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Renewable Fuels Module

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. Renewable technologies cover the gamut of commercial market penetration, from hydroelectric power, which was one of the first electric generation technologies, to newer power systems using biomass, geothermal, LFG, solar, and wind energy.

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 descriptions in the "Commercial 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, the *AEO2010* 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 their projections are found in the residential, commercial, industrial, and petroleum marketing 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 that resource. A set of technology cost and performance values is provided directly to the EMM and are 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. Overnight capital costs are presented in Table 13.1 and the assumed capacity factors for new plants in Table 13.2.

Table 13.1. Overnight Capital Cost Characteristics for Renewable Energy Generating Technologies in Three Cases (2008$/kW)

Technology	Year	Reference	High Cost Renewable[1]	Low Cost Renewable
Geothermal[2]	2009	1,749	1,749	1,749
	2015	5,474	5,809	4,790
	2025	4,312	4,981	3,571
	2035	3,422	5,762	2,955
Hydroelectric[2]	2009	2,291	2,291	2,291
	2015	2,556	2,556	2,238
	2025	2,157	2,157	1,826
	2035	1,777	1,776	902
Photovoltaic[3]	2009	6,171	6,171	5,468
	2015	6,248	6,755	5,259
	2025	4,603	5,944	3,572
	2035	3,288	5,061	2,467
Solar Thermal Electric[3]	2009	5,132	5,132	4,414
	2015	4,814	5,618	4,047
	2025	3,617	4,943	2,804
	2035	2,555	4,209	1,918
Biomass[4]	2009	3,995	3,791	3,559
	2015	5,583	5,805	4,718
	2025	3,160	3,442	2,464
	2035	2,386	2,804	1,790
Offshore Wind	2009	3,937	3,841	3,505
	2015	4,118	4,204	3,490
	2025	3,374	3,699	2,641
	2035	2,662	3,150	1,997
Onshore Wind[4]	2009	1,966	1,966	1,759
	2015	2,546	2,582	2,170
	2025	2,225	2,272	1,753
	2035	1,884	1,935	1,414

[1]Overnight capital cost (that is, excluding interest charges), plus contingency, learning, and technological optimism factors, excluding regional multipliers. A contingency allowance is defined by the American Association of Cost Engineers as the specific provision for unforeseeable elements of costs within a defined project scope. This is particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur.

[2]Geothermal and Hydroelectric costs are specific for each site. The table entries represent the least cost unit available in the specified year in the Northwest Power Pool region. In the 2006 Renewables cases, costs vary as different sites continue to be developed.

[3]Biomass plants share significant components with similar coal-fired plants, these components continue to decline in cost in the Low Renewables case, although biomass-specific components (especially fuel handling components) do not see cost declines beyond 2010.

[4]Wind costs are region specific. The table represents costs in the Northwest Power Pool region.

Source: AEO2010 National Energy Modeling System runs AEO2010R.D110908A, HIRENCST10.D011410A, and LORENCST10.D011510A.

Table 13.2. Capacity Factors[1] for Renewable Energy Generating Technologies in Three Cases

	Calendar Year	AEO2010R.d111809A	HIRENCST10.D011410A	LORENCST10.D011510A
Geothermal[2]	2009	0.90	0.90	0.90
	2015	0.90	0.90	0.90
	2025	0.90	0.90	0.90
	2035	0.90	0.85	0.90
Hydrolectric[2]	2009	0.65	0.65	0.65
	2015	0.57	0.57	0.57
	2025	0.48	0.48	0.58
	2035	0.48	0.48	0.29
Photovoltaic	2009	0.21	0.21	0.21
	2015	0.21	0.21	0.21
	2025	0.21	0.21	0.21
	2035	0.21	0.21	0.21
Solar Thermal Electric	2009	0.31	0.31	0.31
	2015	0.31	0.31	0.31
	2025	0.31	0.31	0.31
	2035	0.31	0.31	0.31
Biomass	2009	0.83	0.83	0.83
	2015	0.83	0.83	0.83
	2025	0.83	0.83	0.83
	2035	0.83	0.83	0.83
Offshore Wind[3]	2009	0.43	0.43	0.43
	2015	0.43	0.43	0.43
	2025	0.45	0.43	0.45
	2035	0.45	0.43	0.45
Onshore Wind[3]	2009	0.44	0.44	0.44
	2015	0.46	0.44	0.40
	2025	0.46	0.44	0.40
	2035	0.40	0.44	0.40

[1]Capacity factor for units available to be built in specified year. Capacity factor represents maximum expected annual power output as a fraction of theoretical output if plant were operated at rated capacity for a full year.

[2]Hydroelectric capacity factors are specific for each site. The table entries represent the least-cost unit available in the specified year in the Northwest Power Pool region.

[3]Wind capacity factors are based on regional resource availability and generation characteristics. The table entries represent the highest quality resource available in the specified year.

Source: AEO2010 National Energy Modeling System runs AEO2010R.D110908A, HIRENCST10.D011410A, and LORENCST10.D011510A.

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 http://tonto.eia.doe.gov/reports/filterD.cfm?other=Documentation.

Aso assumed to affect all new capacity types are costs associated with construction commodities. Through the middle of this decade, 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 2009*, DOE/EIA-M069(2009) (Washington, DC, 2009).

Solar Electric Submodule

Background

The Solar Electric Submodule currently includes both concentrating solar power (thermal) and photovoltaics, including two solar technologies: 50 megawatt central receiver (power tower) solar thermal (ST) and 5 megawatt single axis tracking-flat plate photovoltaic (PV) technologies. PV is assumed available in all thirteen EMM regions, while ST is available only in the six Western regions with the arid atmospheric conditions that result in the most cost-effective capture of direct sunlight. Capital costs for both technologies are determined by EIA using multiple sources, including public reports of recent solar thermal capacity additions. Most other cost and performance characteristics for ST are obtained or derived from the August 6, 1993, California Energy Commission memorandum, *Technology Characterization for ER 94*; and, for PV, from the Electric Power Research Institute, *Technical Assessment Guide (TAG) 1993*. In addition, capacity factors are obtained from information provided by the National Renewable Energy Laboratory (NREL).

Assumptions

- 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. The current reference case solar thermal annual capacity factor for California, for example, is assumed to average 40 percent; California's current reference case PV capacity factor is assumed to average 24.6 percent.

- Because solar technologies are more expensive than other utility grid-connected technologies, early penetration will be driven by broader economic decisions such as the desire to become familiar with a new technology, environmental considerations, and the availability of limited Federal subsidies. Minimal early years' penetration is included by EIA as "floor" additions to new generating capacity (see "Supplemental and Floor Capacity Additions" below).

- 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 seven regions where ST 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 2030.

- 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.

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 14 mph, and wind speeds are categorized by annual average wind speed based on a classification system originally from the Pacific Northwest Laboratory. 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 derived by EIA from available data and from available literature.[3] 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 on *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 20, 50, 100 percent, and finally 200 percent, to represent the aggregation of these factors.

- Proportions of total wind resources in each category vary by EMM region. For all thirteen EMM regions combined, 1.3 percent of windy land is available with no cost increase, 5.4 percent is available with a 20 percent cost increase, 11.2 percent is available with a 50 percent cost increase, 27.3 percent is available with a 100 percent cost increase, and almost 54.8 percent of windy land is assumed to be available with a 200 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 are assumed to increase to a 46 percent in the best wind class resulting from taller towers, more reliable equipment, and advanced technologies. 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 48 percent for an average Class 6 site. As better wind resources are depleted, capacity factors are assumed to go down. By 2035, the typical wind plant build will have a somewhat lower capacity factor than those found in the best wind resource area.

- *AEO2010* does not allow plants constructed after 2012 to claim the Federal Production Tax Credit (PTC), a 2 cent per kilowatt-hour tax incentive that is set to expire on December 31, 2012. 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 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.

Geothermal-Electric Power Submodule

Background

The Geothermal-Electric Submodule (GES) estimates the generating capacity and output potential of 89 hydrothermal sites in the Western United States. This estimation is based on two studies: *New Geothermal Site Identification and Qualification*, prepared by GeothermEx, Inc for the California Public Utility Commission, and *Western Governors' Association Geothermal Task Force Report*, which was co-authored by several geothermal experts from the public and private sectors. These studies focus on geothermal resources with confirmed temperatures greater than 100 Celsius, which is generally considered the threshold for economically feasible conventional development. While EIA had previously distinguished between binary and dual flash technologies, this is no longer an essential component of cost estimates. Instead, these studies incorporate expected power plant cost and performance based on each confirmed resource temperature. This enables greater projection precision relative to a static choice between two technologies. All plants are assumed to operate at 90 percent capacity factor. Enhanced Geothermal Systems (EGS), such as hot dry rock, are not included as potential resources since this technology is still in development and is not expected to be in significant commercial use within the projection horizon. As part of EPACT 2005, the U.S. Geological Survey recently completed its comprehensive review of all domestic hydrothermal resources. While the final data show overall capacity estimates similar to the ones presented in the above-mentioned studies, there are undoubtedly distinctions in individual site characterizations and methods used for estimating capacity. Although the final aggregate data has been released, the assumptions and individual site estimates have not.

The two studies off of which EIA estimates are based maintain separate capital cost components for each site's development. The GeothermEx study divided individual site costs into four components: exploration, confirmation, development, and transmission. Site exploration is a small component of aggregate costs, oftentimes being zero. Confirmation and transmission costs may be significant, however the vast majority of capital costs are classified under site development which includes power plant construction. The WGA report, which was used to estimate geothermal potential outside of the GeothermEx database region, did not provide site specific, separate capital cost components. However, it did provide some sites with two levels of capital costs, meaning a portion of the resource could be developed at a lower cost than the remaining potential. Therefore, EIA maintained two categories of site specific capital development costs, with a cost premium placed on some sites beyond their most economic resource. Site specific operation and maintenance costs are also included in the submodule. As a result of revised supply estimations, the annual site build limit has been relaxed to 50mw of new capacity per site per year.

Assumptions

- Existing and identified planned capacity data are obtained directly by the EMM from Forms EIA-860A (utilities) and EIA-860B (nonutilities) and from supplemental additions (See Below).

- 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-cent production tax credit is available to this technology and is assumed chosen instead.

- Plants are not assumed to retire unless their retirement is reported to EIA. 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.

- Capital and operating costs vary by site and year; values shown in Table 8.3 in the EMM chapter are indicative of those used by EMM for geothermal build and dispatch decisions.

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 by the electricity sector is represented in the EMM, with capital and operating costs and capacity factors as shown in Table 8.2 in the EMM chapter, as well as fuel costs, being passed to the EMM where it competes with other sources. 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.

- The conversion technology represented, upon which the costs in Table 8.3 in the EMM chapter are based, is an advanced gasification-combined cycle plant that is similar to a coal-fired gasifier. Costs in the reference case were developed by EIA to be consistent with coal gasifier costs. Short-term cost adjustment factors are used.

- Biomass cofiring 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. Energy crop data are presented in yearly schedules from 2010 to 2035 in combination with the other material types for each region. 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 crop land, pasture land, or on Conservation Reserve Program lands. In AEO2009, agricultural residues and energy crops are combined into a single "agricultural sector." [7] The maximum amount of resources in each supply category is shown in Table 13.3.

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 35 percent of the total waste stream by 2005 and 50 percent by 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 the 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 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 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.

Table 13.3. 2020 Maximum U.S. Biomass Resources, by Coal Demand Region and Type
(Trillion Btu)

Coal Demand Region	States	Agricultural Sector	Forestry Residue	Urban Wood Waste/Mill Residue	Total[1]
1	CT, MA, ME, NH, RI, VT	165	158	15	339
2	NY, PA, NJ	277	167	59	503
3	WV, MD, DC, DE, VA, NC, SC	436	426	56	918
4	GA, FL	239	265	47	551
5	OH	348	37	16	402
6	IN, IL, MI, WI	1209	190	47	1,446
7	KY, TN	497	152	30	679
8	AL, MS	357	326	19	702
9	MN, IA, ND, SD, NE, MO, KS	2294	155	28	2,477
10	TX, LA, OK, AR	728	378	57	1,163
11	MT, WY, ID	197	100	25	322
12	CO, UT, NV	209	70	7	285
13	AZ, NM	168	45	7	220
14	AK, HI, WA, OR, CA	226	429	83	738

[1]May include rounding error.

Sources: Urban Wood Wastes: Antares Group Inc., *Biomass Residue Supply Curves for the U.S (updated),* prepared for the National Renewable Energy Laboratory, June 1999; Agricultural residues, energy crops, and forestry residues from the University of Tennessee Department of Agricultural Economics POLYSIS model, May 2008.

Legislation and Regulations

Energy Policy Act of 1992 (EPACT92) and 2005 (EPACT05)

The RFM includes the investment and energy production tax credits codified in the Energy Policy Act of 1992 (EPACT 92) as amended. The investment tax credit established by EPACT 92 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 utility, commercial and residential modules. The production tax credit, as established by EPACT 92, applied to wind and certain biomass facilities. As amended, it provides a 2.1 cent tax credit for every kilowatt-hour 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 and geothermal, and "closed loop" [12] biomass resources receive a 2.1 cent tax credit for the first 10 years of facility operations. All other renewable resources receive a 1 cent tax credit for the first 10 years of facility operations. EIA assumes that biiomass 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).

Alternative Renewable Cases

Renewable Technology Cases

Two cases examine the effect on energy supply using alternative assumptions for cost and performance of non-hyrdo, non-landfill gas renewable energy technologies. The High Renewable Cost case examines the effect if technology costs were to remain at current levels. The Low Renewable Cost case examines the effect if technology energy costs were reduced by 2035 to 25 percent below Reference case values with an initial reduction of 10%.

The High Renewable Cost case does not allow “learning-by-doing” effects to reduce the capital cost of biomass, geothermal, solar, or wind technologies or to improve wind capacity factor beyond 2010 levels. The construction of the first four units of biomass integrated gasification combined cycle units are still assumed to reduce the technological optimism factor associated with this technology. Although the cost of biomass fuels is assumed to remain the same in this case as in the Reference case, this case assumes that no energy crops will be available through 2035, consistent with the "frozen technology" assumptions for the other technologies. All other parameters remain the same as in the Reference case.

The Low Renewable Cost case assumes that the non-hydro, non-landfill gas renewable technologies are able to reduce their overall cost-of-energy produced in 2035 by 25 percent from the Reference case. Because the cost of supply of renewable resources is assumed to increase with increasing utilization (that is, the renewable resource supply curves are upwardly sloping), the cost reduction is achieved by targeting the reduction on the “marginal” unit of supply for each technology in 2035 for the Reference case (that is, the next resource available to be utilized in the Reference case in 2030). This has the effect of reducing costs for the entire supply (that is, shifting the supply curve downward by 25 percent). As a result of the overall reduction in costs, more supply may be utilized, and a unit from higher on the supply curve may result in being the marginal unit of supply. Thus the actual market-clearing cost-of-energy for a given renewable technology may not differ by much from the Reference case, although that resource contributes more energy supply than in the Reference case. These cost reductions are achieved gradually through "learning-by-doing”, and are only fully realized by 2030.

For wind, biomass, geothermal, and solar technologies, this cost reduction is achieved by a reduction in overnight capital costs sufficient to achieve the targeted reduction in cost-of-energy.   As a result, the supply of biomass fuel is increased at every price level. For geothermal, the capital cost of the lowest-cost site available in the year 2010 is reduced such that if it were available for construction in 2035, it would have a 25 percent lower cost-of-energy in the High Renewable case than the cost-of-energy it would have in 2035 were it available for construction in the Reference case. For solar technologies (both photovoltaic and solar thermal power), the resource is assumed to be unlimited and the reductions in cost-of-energy are achieved strictly through capital cost reduction. Biomass prices is assumed to be reduced 25 percent by 2035 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 portions of residential and commercial buildings, industrial processes, and refinery fuels modules. Details on these assumptions can be found in the corresponding sections of this report.

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 (described below), and nature of some of the limitations (also described below), 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 states were assigned to be within a single region, based on EIA expert judgment of factors such as predominant load locations and location of renewable resources eligible for that state's RPS program. 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 13.4.

Only targets with established enforcement provisions or established state funding mechanisms were included in the calculation; goals, provisional RPS requirements, or requirements lacking established funding were not included. The California and New York programs require state funding, and these programs are assumed to be complied with only to the extent that state funding allows. 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.

Table 13.4. Aggregate Regional RPS Requirements

Region[1]	2015	2025	2035
ECAR	3.0%	5.7%	5.7%
ERCOT	5.0%	5.0%	5.0%
MAAC	10.1%	15.4%	15.4%
MAIN	6.7%	15.3%	15.3%
MAPP	8.5%	11.1%	11.1%
NY	18.3%	18.3%	18.3%
NE	9.6%	13.8%	13.8%
FL	0.0%	0.0%	0.0%
STV	0.9%	1.9%	1.9%
SPP	1.9%	3.8%	3.8%
NWP	7.3%	13.7%	13.7%
RA	4.2%	6.9%	6.9%
CNV	18.7%	20.0%	20.0%

[1] See chapter on the electricity Market Module for a map of the electricity regions

Notes and Sources

[1] For a comprehensive description of each submodule, see Energy Information Administration, Office of Integrated Analysis and Forecasting, Model Documentation, Renewable Fuels Module of the National Energy Modeling System, DOE/EIA-M069(2005), (Washington, DC, March 2005).

[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] Wiser, Ryan and Mark Bollinger. Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006. U.S. Department of Energy, Office of Energy Efficiency and Reneweable Energy. May 2007.

[4] United States Department of Agriculture, U.S. Forest Service, "Forest Resources of the United States, 1992", General Technical Report RM-234, (Fort Collins CO, June 1994).

[5] Antares Group Inc., "Biomass Residue Supply Curves for the U.S (updated)", prepared for the National Renewable Energy Laboratory, June 1999.

[6] Walsh, M.E., et.al., Oak Ridge National Laboratory, "The Economic Impacts of Bioenergy Crop Production on U.S. Agriculture", (Oak Ridge, TN, May 2000), http://bioenergy.ornl.gov/papers/wagin/index.html.

[7] Graham, R.L., et.al., Oak Ridge National Laboratory, “The Oak Ridge Energy Crop County Level Database”, (Oak Ridge TN, December, 1996).

[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] Energy Information Administration, "Emissions of Greenhouse Gases in the United States 2003", DOE/EIA-0573(2003) (Washington, DC, December 2004).

[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).

[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