses (such as urban areas, areas surrounding airports and water bodies, including offshore locations); 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 resource 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 uncertain ability to site projects at such locations. These assumptions are detailed in the Draft Final Report to EIA titled, "Incorporation of Existing Validated Wind Data into NEMS," November 2003.
- Capital costs for wind technologies are assumed to increase in response to (1) 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 utilized, (2) increasing cost of upgrading existing local and network distribution and transmission lines to accommodate growing quantities of remote wind power, and (3) 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 percent, and finally 100 percent, to represent the aggregation of these factors
- Proportions of total wind resources in each category vary by EMM region. For all EMM regions combined, about 1 percent of windy land (107 GW of 11,600 GW in total resource) is available with no cost increase, 3.4 percent (390 GW) is available with a 10 percent cost increase, 2 percent (240 GW) is available with a 25-percent cost increase, and over 90 percent is available with a 50- or 100-percent cost increase.
- Depending on the EMM region, the cost of competing fuels, and other factors, wind plants can be built to meet system capacity requirements or as a "fuel saver" to displace generation from existing capacity. For wind to penetrate as a fuel saver, its total capital and fixed operations and maintenance costs minus applicable subsidies must be less than the variable operating costs, including fuel, of the existing (non-wind) capacity. When competing in the new capacity market, wind is assigned a capacity credit that declines based on its estimated contribution to regional reliability requirements.
- 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 megawatts per square kilometer of windy land, and is factored into requests for generating capacity by the EMM.
- Capacity factors for each wind class are calculated as a function of overall wind market growth. The capacity factors are assumed to be limited to about 50 percent for a typical Class 6 site. As better wind resources are depleted, capacity factors are assumed to go down, corresponding with the use of less desirable sites. By 2040, the typical wind plant build will have a somewhat lower capacity factor than those found in the best wind resource areas. Capacity factors in the Reference case increase to about 45 percent in the best wind class resulting from taller towers, more reliable equipment, and advanced technologies, although, as noted, these may not represent the best available sites because of other site-specific factors.

- *AEO2013 does not allow plants constructed after 2012 to claim the federal Production Tax Credit (PTC), a 2.2-cent-per-kilowatt- hour tax incentive for wind that wasset to expire on December 31, 2012 for wind only. After completion of this case, the law was changed to allow wind plants under construction by December 31, 2013 to qualify for the PTC. Wind plants are assumed to depreciate capital expenses using the Modified Accelerated Cost Recovery Schedule with a 5-year tax life*.

Offshore wind resources are represented as a separate technology from onshore wind resources. Offshore resources are modeled with a similar model structure as onshore wind. However, because of the unique challenges of offshore construction and the somewhat different resource quality, the assumptions with regard to capital cost, learning-by-doing cost reductions, and variation of resource exploitation costs and performance differ significantly from onshore wind..

- Like onshore resources, offshore resources are assumed to have an upwardly sloping supply curve, in part influenced by the same factors that determine the onshore supply curve (such as distance to load centers, environmental or aesthetic concerns, variable terrain/seabed) but also explicitly by water depth.
- Because of the more difficult maintenance challenge offshore, performance for a given annual average wind power density level is assumed to be somewhat reduced by reduced turbine availability. Offsetting this, however, is the availability of resource areas with higher overall power density than is assumed available onshore. Capacity factors for offshore are limited to be about 50 percent for a Class 7 site.
- 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 on-shore technology. A technological optimism factor (see EMM documentation: www.eia.gov/ analysis/model-documentation.cfm) is included for offshore wind to account for the substantial cost of establishing the unique construction infrastructure required for this technology.

Geothermal-Electric Power Submodule

Background

Beginning in AEO2011, all geothermal supply curve data came from the National Renewable Energy Laboratory's updated U.S. geothermal supply curve assessment. The report, released in February 2010, assigns cost estimates to the U.S. Geological Survey's (USGS) 2008 geothermal resource assessment. Some data from the 2006 report, "The Future of Geothermal Energy," prepared by the Massachusetts Institute of Technology, was also incorporated into the NREL report; however, this would be more relevant to deep, dry, and unknown geothermal resources, something which EIA did not include in its supply curve. NREL took the USGS data and used the Geothermal Electricity Technology Evaluation Model (GETEM), an Excel-based techno-economic systems analysis tool, to estimate the costs [3]. Only resources with temperatures above 110 degrees Celsius were considered. There are approximately 125 of these known, hydrothermal resources which EIA used in its supply curve. Each of these sites also has what NREL classified 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. Therefore, there are 250 total points on the supply curve since each of the 125 hydrothermal sites has corresponding enhanced geothermal system (EGS) potential.

In the past, EIA cost estimates were broken down into cost-specific components. Unfortunately, this level of detail was not available in the NREL data. A site-specific capital cost and fixed operations and maintenance cost were provided. Both types of technology, both flash and binary, are also included with capacity factors ranging from 90 to 95 percent. While the source of the data was changed beginning in AEO2011, the site-by-site matrix input that acts as the supply curve has been retained.

Assumptions

- Existing and identified planned capacity data are obtained directly by the EMM from Form EIA-860 and Form EIA-860m.
- The permanent investment tax credit of 10 percent available in all projection years, based on the EPACT, applies to all geothermal capital costs, except through December 2013 when the 2.2-cent production tax credit is available to this technology and is assumed chosen instead. Projects that have begun construction and are beyond the exploratory drilling phase by that date are eligible for this production tax credit.
- Plants are not assumed to retire unless their retirement is reported to EIA. The Geysers units are not assumed to retire but instead are assigned the 35-percent capacity factors reported to EIA reflecting their reduced performance in recent years.

Biomass Electric Power 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 industrial sector module as cogeneration. Generation in the electricity sector is represented in the EMM. Fuel costs are calculated in NEMS and passed to EMM, while capital and operating costs and performance characteristics are assumed as shown in Table 8.2. Fuel costs are provided in sets of regional supply schedules. Projections for ethanol are produced by the Petroleum Market Module (PMM), with the quantities of biomass consumed for ethanol decremented from, and prices obtained from, the EMM regional supply schedules.

Assumptions

- Existing and planned capacity data are obtained from Form EIA-860 and Form EIA-860m.
- The conversion technology represented is an 80-MW dedicated combustion plant. The cost estimates for this technology are based on a forthcoming report by SAIC to be published in early 2013, see: the "Documentations & Assumptions" section of www.eia.gov/forecasts/aeo/er/index.cfm).
- Biomass co-firing can occur up to a maximum of 15 percent of fuel used in coal-fired generating plants

Fuel supply schedules are a composite of four fuel types: forestry materials, wood residues, 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 prices as the rest of NEMS. Forestry residues are calculated from inventories conducted by the U.S. Forest Service and Oak Ridge National Laboratory. The forestry materials component is made up of logging residues, rough rotten salvageable dead wood, and excess small pole trees.[4] 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 [5]. Agricultural residues are wheat straw, corn stover, and a number of other major agricultural crops [6]. Energy crop data are for hybrid poplar, willow, and switchgrass grown on existing cropland. POLYSYS assumes that the additional cropland needed for energy crops will displace existing pasturelands. The lands in the Conservation Reserve Program are preserved [7]. The maximum amount of resources in each coal region is shown in Table 13.1.

Table 13.1. Maximum U.S. biomass resources, by coal demand region and type in 2035
trillion Btu

Coal Demand Region	States	Agricultural Sector	Forestry Residue	Urban Wood Waste/Mill Residue
1 (NE)	CT, MA, ME, NH, RI, VT	6	115	40
2 (YP)	NY, PA, NJ	164	162	88
3 (S1)	WV, MD, DC, DE	174	91	37
4 (S2)	VA, NC, SC	167	364	58
5 (GF)	GA, FL	104	358	87
6 (OH)	OH	266	60	37
7 (EN)	IN, IL, MI, WI	1323	155	81
8 (KT)	KY, TN	353	167	43
9 (AM)	AL, MS	194	332	43
10 (C1)	MN, ND, SD	279	57	31
11 (C2)	IA, NE, MO, KS	2183	77	45
12 (WS)	TX, LA, OK, AR	689	269	86
13 (MT)	MT, WY, ID	78	61	26
14 (CU)	CO, UT, NV	32	59	51
15 (ZN)	AZ, NM	12	73	41
16 (PC)	AK, HI, WA, OR, CA	84	239	122

Sources: U.S. Billion-Ton Update (Oak Ridge National Lab, 2011) and the Policy Analysis (POLYSYS) model developed by the University of Tennessee's Department of Agricultural Economics.

Landfill-Gas-to-Electricity 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 gas collection system and electricity generator costs and characteristics developed by EPA's "Energy Project Landfill Gas Utilization Software" (E-PLUS) [8] .

Assumptions

- Gross domestic product (GDP) and population are used as the drivers in an econometric equation that establishes the supply of landfill gas.
- Recycling is assumed to account for 50 percent of the waste stream in 2010 (consistent with EPA's recycling goals).
- The waste stream is characterized into three categories: readily, moderately, and slowly decomposable material.
- 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 [9].
- The ratio of "high," "low," and "very low" methane production sites to total methane production is calculated from data obtained for 156 operating landfills contained in the Government Advisory Associates METH2000 database [10].
- Cost-of-electricity for each site was calculated by assuming each site to be a 100-acre by 50-foot deep landfill and by applying methane emission factors for "high," "low," and "very low" methane emitting wastes.

Conventional hydroelectricity

The conventional hydroelectricity submodule represents U.S. potential for new conventional hydroelectric capacity of 1 megawatt or greater from new dams, existing dams without hydroelectricity, and from adding capacity at existing hydroelectric dams. 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, plus estimates of capital and other costs prepared by the Idaho National Engineering and Environmental Laboratory (INEEL) [11]. Annual performance estimates (capacity factors) were taken from the generally lower but site-specific FERC estimates rather than from the general estimates prepared by INEEL, and only sites with estimated costs of 10 cents per kilowatthour or lower are included in the supply. Pumped storage hydro, considered a nonrenewable storage medium for fossil and nuclear power, is not included in the supply; moreover, the supply does not consider offshore or in-stream hydro, efficiency or operational improvements without capital additions, or additional potential from refurbishing existing hydroelectric capacity.

In the hydroelectricity submodule, sites are first arrayed by NEMS region from least to highest cost per kilowatthour. For any year's capacity decisions, only those hydroelectric sites whose estimated levelized costs per kilowatthour are equal to or less than an EMM-determined avoided cost (the least cost of other technology choices determined in the previous decision cycle) are submitted. Next, the array of below-avoided-cost sites is parceled into three increasing cost groups, with each group characterized by the average capacity-weighted cost and performance of its component sites. Finally, the EMM receives from the conventional hydroelectricity submodule the three increasing-cost quantities of potential capacity for each region, providing the number of megawatts potential along with their capacity-weighted average overnight capital cost, operations and maintenance cost, and average capacity factor. After choosing from the supply, the EMM informs the hydroelectricity submodule, which decrements available regional potential in preparation for the next capacity decision cycle.

Legislation and regulations

Renewable electricity tax credits

The RFM includes the investment and energy production tax credits codified in the Energy Policy Act of 1992 (EPACT92) as amended. The investment tax credit established by EPACT92 provides a credit to Federal income tax liability worth 10 percent of initial investment cost for a solar, geothermal, or qualifying biomass facility. This credit was raised to 30 percent through 2016 for some solar projects and extended to residential projects. This change is reflected in the RFM, commercial demand, and residential demand modules. The production tax credit, as established by EPACT92, applied to wind and certain biomass facilities. As amended, it provides a 2.2-cent tax credit for every kilowatthour of electricity produced for the first 10 years of operation for a wind facility constructed by December 31, 2012 or by December 31, 2013 for other eligible facilities. The value of the credit, originally 1.5 cents, is adjusted annually for inflation. With the various amendments, the production tax credit is available for electricity produced from qualifying geothermal, animal waste, certain small-scale hydroelectric, landfill gas, municipal solid waste, and additional biomass resources. Wind, poultry litter, geothermal, and "closed loop" [12] biomass resources receive a

2.2-cent tax credit for the first 10 years of facility operations. All other renewable resources receive a 1.1 cent (that is, one-half the value of the credit for other resources) tax credit for the first 10 years of facility operations. EIA assumes that biomass facilities obtaining the PTC will use “open-loop” fuels, as “closed-loop” fuels are assumed to be unavailable and/or too expensive for widespread use during the period that the tax credit is available. The investment and production tax credits are exclusive of one another, and may not both be claimed for the same geothermal facility (which is eligible to receive either.

The American Taxpayer Relief Act passed in January of 2012 extends the wind PTC expiration date until December 31, 2013. In addition, it modifies the requirement for all fuels that plants be operational by the expiration date to allow any plant under construction by the expiration date to qualify. However, due to the timing of the legislation, this update is not included in the AEO2013 Reference case.

State RPS programs

EIA represents various State-level policies generally referred to as Renewable Portfolio Standards (RPS). These policies vary significantly among States, but typically require the addition of renewable generation to meet a specified share of State-wide generation.   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 nature of some of the limitations, the measurement of compliance is assumed to be approximate.

Regional renewable generation targets were estimated using the renewable generation targets in each State within the region. In many cases, regional boundaries intersect State boundaries; in these cases State requirements were divided among relevant regions based on sales. Using State-level RPS compliance schedules and preliminary estimates of projected sales growth, EIA estimated the amount of renewable generation required in each State within a region. 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, as shown in Table 13.2.

Only targets with established enforcement provisions or established State funding mechanisms were included in the calculation; Non-enforceable goals were not included.. Compliance enforcement provisions vary significantly among 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.

Alternative renewable case

Low Renewable Cost case

The Low Renewable Cost case examines the effect of reducing renewable technology capital costs by 20 percent below Reference case values throughout the projection period.

For wind, biomass, LFG, geothermal, and solar technologies, this cost reduction is achieved by a applying a 20% reduction in the base overnight capital costs assumed in the Reference case. For geothermal and hydro, the capital cost of each individual site that is modeled is reduced by 20% compared to the Reference case.   Biomass prices are also assumed to be reduced 20 percent for a given quantity of fuel supplied. Other assumptions within NEMS are unchanged from the Reference case.

For the Low Renewable Cost case, demand-side improvements are also assumed in the renewable energy technology options of residential demand, commercial demand, industrial demand, and PMM modules. Details on these assumptions can be found in the corresponding sections of this report.

Table 13.2. Aggregate regional renewable portfolio standard requirements (percentage share of total values)

Region[1]	2020	2030	2040
Texas Reliability Entity	4.4%	4.4%	4.4%
Midwest Reliability Council - East	10.0%	10.0%	10.0%
Midwest Reliability Council - West	10.3%	11.4%	11.4%
Northeast Power Coordinating Council - Northeast	14.3%	14.6%	14.6%
Northeast Power Coordinating Council - NYC/Westchester	24.6%	24.6%	24.6%
Northeast Power Coordinating Council - Long Island	24.6%	24.6%	24.6%
Northeast Power Coordinating Council - Upstate NY	24.4%	24.5%	24.5%
Reliability First Corporation - East	13.6%	14.8%	14.8%
Reliability First Corporation - Michigan	10.0%	10.0%	10.0%
Reliability First Corporation - West	7.1%	9.3%	9.3%
SERC Reliability Corporation - Delta	0.6%	0.6%	0.6%
SERC Reliability Corporation - Gateway	11.2%	15.8%	15.8%
SERC Reliability Corporation - Virginia/Carolina	0.0%	0.1%	0.1%
SERC Reliability Corporation - Virginia/Carolina	5.0%	5.6%	5.5%
Southwest Power Pool - North	11.9%	13.2%	13.2%
Southwest Power Pool - South	2.1%	2.2%	2.2%
Western Electricity Coordinating Council - Southwest	9.4%	11.1%	11.1%
Western Electricity Coordinating Council - California	33.0%	33.0%	33.0%
Western Electricity Coordinating Council - Northwest	10.1%	11.0%	11.0%
Western Electricity Coordinating Council - Rockies	15.5%	15.5%	15.5%

[1] See chapter on the Electricity Market Module for a map of the electricity market module supply regions.

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(2011), (Washington, DC, August 2011).

[2] 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.

[3] The one exception applies to the Salton Sea resource area. For that site, EIA used cost estimates provided by R.W. Beck, Inc. rather than NREL.

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

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

[6] De la Torre Ugarte, D. "Biomass and bioenergy applications of the POLYSYS modeling framework" Biomass and Bioenergy 18 (2000): 291-308.

[7] De la Torre Ugarte, D. "Biomass and bioenergy applications of the POLYSYS modeling framework" Biomass and Bioenergy 18 (2000): 291-308.

[8] 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).

[9] U.S. Energy Information Administration, "Emissions of Greenhouse Gases in the United States 2003", DOE/EIA-

0573(2003) (Washington, DC, December 2004), www.eia.gov/oiaf/1605/archive/gg04rpt/index.html. [10] Governmental Advisory Associates, Inc., METH2000 Database, Westport, CT, January 25, 2000.

[11] Douglas G. Hall, 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), //hydropower.inel. gov/resourceassessment/index.html.

[12] 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.

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