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Renewable Fuels Module

The NEMS Renewable Fuels Module (RFM) provides natural resources supply and technology input information for forecasts 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[112].

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. In some cases, they require technological innovation to become cost effective or have inherent characteristics, such as intermittency, which make their penetration into the electricity grid dependent upon new methods for integration within utility system plans or upon the availability of low-cost energy storage systems.

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.

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 *AEO2006* 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 39 in the chapter discussing the EMM. Overnight capital costs are presented in Table 72 and the assumed capacity factors for new plants in Table 73.

Table 72. Overnight Capital Cost Characteristics for Renewable Energy Generating Technologies in Three Cases (2004$/kW)

Technology	Year	Reference	High Renewables[1]	Low Renewables
Geothermal[2]	2010	1,675	1,675	1,709
	2020	2,392	2,392	2,572
	2030	2,298	2,308	2,572
Hydroelectric[2,]	2010	1,485	1,441	1,500
	2020	1,426	1,344	1,485
	2030	1,396	1,235	1,485
Landfill Gas	2010	1,579	1,547	1,595
	2020	1,531	1,436	1,595
	2030	1,499	1,436	1,595
Photovoltaic[3]	2010	4,105	4,020	4,276
	2020	3,569	3,317	4,198
	2030	2,923	2,628	4,004
Solar Thermal[3]	2010	2,527	2,527	2,808
	2020	2,309	2,198	2,782
	2030	2,067	1,792	2,757
Biomass[4]	2010	1,833	1,729	1,852
	2020	1,721	1,516	1,777
	2030	1,534	1,304	1,646
Wind	2010	1,194	1,182	1,206
	2020	1,194	1,122	1,206
	2030	1,194	1,086	1,206

[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]Costs decline slightly in the Low Renewable case for photovoltaic and solar thermal technologies as technological optimism is factored into initial costs (see pg. 72 in the chapter discussing the EMM). However, there is no learning-by-doing assumed once the optimism factor has been removed.

[4]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 2005.

Source: AEO2006 National Energy Modeling System runs AEO2006.D111905A, LOREN06.D120505A, and HIREN06.D120605A.

Table 73. Capacity Factors[1] for Renewable Energy Generating Technologies in Three Cases

Technology	Year	Reference	High Renewables	2006 Renewables
Geothermal[2]	2010	0.95	0.95	0.95
	2020	0.95	0.95	0.95
	2030	0.95	0.89	0.95
Hydrolectric[2]	2010	0.64	0.64	0.64
	2020	0.64	0.64	0.57
	2030	0.57	0.51	0.57
Landfill Gas	2010	0.90	0.90	0.90
	2020	0.90	0.90	0.90
	2030	0.90	0.90	0.90
Photovoltaic	2010	0.21	0.21	0.21
	2020	0.21	0.21	0.21
	2030	0.21	0.21	0.21
Solar Thermal	2010	0.31	0.31	0.31
	2020	0.31	0.31	0.31
	2030	0.31	0.31	0.31
Biomass	2010	0.83	0.83	0.83
	2020	0.83	0.83	0.83
	2030	0.83	0.83	0.83
Wind[3]	2010	0.44	0.46	0.37
	2020	0.45	0.46	0.37
	2030	0.41	0.43	0.37

[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]Geothermal and 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 least-cost resource available in the specified year in the Northwest Power Pool region.

Source: AEO2006 National Energy Modeling System runs: AEO2006.D111905A, LOREN06.D120505A, and HIREN06.D120605A.

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://www.eia.doe.gov/bookshelf/docs.html.

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 AEO2007, current and near-term plant installation costs for many generator types, including renewable plants, are reported to be significantly higher than the long-term estimates assumed in this Outlook. The factors contributing to these cost escalations include higher costs for raw materials, unfavorable currency exchange rates for imported equipment, and, in some high-growth markets, constrained project development infrastructure. These additional costs are not incorporated into the assumed costs shown, as they are short-term in nature, and not assumed to be reflective of the long-term fundamental technology costs. As indicated, short-term cost escalations resulting from high market growth are already incorporated into the model 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 2005*, DOE/EIA-M069(2005) (Washington, DC, 2005).

Solar Electric Submodule

Background

The Solar Electric Submodule (SOLES) 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 where direct normal solar insolation is sufficient. Capital costs for both technologies are determined by EIA using multiple sources, including 1997 technology characterizations by the Department of Energy's Office of Energy Efficiency and Renewable Energy and the Electric Power Research Institute (EPRI).[113] 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 or environmental considerations. 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 insufficient to make that technology commercially viable through 2030.

- NEMS represents the Energy Policy Act of 1992 (EPACT92) permanent 10-percent investment tax credit for solar electric power generation by tax-paying entities.

Wind-Electric Power Submodule

Background

Because of limits to windy land area, 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 from the Pacific Northwest Laboratory. The RFM tracks wind capacity (megawatts) by resource quality, distance to transmission, and other resource costs within a region and moves to the next best wind resource when one category is exhausted. For *AEO2007*, wind resource data on the amount and quality of wind per EMM region come from the National Renewable Energy Laboratory for 23 states[114] and a Pacific Northwest Laboratory study and a subsequent update for the remainder.[115] The technological performance, cost, and other wind data used in NEMS are derived by EIA from available data and in consultation with industry experts.[116] 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. The forecasts do not include off-grid or distributed electric generation.

- 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 contingous 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.

- EIA assumes that development of off-shore wind resources will be limited in the mid-term to a few niche projects, as a result of generally higher costs than on-shore locations and an abundance of viable and economically attractive on-shore sites. Available wind resources do not include off-shore locations.

- Wind resources are mapped by distance from existing transmission capacity among three distance categories, within (1) 0-5, (2) 5-10, and (3) 10-20 miles on either side of the transmission lines. Additional transmission costs are added to the resources further from the transmission lines. Transmission costs vary by region and distance from transmission lines, ranging from $4.10 per kW to $12.30 per kW (2002$).

- 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, (2) increasing cost of upgrading existing local and network distribution and transmission lines to accommodate growing quantities of intermittent 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, 1.2 percent of windy land is available with no cost increase, 1.8 percent is available with a 20 percent cost increase, 3.2 percent is available with a 50 percent cost increase, 3.2 percent is available with a 100 percent cost increase, and almost 91 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 national average of 44 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.

- *AEO2007* does not allow plants constructed after 2007 to claim the Federal Production Tax Credit (PTC), a 1.9 cent per kilowatt-hour tax incentive that is set to expire on December 31, 2007. Wind plants are assumed to depreciate capital expenses using the Modified Accelerated Cost Recovery Schedule with a 5-year tax life. The PTC and 30 percent ITC have recently been extended through December 31, 2008. This change occurred after completion of the AEO 2007 and is not reflected in these assumptions.

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 economic 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 forecasting 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 forecast horizon.

The two studies off of which EIA estimates are based maintain separate capital cost components for each site’s development, but do not focus on differing intrasite capital cost levels. 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. For *AEO2007*, as a result of revised supply estimations, the annual site build limit has been relaxed but still remains. Geothermal development is limited to 25 MW of generating capacity until 2010, when the 50 MW limit goes into effect for the remainder forecasting period.

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 forecast years based on the EPACT applies to all geothermal capital costs, except through 2007 when the 1.9 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 39 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 39 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 39 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 2030 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.[117] 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.[118] Agricultural residues are wheat straw, corn stover, and a number of other major agricultural crops.[119] Energy crop data are for hybrid poplar, willow, and switchgrass grown on crop land, pasture land, or on Conservation Reserve Program lands.[120] The maximum amount of resources in each supply category is shown in Table 74.

Table 74. Maximum U.S. Biomass Resources, by Coal Demand Region and Type
(Trillion Btu)

Coal Demand Region	States	Agricultural Residue	Energy Crops	Forestry Residue	Urban Wood Waste/Mill Residue	Total
1. NE	CT, MA, ME, NH, RI, VT	1	29	131	15	176
2..YP	NY, PA, NJ	29	73	89	59	250
3. SA	WV, MD, DC, DE, VA, NC, SC	63	116	408	56	643
4. GF	GA, FL	57	66	246	47	416
5. OH	OH	71	119	27	17	234
6. EN	IN, IL, MI, WI	409	307	404	47	1,167
7. KT	KY, TN	27	210	92	30	359
8. AM	AL, MS	18	211	149	19	397
9. CW	MN, IA, ND, SD, NE, MO, KS	900	1,004	523	28	2,455
10. WS	TX, LA, OK, AR	191	473	247	57	968
11. MT	MT, WY, ID	70	56	229	25	380
12. CU	CO, UT, NV	6	0	23	7	36
13. ZN	AZ, NM	6	0	23	7	36
14. PC	AK, HI, WA, OR, CA	104	0	195	83	382
Total U.S.		1,952	2,664	2,786	497	7,899

Sources: Urban Wood Wastes/Mill Residues: Antares Group Inc., *Biomass Residue Supply Curves for the U.S (updated),* prepared for the National Renewable Energy Laboratory, June 1999; Agricultural residues: James Easterly, "Biomass Suppy Curve Enhancement Regarding Agricultural Residues" prepared for EIA, September, 2004. All other biomass resources: Oak Ridge National Laboratory, personal communication with Marie Walsh, August 20, 1999.

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).[121]

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.*[122]
- 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.[123]

- 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).[124] 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 (non-impoundment) 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

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 most recently by the Energy Policy Act of 2005 (EPACT 05). 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 temporarily raised to 30 percent for some solar projects and extended to residential projects. This change is reflected in the commercial and residential modules, but is not reflected for utility-scale installations, where impacts are expected to be minimal. The production tax credit, as established by EPACT 92, applied to wind and certain biomass facilities. As amended, most recently by EPACT 05, it provides a 1.9 cent tax credit for every kilowatt-hour of electricity produced for the first 10 years of operation for a facility constructed by December 31, 2007. The value of the credit, originally 1.5 cents, is adjusted annually for inflation. With the EPACT 05 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. Poultry litter and geothermal resources receive a 1.9 cent tax credit for the first 10 years of facility operations. All other renewable resources receive a 0.9 cent tax credit for the first 10 years of facility operations. The investment and production tax credits are exclusive of one another, and may not both be claimed for the same facility.

Alternative 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 2006 Renewable Technology case examines the effect if technology costs were to remain at current levels. The High Renewable case examines the effect if technology energy costs were reduced by 2030 to 10 percent below Reference case values.

The 2006 Renewables 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 2006 levels. The construction of the first four units of biomass integrated gasification combined cycle units, utility-scale photovoltaic plants, or solar thermal plants are still assumed to reduce the technological optimism factor associated with those technologies. All other parameters remain the same as in the Reference case.

The High Renewables case assumes that the non-hydro, non-landfill gas renewable technologies are able to reduce their overall cost-of-energy produced in 2030 by 10 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 2030 for the Reference case (that is, the next resource available to be utilized in the Reference case in 2025). This has the effect of reducing costs for the entire supply (that is, shifting the supply curve downward by 10 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 in the High Renewable case. 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 biomass, geothermal, and solar technologies, this cost reduction is achieved by a reduction in overnight capital costs sufficient to achieve the 10 percent targeted reduction in cost-of-energy. As a result, the supply of biomass fuel is increased by 10 percent at every price level. For geothermal, the capital cost of the lowest-cost site available in the year 2005 (Roosevelt Hot Springs) is reduced such that if it were available for construction in 2030, it would have a 10 percent lower cost-of-energy in the High Renewable case than the cost-of-energy it would have in 2030 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.

Observation of wind energy markets indicates that improvements in performance (as measured by capacity factor) have, in recent years, dominated reductions in capital cost as a means of reducing cost-of-energy. Therefore, in the High Renewables case, the reduction in wind levelized cost comes from both modestly reduced capital cost and improved capacity factor. Other assumptions within NEMS are unchanged from the Reference case.

For the High Renewables 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

Because of limitations in the ability of NEMS to fully represent the various state-level policies generally known as Renewable Portfolio Standards (RPS), these are not represented in the AEO 2007 reference case. The AEO 2007 does represent an alternative case indicating potential market impacts of state RPS programs as aggregated at the electricity market region level, and without impact of the various alternative or discretionary compliance provisions contained within the state programs.

For this case, 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

Table 75. Aggregate Regional RPS Requirements

Region[1]	2015	2025	2030
ECAR	0%	0%	0%
ERCOT	5%	5%	5%
MAAC	9%	13%	13%
MAIN	0%	0%	0%
MAPP	7%	7%	7%
NY	22%	22%	22%
NE	10%	10%	10%
FL	0%	0%	0%
STV	0%	0%	0%
SPP	0%	0%	0%
NWP	3%	3%	3%
RA	3%	3%	3%
CNV[2]	12%	10%	10%

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

[2]Funding authorization for the California RPS program expires in 2011, but EIA estimates that the accumulated account can support increasing renewable generation through 2014 (assumes expiration of the Federal PTC in 2007). Target shown reflects EIA estimate of achievable target given limitations on program funding, not nominal target.

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 75.

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 from state-to-state, 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.

Supplemental and Floor Capacity Additions

For *AEO2007,* EIA has continued its tradition of supplemental and floor renewable capacity additions. All specific project listings in Table 76 have been independently verified by EIA, with the exception of landfill gas listings that were obtained through EPA. Capacity added under certain state renewable programs was included after these states have shown a history of successful compliance. Moreover, technology specific mandates and goals are easier to model than more open-ended requirements. EIA does not judge certain programs to be more effective, and provides a case with universal state compliance separate from the reference analysis. In total, 8.2 gigawatts of capacity are represented in these listings. For 2007 and beyond, the capacity additions are a preview of the limited data EIA currently has on new projects. Listings for these years should not be viewed as comprehensive.

In addition to the supplemental capacity additions in the electric power sector, for *AEO2007,* projections for new end-user-sited capacity include 2,345 megawatts of new photovoltaics capacity representing specifically identified expected new grid-connected end-user PV capacity or representative volumes known or assumed by EIA to be expected over the forecast period or emanating from state RPS and other requirements.

Table 76. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1]

Technology	Plant Identification	State	Net Summer Capability (Megawatts)	On-Line Years
Biomass				
	APS Biomass I	Arizona	2.9	2006
	Central Minnesota Ethanol Corp	Minnesota	0.95	2006
	Fibrominn Biomass Power Plant	Minnesota	55	2006
	Okeelanta Cogeneration	Florida	30	2006
	Schiller Biomass Conversion	New Hampshire	47.5	2006
	Sierra Pacific Burlington Facility	Washington	25	2006
	Ware Cogeneration	Massachusetts	4.1	2006
	Plant Carl Project	Georgia	20	2007
Landfill Gas (including mass-burn waste)	American Canyon SLF	California	0.4	2006
	Anderson Regional Landffill	South Carolina	10.8	2006
	Burlington County SLF	New Jersey	14.4	2006
	Cedar Hills Landfill	Washington	34	2006
	Central Disposal Landfill	Iowa	8	2006
	Chittenden County Landfill	Vermont	0.2	2006
	Clinton landfill Two	Illinois	6.4	2006
	Colonie LFG Facility	New York	4.8	2006
	Deer Track ParkLandfill	Wisconsin	6.4	2006
	Forth Worth Regional Landfill	Texas	3.2	2006
	Frey Farm Landfill	Pennsylvania	3.2	2006
	Glendale Road Landfill	Massachusetts	1.6	2006
	Hardin County LFG	Kentucky	2.4	2006
	Harrisburg Facility	Pennsylvania	21	2006
	Kiefer Landfill	California	6	2006
	Los Angeles Landfill	New Mexico	0.1	2006
	Los RealesLFG	Arizona	1.9	2006
	Modern Innovative Energy, LLC	New York	6.4	2006
	Orange County Landfill	California	4.2	2006
	Puente Hills Energy Recovery	California	9.9	2006
	Richmondf Couunty Landfill	South Carolina	5.3	2006
	Salt Lake Valley Landfill	Utah	6	2006
	Seminole Road Landfill Gas	Georgia	3.2	2006
	Seven Mile Creek LFG	Wisconsin	0.8	2006
	Timberline Trail Recycling Facility	Wisconsin	6.4	2006
	Warren County Landfill	New Jersey	7.6	2006
	Waste Disposal EngineeringSLF	Minnesota	0.4	2006
	Horry Landfill Gas Site	South Carolina	1.1	2007
	Lee County Landfill	South Carolina	1.9	2007
	Lee County Solid Waste Energy	Florida	16	2007

Table 76. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1] (cont)

Technology	Plant Identification	State	Net Summer Capability (Megawatts)	On-Line Years
Geothermal				
	Desert Peak	Nevada	36	2006
	East Mesa Expansion	California	9.5	2006
	Heber Geothermal	California	6	2006
	Stillwater Addition	Nevada	15	2007
	Galena I and II	Nevada	39	2006-2007
	Raft River Expansions	Idaho	22.1	2006-2007
	Salt Wells	Nevada	20.5	2006-2007
Coventional Hydroelectric				
	Atka Hydro	Alaska	0.3	2006
	Wanapum	Washington	235.2	2006
	Abiquiu Dam	New Mexico	3	2007
	Indian River Hydro I	Alaska	0.1	2007
	Lower St. Anthony Falls	Minnesota	9	2008
Central StationPhotovoltaics(PV)				
	Arizona RPS Solar PV	Arizona	2	2007
	Springerville Extension	Arizona	3	2008-2010
	Arizona Commercial Solar PV	Arizona	58.5	2008-2030
	California RPS Solar PV	California	38	2007-2017
	California Commercial Solar PV	California	76	2018-2030
	Nevada RPS Solar PV	Nevada	30	2007-2015
	Nevada Commercial Solar	Nevada	67.5	2016-2030
	Southern Great Plains Solar PV	Southern Plains	51	2007-2030
	Texas Mandate Solar	Texas	7.5	2007-2015
	Texas Commercial Solar PV	Texas	28.5	2016-2030
Solar Thermal				
	APS Solar Trough Plant	Arizona	1	2006
	Arizona RPS Solar Thermal	Arizona	1	2007
	Eldorado Solar Thermal	Nevada	70	2007
	Solargenix Solar Thermal	Nevada	64	2007
	California RPS Solar Thermal	California	13.5	2007-2017
	Nevada RPS Solar Thermal	Nevada	36.5	2007-2030
	AZ Commercial Solar Thermal	Arizona	23	2008-2030
	CA Commercial Solar Thermal	California	19.5	2018-2030
Wind				
	Allegheny Ridge Wind Farm	Pennsylvania	80	2006
	Aragonne Wind, LLC.	New Mexico	90	2006
	Atlantic City Wind Farm	New Jersey	7.5	2006
	AVECF Wind Phase IB	Alaska	0.3	2006
	Big Horn Wind Project	Washington	200	2006
	Bluegrass Ridge Project Phase I	Missouri	33.4	2006

Table 76. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1] (Cont.)

Technology	Plant Identification	State	Net Summer Capability (Megawatts)	On-Line Years
	Buena Vista	California	38	2006
	Buffalo Gap Wind Farm	Texas	120.6	2006
	Centennial Wind energy Project	Oklahoma	120	2006
	FPL Energy Burleigh County Wind	North Dakota	18	2006
	Hawaiian Renewable wind Farm	Hawaii	10.6	2006
	Horse Hollow Wind Center II and III	Texas	287.9	2006
	Huyll Municipal Light Plant	Massachusetts	1.8	2006
	Kaheawa Pastures	Hawaii	30	2006
	Kotzebue	Alaska	2.6	2006
	Leaning Juniper wind	Oregon	100.5	2006
	Lone Star Wind Farm	Texas	200	2006
	MA Maritime Academy	Massachusetts	1.3	2006
	Maple Ridge Wind Expansion	New York	94	2006
	Oliver Wind Energy	North Dakota	50.6	2006
	Portsmith Abbey School Turbine	Rhode Island	0.66	2006
	Shiloh I Wind Project	California	150	2006
	Solano Wiind	California	24	2006
	Spearville	Kansas	100	2006
	Spring Canyon	Colorado	60	2006
	Twin Buttes Wind Farm	Colorado	75	2006
	Twin Groves Wind Farm Phase I	Illinois	200	2006
	Victory Wind Energy Project	Iowa	99	2006
	Wild Horse Project	Washington	232	2006
	Wind Park Bear Creek	Pennsylvania	24	2006
	Wolverine Creek	Idaho	64.5	2006
	California RPS Wind	California	1954	2007
	Minnesota Mandate Wind	Minnesota	142	2007
	New England Wind	New England	442	2007
	Sandbluff Wind Project	Texas	90	2007
	Southeastern US Wind	Southeat Region	111	2007
	Forest Crerek Wind Farm	Texas	214.2	2006-2007
	Texas RPS Wind	Texas	1176	2008-2015
	Minnesota Small Wind	Minnesota	85	2006-2010
	Nevada RPS Wind	Nevada	114	2007-2008
	Consent Decree Wind	Ohio	23	2007-2009
	Tehachapi Windf Resource	California	15.9	2008-2009

1Includes reported information and EIA estimates for goals, mandates, renewable portfolio standards (RPS), and California Assembly Bill 1890 required renewables.

[2]Regional estimates developed by EIA.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on publicly available information about specific projects, state renewable portfolio standards, mandates, goals, and commercial and other plans.

Notes and Sources

[112] 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).

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[115] D.L. Elliott, L.L. Wendell, and G.L. Gower, An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States, Richland, WA: Pacific Northwest Laboratory, (PNL-7789), prepared for the U.S. Department of Energy under Contract DE-AC06-76RLO 1830, (August 1991); and Schwartz, N.N.; Elliot, O.L.; and Gower, G.L., Gridded State Maps of Wind Electric Potential Proceedings Wind Power 1992, (Seattle, WA, October 19-23, 1992).

[116] Primarily based on analysis of EIA Form 412 and Form 906 with additional discussion with U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, the National Renewable Energy Laboratory, and others.

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

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[124] 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).