Report #:DOE/EIA-0554(2006)
Release date: March 2006
Next release date: March 2007

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[108].

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 38 in the chapter discussing the EMM. Overnight capital costs are presented in Table 74 and the assumed capacity factors for new plants in Table 75.

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

Table 74. 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	1,916	1,850	2,013
	2020	1,594	2,115	2,008
	2030	2,639	2,271	2,665
Hydroelectric[2,]	2010	1,381	1,339	1,398
	2020	1,377	1,310	1,423
	2030	1,341	1,192	1,437
Landfill Gas	2010	1,524	1,490	1,544
	2020	1,486	1,389	1,544
	2030	1,447	1,389	1,544
Photovoltaic[3]	2010	3,931	3,848	4,138
	2020	3,436	3,196	4,046
	2030	2,832	2,523	3,882
Solar Thermal[3]	2010	2,605	2,550	2,742
	2020	2,325	2,161	2,735
	2030	2,030	1,760	2,707
Biomass[4]	2010	1,763	1,673	1,780
	2020	1,653	1,467	1,704
	2030	1,458	1,261	1,558
Wind	2010	1,153	1,150	1,167
	2020	1,150	1,115	1,167
	2030	1,149	1,080	1,167

[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.

permitting, equipment transport, and construction in good resource areas due to siting issues, inadequate infrastructure, or rough terrain.

Table 75. 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.

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 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).[109] 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 *AEO2006*, wind resource data on the amount and quality of wind per EMM region come from the National Renewable Energy Laboratory for 23 states[110] and a Pacific Northwest Laboratory study and a subsequent update for the remainder.[111] The technological performance, cost, and other wind data used in NEMS are derived by EIA from available data and in consultation with industry experts.[112] 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 continguous 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.

- 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.

- *AEO2006* 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.

Geothermal-Electric Power Submodule

Background

The Geothermal-Electric Submodule (GES), represents the generating capacity and output potential of 51 hydrothermal resource areas in the Western United States based on estimates provided in 1999 by DynCorp Corporation and subsequently modified by EIA.[113] Hot dry rock resources are not considered cost effective until after 2030 and are therefore not modeled in the GES. Both dual flash and binary cycle technologies are represented. The GES distributes the total capacity for each site within each EMM region among four increasing cost categories, with the lowest cost category assigned the base estimated costs, the next assigned higher (double) exploration costs, the third assigned a 33 percent increase in drilling and field costs, and the highest assigned both double exploration and 33 percent increased drilling and field costs. Drilling and field costs vary from site to site but are roughly half the total capital cost of new geothermal plants; exploration costs are a relatively minor component of capital costs. All quantity-cost groups in each region are assembled into increasing-cost suppy arrays. When a region needs new generating capacity, all remaining geothermal resources available in that region at or below an avoided cost level determined in the EMM are submitted (in three increasing cost subgroups) to compete with other technologies for selection as new generating supply. Geothermal capital costs decline with learning. For estimating costs for building new plants, new dual-flash capacity – the lower cost technology - is assigned an 80 percent capacity factor, whereas binary plants are assigned a 95 percent capacity factor; both are assigned an 87 percent capacity factor for actual generation.

To realistically reflect capacity availability through 2030 at each of the 51 geothermal sites, each site's potential is limited to about 100 megawatts for each of the four cost levels. Second, annual maximum capacity builds are established for each site, reflecting industry practice of expanding development gradually. For the reference case, each site is permitted a maximum development of 25 megawatts per year through 2015 and 50 megawatts per year thereafter.

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 38 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 38 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 38 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.[114] 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.[115] Agricultural residues are wheat straw, corn stover, and a number of other major agricultural crops.[116] Energy crop data are for hybrid poplar, willow, and switchgrass grown on crop land, pasture land, or on Conservation Reserve Program lands.[117] The maximum amount of resources in each supply category is shown in Table 76.

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).[118]

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.*[119]
- 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.[120]
- 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.

Table 76. 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.

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).[121] 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.

Supplemental and Floor Capacity Additions

Of the nearly 22 gigawatts of new renewable energy capacity projected to enter service in the electric power sector after 2004, 11.7 gigawatts of central station "supplemental additions'' were specifically added by EIA to account for identified new renewable energy projects and for limited amounts of new capacity determined to be highly likely to be built under state requirements such as renewable portfolio standards (RPS) and mandates or under voluntary goals, green power marketing programs, and other commercial ventures (summarized in Table 77 and detailed in Table 78).

Further, in addition to the supplemental capacity additions in the electric power sector, for *AE02006* projections for new end-user-sited capacity include 748 megawatts of new photovoltaics (PV) 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 77. Post-2004 Supplemental Capacity Additions (Megawatts Nameplate Capacity)

Rationale	Biomass	Conven-tional Hydro-electric	Geothermal	Landfill Gas	Solar Photovoltaic[2]	Solar Thermal	Wind	Total
RenewablePortfolio Standards[1]	41.15	25.99[2]	258.00	49.28	75.50	94.15	4728.15	5272.22
Mandates	55.00	0.00	0.00	50.00	7.50	0.00	4001.70	4114.20
Goals	0.27	12.10	0.00	5.80	0.00	0.00	301.40	319.57
Commercial[3]	75.00	251.20	12.70	39.80	281.50	70.50	1266.39	1997.09
Total	171.40	289.20	270.0	144.88	364.50	164.65	1029.60	11702.93

[1]Electric power sector grid-connected builds, including (a) specifically identified projects, (b) EIA estimates for goals, mandates, and renewable portfolio standards, and (c) other builds assumed by EIA to be built for reasons other than least-cost electricity supply.

[2]In addition to values shown in the table for the electric power sector, EIA assumes another 748 megawatts of grid-connected distributed PV will be installed 2005-2030 in the end-use sectors, including both identified projects and programs and additional capacity assumed by EIA to be installed for reasons in addition to least-cost supply. Excludes off-grid PV.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 78. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1]

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
Biomass					
	APS Biomass I	R	Arizona	3.0	2006
	Puente Hills Energy Recovery	R	Califonria	8.0	2005
	Buckeye Florida	C	Florida	25.0	2006
	Ware Cogeneration	R	Massachusetts	4.3	2006
	Worcester Energy	R	Maine	25.9	2005
	Fibrominn Biomass Power Plant	M	Minnesota	55.0	2007
	Schiller Biomass Conversion	C	New Hampshire	50.0	2006
	Blue Spruce Farm Anaerobic Digester	G	Vermont	0.3	2005
Landfill Gas (including mass-burn waste)	Los Reales LFG (Expansion)	R	Arizona	2.0	2006
	Lee County Solid Waste Energy	C	Florida	20.0	2007
	Owl Creek-Richmond Creek Road	C	Georgia	4.0	2005
	Dekalb County Landfill Gas	C	Georgia	3.2	2006
	New Paris Pike Landfill	C	Indiana	1.6	2005
	Pearl Hollow Landfill	C	Kentucky	2.4	2005
	Crapo Hill Landfill	R	Massachusetts	3.2	2005
	Glendale	R	Massachusettsi	1.2	2005
	Central Minn. Ethanol Corp.	G	Minnesota	1.0	2006
	Atlantic County Utilities Landfill	R	New Jersey	1.6	2005
	Brookside Dairy	R	Pennsylvania	0.1	2005
	IGENCO (Upton)	R	Pennsylvania	6.1	2005
	Lanchester	R	Pennsylvania	0.9	2005
	Pine Hurst Acres	R	Pennsylvania	0.1	2005
	Rolling Hills	R	Pennsylvania	2.0	2005
	Wanner's Pride	R	Pennsylvania	0.2	2005
	Harrisburg Facility	R	Pennsylvania	27.5	2006
	Lee County Landfill	C	South Carolina	7.6	2005, 2006
	Texas Mandate Landfill Gas	M	Texas	50.0	2006-2015
	Davis County	C	Utah	1.0	2005
	Coventry Landfill Gas	G	Vermont	4.8	2005
	Doubls S Dairy Digester	R	Wisconsin	0.4	2005
	Rodefield Landfill Gas	R	Wisconsin	4.0	2005
Geothermal					
	William R. Gould Geothermal	R	California	10.0	2005
	East Mesa Expansion	R	California	10.0	2006
	Raft River Phase I	C	Idaho	12.7	2006
	Desert Peak II, III	R	Nevada	26.0	2005, 2006
	Rye Patch	R	Nevada	12.0	2005

Table 78. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1] (cont)

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
	Galena I, Omi7	R	Nevada	20.0	2006
	Salt Wells I	R	Nevada	10.0	2006
	Nevada RPS Geothermal	R	Nevada	170.0	2006-2015
Coventional Hydroelectric					
	South Fork	C	Alaska	2.0	2005
	Atka Hydro	C	Alaska	0.3	2006
	Indian River Hydro 1	C	Alaska	0.1	2007
	Goat Rock	C	Alabama	5.4	2005
	El Dorado Project 184	R	California	22.0	2005
	Tungstar	R	California	1.0	2005
	Buford	C	Georgia	7.2	2005
	Puueo	G	Hawaii	3.1	2005
	Four Mile Hydropower Project	C	Michigan	0.2	2005
	Lower St. Anthony Falls	G	Minnesota	9.0	2008
	Abiquiu Dam	R	New Mexico	3.0	2007
	Wanapum	C	Washington	235.2	2006
	Swift Creek Power	C	Washington	0.8	2005
Central Station Photovoltaics(PV)	Saguaro	R	Arizona	1.0	2005
	Springerville Expansion	R	Arizona	4.0	2005-2010
	Arizona RPS Solar PV	R	Arizona	2.0	2007
	Arizona Commercial Solar PV	C	Arizona	58.5	2008-2030
	California RPS Solar PV	R	California	38.0	2007-2017
	California Commercial Solar PV	C	California	76.0	2018-2030
	Brocton Brightfields	R	Massachusetts	0.5	2005
	Nevada RPS Solar PV	R	Nevada	30.0	2007-2015
	Nevada Commercial Solar PV	C	Nevada	67.5	2016-2030
	Southern Great Plains Commercial Solar PV[3]	C	Southern Great Plains	51.0	2007-2030
	Texas Mandate Solar PV	M	Texas	7.5	2007-2015
	Texas Commercial Solar PV	C	Texas	28.5	2016-2030
Solar Thermal					
	Arizona Solar Trough	R	Arizona	1.0	2005
	Arizona RPS Solar Thermal	R	Arizona	1.0	2007
	Arizona Commercial Solar Thermal	C	Arizona	23.0	2008-2030
	California RPS Solar Thermal	R	California	13.5	2007-2017
	California Commercial Solar Thermal	C	California	19.5	2018-2030
	New Mexico Dish Stirling	R	New Mexico	0.2	2005
	Eldorado Solar Thermal	R	Nevada	70.0	2007
	Nevada RPS Solar Thermal	R	Nevada	36.5	2007-2030

Table 78. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1] (Cont.)

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
Wind	AVEC Wind Phase 1A, 1B	C	Alaska	0.9	2005, 2006
	Coram Energy LLC	R	California	9.0	2005
	Kumeyaay Wind	R	California	50.0	2005
	Shiloh Wind	R	California	150.0	2005
	Windridge, LLC	R	California	40.0	2005
	California RPS Wind	R	California	2930.0	2006, 2007
	Solano Wind	R	California	2.5	2006
	Tehachapi Wind Resource I, II	R	California	8.4	2006, 2007
	Spring Canyon	R	Colorado	60.0	2005
	Hawaii Remewable Dev. Wind Farm	G	Hawaii	10.6	2005
	Kaheawa Pastures	G	Hawaii	30.0	2006
	Century	C	Iowa	185.0	2005
	Intrepid expansion	C	Iowa	15.0	2005
	Fossil Gulch	C	Idaho	10.5	2005
	Wolverine Creek	C	Idaho	64.5	2005
	Adam and Eve Wind	G	Illinois	5.0	2005
	Cresent Ridge	G	Illinois	54.5	2005
	Illinois Electric Cooperative	G	Illinois	1.7	2005
	Sustainable Energy Foundation (FPC Services)	G	Illinois	1.7	2005
	Elk River Wind	C	Kansas	150.0	2005
	Sherman Co Comm Wind Part I	C	Kansas	3.0	2005
	IBEW Local 103 Adv Training Ctr	R	Massachusetts	0.1	2005
	Massachusetts Marittime Academy Bussard Bay	R	Massachusetts	0.7	2006
	Seven Turbines: Breezy, Bucks, Salty Dog, et al.	M	Minnesota	8.8	2005
	Fairmont	M	Minnesota	1.7	2005
	Palmer WindII	M	Minnesota	1.7	2005
	South Generation	M	Minnesota	1.7	2005
	St. Olaf College Wind	M	Minnesota	1.7	2005
	Trimont Area Wind Farm	M	Minnesota	100.5	2005
	U. Minn West Central Research	M	Minnesota	1.7	2005
	Minnesota Mandate Wind	M	Minnesota	184.0	2006, 2007
	Texas RPS 2006	M	Texas	155.0	2006
	Texas RPS 2007	M	Texas	155.0	2007
	Texas RPS 2008	M	Texas	154.0	2008
	Texas RPS 2009	M	Texas	154.0	2009
	Minnesota Small Wind	M	Minnesota	85.0	2006-2010
	Judith Gap	R	Montana	135.0	2005
	Velva North Dakota Wind	C	Noth Dakota	12.0	2005
	Wilton	C	North Dakota	49.5	2005

Table 78. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1] (Cont.)

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
	Ainsworth Wind	C	Nebraska	60.0	2005
	New England Wind[3]	C	New England	663.0	2006, 2007
	Atlantic City Wind Farm	R	New Jersey	7.5	2005
	(Elida) San Juan Mesa	R	New Mexico	120.0	2005
	Caprock Wind Farm	R	New Mexico	20.0	2005
	Nevada RPS Wind	R	Nevada	508.0	2006-2015
	Maple Ridge Wind Farm	G	New York	198.0	2005
	OhioConsent Decree Wind - Phase I, II	C	Ohio	23.0	2007-2009
	Blue Canyon Windpower	C	Oklahoma	151.0	2005
	Weatherford Wind Energy Ctr	C	Oklahoma	147.0	2005
	Klondike Wind Power	C	Oregon	75.0	2005
	Bear Creek	R	Pennsylvania	24.0	2005
	Southeastern US Wind[3]	C	Southeast	166.0	2006, 2007
	Buffalo Gap Wind Farm	M	Texas	120.6	2005
	Calahan Divide Wind Energy Center	M	Texas	114.0	2005
	Cottonwood Creek Wind	M	Texas	135.0	2005
	Horse Hollow Wind Energy Center	M	Texas	220.5	2005
	Suzlon	M	Texas	30.0	2005
	Sweetwater Wind 2 LLC	M	Texas	92.0	2005
	Texas Mandate Wind	M	Texas	2903.0	2006-2015
	Hopkins Ridge Wind	C	Washington	150.0	2005
	FE Warren AFB	C	Wyoming	1.3	2005
	J. Bar 9 Ranch Wind	C	Wyoming	0.0	2005
	Medicine Bow	C	Wyoming	2.8	2005

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

[2]"R" (RPS) represents state renewable portfolio standards; “M" (Mandate) identifies other forms of identified state legal requirements; “C" (Commercial) identifies other new capacity, including “green marketing” efforts and other voluntary programs and plans. Publicly available information does not always specify whether a project is mandated or a commercial build. Commercial building may or may not be used to satisify State requirements if eligible.

[3]Regional estimates developed by EIA.

Note: Publicly available information does not always specify whether a project is required, commercial, or other voluntary build; EIA characterizes unspecified projects as "commercial".

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

[108] 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).

[109] Electric Power Research Institute and U.S. Department of Energy, Office of Utility Technologies, Renewable Energy Technology Characterizations (EPRI TR-109496, December 1997) or www.eren.doe.gov/utilities/techchar.html.

[110] Draft Final Report to EIA on Incorporation of Existing Validated Wind Data into NEMS, November, 2003.

[111] 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).

[112] 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.

[113] Dyncorp Corporation, deliverable #DEL-99-548 (Contract #DE-AC01-95-ADF34277), Alexandria, Virginia, July, 1997).

[114] 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).

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

[116] 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.

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

[118] 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).

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

[120] Governmental Advisory Associates, Inc., METH2000 Database, Westport, CT, January 25, 2000.

[121] 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).