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 five submodules representing various renewable energy sources, biomass, geothermal, landfill gas, solar, and wind; a sixth renewable, conventional hydroelectric power, is represented in the Electricity Market Module (EMM).[119]

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 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 an original source of electricity generation, 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 low-cost energy storage.

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 *AEO2003* contains projections of nonelectric renewable energy uses for industrial and residential wood consumption, solar residential and commercial hot water heating, 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. The RFM submodules that interact with the EMM are the central station grid-connected biomass, geothermal, landfill gas, solar (thermal and photovoltaic), and wind submodules. Most provide specific data or estimates that characterize that resource in a useful manner. In addition, a set of technology cost and performance values is provided directly to the EMM. These values are central to the build and dispatch decisions of the EMM. The values are presented in Table 40. Overnight capital costs and other extended performance characteristics are presented in Table 73.

Conventional Hydroelectricity

The Hydroelectric Power Data File in the EMM represents reported plans for new conventional hydroelectric power capacity connected to the transmission grid and reported on Form EIA-860, *Annual Electric Generator Report*, and Form EIA-867, *Annual Nonutility Power Producer Report*. It does not estimate pumped storage hydroelectric capacity, which is considered a storage medium for coal and nuclear power and not a renewable energy use. However, the EMM allows new conventional hydroelectric capacity to be built in addition to reported plans. Converting Idaho National Engineering and Environmental Laboratory information on U.S. hydroelectric potential, the EMM contains regional conventional hydroelectric supply estimates at increasing capital costs. All the capacity is assumed available at a uniform capacity factor of 45 percent. Data maintained for hydropower include the available capacity, capacity factors, and costs (capital, and fixed and variable operating and maintenance). The fossil-fuel heat rate equivalents for hydropower are provided to the report writer for energy consumption calculation purposes only. Because of hydroelectric power's position in the merit order of generation, it is assumed that all available installed hydroelectric capacity will be used within the constraints of available water supply and general operating requirements (including environmental regulations).

Table 73. Cost and Performance Characteristics for Renewable Energy Generating Technologies: Two Cases

		Total Overnight Costs[1]		Best Available Capacity Factors	
Technology/Decision Year	Overnight Costs in 2001 (Reference) ($2000/kW)	Reference ($2000/kW)	High Renewable ($2000/kW)	Reference (%)	High Renewable (%)
Biomass	1,764				
2005		1,718	1,669	80	80
2010		1,635	1,573	80	80
2015		1,547	1,461	80	80
2020		1,464	1,352	80	80
2025		1,265	1,272	80	80
MSW - Landfill Gas[2]	1,461				
2005		1,451	1,451	90	90
2010		1,436	1,436	90	90
2015		1,420	1,420	90	90
2020		1,404	1,404	90	90
2025		1,388	1,388	90	90
Geothermal[3]	1,766				
2005		1,736	1,498	95	95
2010		1,624	1,236	95	95
2015		1,684	1,218	95	95
2020		1,614	1,240	95	95
2025		1,802	1,240	95	95
Wind	1,004				
2005		997	984	40	42
2010		994	951	41	44
2015		992	919	42	46
2020		990	886	42	47
2025		989	853	42	48
Solar Thermal	2,595				
2005		2,528	2,970	42	52
2010		2,413	3,056	42	63
2015		2,292	2,999	42	75
2020		2,170	2,942	42	77
2025		2,047	2,866	42	77
Photovoltaic	3,460				
2005		2,733	3,260	30	30
2010		2,462	1,686	30	30
2015		2,346	1,466	30	30
2020		2,270	1,246	30	30
2025		2,219	1,142	30	30

[1]Overnight capital cost (i.e.excluding interest charges), plus contingency factors and learning, excluding regional multipliers.

[2]Provided to show evolution of landfill gas costs through 2025; for landfill gas, assumptions in the high renewables case are unchanged from the reference case

[3]Because geothermal cost and performance characteristics are specific for each site, the table entries represent the least cost units available in the Northwest Power Pool region, where most of the proposed sites are located.

Source: Capital Costs: AEO2002 National Energy Modeling System runs: aeo2003.d110502c, hirenew03.d110602b; capacity factors: Energy Information Administration, Office of Integrated Analysis and Forecasting, as described in text in this report for each technology.

Capital Costs

The capital costs of renewable energy technologies are modified to represent two phenomena:

- Short-term cost adjustment factors, which increase technology capital costs as a result of rapid U.S. buildup in a single year, reflect limitations on the infrastructure (for example, manufacturing, resource assessment, construction expertise) to accommodate unexpected demand growth. These short-term factors are invoked when demand for new capacity in any year exceeds 50 percent of the prior year's total U.S. capacity. For every 1 percent increase in total U.S. capacity over the previous year greater than 50 percent, capital costs rise 0.5 percent for wind, 0.33 percent for biomass, and 1 percent for solar technologies.

- For geothermal and wind, higher costs are assumed to result from large cumulative increases in these resources' use, reflecting any or all of three general longer-term costs: (1) resource degradation, (2) transmission network upgrades, and (3) market factors. Presumably best land resources are used first. Increasing resource use necessitates resort to less efficient land - less accessible, less productive, more difficult to use (e.g, land roughness, slope, terrain variability, or productivity, wind turbulence or wind variability). Second, as capacity increases, especially for intermittent technologies like wind power, existing local and long-distance transmission networks require upgrading, increasing overall costs. Third, market pressures from competing land uses increase costs as cumulative capacity increases, including competition from agricultural or other production alternatives, residential or recreational use, aesthetics, or from broader environmental preferences. As a result, for *AEO2003*, each EMM region's wind resource estimates are parceled into five cost levels, 0, 20, 50, 100 and 200 percent respectively. For geothermal, four successive increments incur neither, either, or both of 33 percent increases in the drilling and field cost portions of capital costs and doubling of the relatively small exploration cost component. The size of the resource increments varies by technology and region.

For a description of NEMS algorithms lowering generating technologies' capital costs as more units enter service (learning), see "Technological Optimism and Learning" in the Electricity Market Module section 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 2003*, DOE/EIA-M069(2003) (Washington, DC, January 2003).

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 thin-film copper-indium-diselenide (CIS) photovoltaic (PV) technologies. PV is assumed available in all thirteen EMM regions, while ST is available only in the six primarily 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).[120] 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).

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 Cogeneration description in the "Commercial Demand Module" section of the report.

Assumptions

- Capacity factors for solar technologies are assumed to vary by time of day and season of 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 for such reasons 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; therefore, 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 2025.

- NEMS represents the Energy Policy Act of 1992 (EPACT) 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 wind speed is about 13 mph, and wind speeds are categorized into three wind classes according to annual average wind speed. The RFM tracks wind capacity (megawatts) within a region and moves to the next best wind class when one category is exhausted. Wind resource data on the amount and quality of wind per EMM region come from a Pacific Northwest Laboratory study and a subsequent update.[121] The technological performance, cost, and other wind data used in NEMS are derived by EIA from consultation with industry experts.[122] 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 is constrained 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.

- Availability of wind power (among three wind classes) is based on the Pacific Northwest Laboratory Environmental and Moderate Land-Use Exclusions Scenario, in which some of the windy land area is not available for siting of wind turbines. The percent of total windy land unavailable under this scenario consists of all environmentally protected lands (such as parks and wilderness areas), all urban lands, all wetlands, 50 percent of forest lands, 30 percent of agricultural lands, and 10 percent of range and barren lands.

- Wind resources are mapped by distance from existing transmission capacity among three distance categories, accepting wind resources within (1) 0-5, (2) 5-10, and (3) 10-20 miles on either side of the transmission lines. Transmission cost factors are added to the resources further from the transmission lines.

- Capital costs for wind technologies are also 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, the increasing costs of alternative land uses, including for 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 in each category vary by EMM region.

- 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 "fuel savers" 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 and fuel costs for existing (non-wind) capacity. When competing in the new capacity market, wind is assigned a capacity credit that declines with increasing market penetration.

- 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 windy land area and is factored into requests for generating capacity by the EMM.

- Capacity factors are assumed to increase, as a function of market penetration, to a national average of about 42 percent in the best wind class resulting from taller towers, more reliable equipment, and advanced control technologies. However, as better wind resources are depleted, capacity factors are assumed to go down.

- *AEO2003* includes the 1.5 (adjusted for inflation to 1.8) cent per kilowatthour Federal production tax credit (PTC) received for the first 10 years of a new wind unit's production; the PTC is applied to all taxpayer-owned wind units entering service from 1993 through 2003. The PTC is represented in NEMS as a 2.8 cent per kilowatthour reduction in required electricity plant revenue in order to more accurately represent its after-tax market value. Although a similar Federal incentive exists for publicly-owned (non tax paying) units, all wind units are assumed owned by taxpaying entities in the RFM.

For *AEO2003*, capacity factors for each wind class are no longer determined outside the model and input, but rather calculated as a function of overall wind market growth. This growth is assumed to be limited to about a 45 percent capacity factor for an average Class 6 site. However, the level of wind growth achieved in the Reference Case results in a final Class 6 capacity factor of 42 percent.

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 updated estimates provided in 1999 by DynCorp Corporation and subsequently modified by EIA.[123] Hot dry rock resources are not considered cost effective until after 2025 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 (along with plant costs) of new geothermal plants; exploration costs are a relatively minor additional component of capital costs. All quantity-cost groups in each region are assembled into increasing-cost supplies. 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 as for other technologies. 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.

For *AEO2002* and retained in *AEO2003*, the GES was modified and estimates of available supply were reduced. First, to more realistically reflect each of the 51 sites' capacity availability through 2020, the 40-year estimates included for *AEO2001* were reduced, usually to about 100 megawatts for each of four cost levels for each site. Second, annual maximum capacity builds were established for each site, reflecting industry practice of expanding development gradually. For the reference case, each site was permitted a maximum development of 25 megawatts per year through 2015 and 50 megawatts per year thereafter; for the high renewables case, the 50 megawatt annual limit applies to all years.

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.

- Plants are not assumed to retire unless their retirement is reported to EIA. Geysers units are not assumed to retire but instead have the 35 percent capacity factors reported to EIA reflecting declining performance in recent years.

- Capital and operating costs vary by site and year; values shown in Table 40 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 40, 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, these same supply schedules.

Assumptions

- Existing and planned capacity data are obtained from Forms EIA-860A and EIA-860B.

- The conversion technology represented, upon which the costs in Table 40 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. The first three are combined into a single supply schedule for each region which does not change for the full forecast period. Energy crops data are presented in yearly schedules from 2010 to 2020 in combination with the other material types for each region. The forestry materials component is made up of logging residues, rough rotten salvable dead wood and excess small pole trees.[124] 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.[125] Agricultural residues are wheat straw and corn stover only, which make up the great majority of crop residues.[126] Energy crops data are for hybrid poplar, willow and switchgrass grown on crop land, pasture land, or on Conservation Reserve lands.[127] The maximum amount of resources in each supply category is shown in Table 74.

Table 74. U.S. Biomass Resources, by Region and Type, 2025
(Trillion Btu)

	Forest Resources	Urban Wood Waste/ Mill Residue	Energy Crops	Agricultural Residue	Total
1. ECAR	363	156	183	407	1,110
2. ERCOT	29	45	78	57	210
3. MAAC	44	50	19	28	142
4. MAIN	125	36	112	439	712
5. MAPP	191	39	398	946	1,573
6. NPCC/NY	40	63	59	3	165
7. NPCC/NE	81	50	38	0	170
8. SERC/FL	32	42	4	0	79
9. SERC	342	307	217	61	927
10. SPP	225	138	387	264	1,014
11. NWP	414	180	0	53	647
12. W/RA	105	30	6	54	195
13. W/CNV	43	94	0	23	161
Total US	**2,036**	**1,231**	**1,501**	**2,335**	**7,103**

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; 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).[128]

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 2000*[129].

- 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[130].

- 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.

High Renewables Case

The High Renewables case examines the effect on energy supply of using cost and performance assumptions for nonhydro, non-landfill gas renewable energy technologies approximating published goals of the relevant program offices of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (DOE/EE). For electric power sector technologies, the High Renewables assumptions are designed to correspond to year 2020 cost and performance goals in the *Renewable Energy Technology Characterizations* document jointly published by the DOE/EE and the Electric Power Research Institute (EPRI). [131] These assumptions, summarized in Table 70, include:

- Biomass: For biomass in the high renewables case, capital costs are modified from reference case values such that they are similar to those in the EE/EPRI *Technology Characterization* costs for biomass gasification by 2025. In addition, biomass supplies are increased 10 percent across all price steps for the four types of biomass. Fixed operations and maintenance costs are reduced about 14 percent to be consistent with *Technology Characterization* costs. Biomass capacity factors are unchanged from the reference case.

- Geothermal: For geothermal in the high renewables case, EIA assumes that (1) capital costs for all 51 sites in 2000 match higher EIA rather than EE *Technology Characterization* estimates for this “base” year, (2) EIA assumptions for capital costs decline at a rate sufficient to match *Technology Characterization* estimates by 2010, meaning that high renewables case assumptions remain higher than DOE/EE assumed costs through 2009 and (3) the lowest cost geothermal site available in 2000 (Roosevelt Hot Springs), would, if available for selection in 2020 (decision year), meet the 2020 *Technology Characterization* capital cost goal in that year, about 36 percent below its current $1800 per kilowatt ($99) cost. Finally, because each of the 51 sites is separately priced, EIA applies the rates (rather than amounts) of capital cost decline necessary for Roosevelt Hot Springs to meet these requirements to all other 50 sites. Overall, each site’s capital cost declines by 3 percentage points per decision year from 2000-2010, and by 0.6 percentage point per year from 2011-2020, using the capital cost weights:

Decision Year	Weight
2000	1.00
2005	0.85
2010	0.70
2015	0.67
2020	0.64

Least cost geothermal sites in any case result from the interaction of (a) baseline cost estimates for each site, (b) cost adjustment factors, and (c) increased costs as least-cost units are taken and higher cost sites are chosen. Therefore, in the high renewables case results, actual 2020 marginal capital costs by 2020 will not necessarily be lower than in the reference case but will instead show greater quantities of geothermal available and chosen before again attaining the higher marginal costs.

In the high renewables case, geothermal capacity factors and fixed operations and maintenance costs (O&M) are unchanged from the reference case.

- Photovoltaics (Central Station): For photovoltaics, EIA assumes reduced capital and operations and maintenance costs, corresponding to utility scale flat plate "Thin Film" technology in the EE/EPRI *Technology Characterizations*. Performance is assumed unchanged from the reference case.

- Solar Thermal: For solar thermal in the high renewables case, EIA assumes increased capital costs compared to the reference case, with significantly improved performance (as measured by capacity factor); in addition, operations and maintenance costs are reduced. This corresponds with the Central Receiver (Solar Power Tower) technology in the EE/EPRI *Technology Characterization*, which incorporates, at additional cost, increasing levels of thermal energy storage in the forecast years. To reflect the improved dispatch characteristics of integrated thermal storage, the capacity credit for solar thermal technologies in this case is set equal to the regional capacity factor during the peak load period.

- Wind: EIA assumes reduced capital and operations and maintenance costs, with increased performance (as measured by capacity factor and energy capture per swept rotor area) in all wind classes. The maximum allowable capacity factor is set to 49 percent, and the growth rate parameters are increased to allow the model to achieve capacity factor goals specified in the EE/EPRI *Technology Characterizations*. Because the *Technology Characterizations*, which were published in 1997, substantially underestimate the observed 2002 capital cost range for wind turbines, the capital cost decline used in this case reflects the rate of decline through 2025 implied by the *Technology Characterizations,* but using the Reference Case assumption for current capital cost.

Because costs are assumed to decline (or increase, in the case of Solar Thermal) based on the exogenous cost trajectory of the *Technology Characterizations*, the normal learning function of the EMM does not apply to these capacity types. Thus cost targets are achieved regardless of actual market penetration.

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.

Legislation

Energy Policy Act of 1992 (EPACT)

The RFM includes the investment tax and energy production credits established in the EPACT for the appropriate energy types. EPACT provides a renewable electricity production tax credit (PTC) of 1.5 cents per kilowatt-hour for electricity produced by wind, applied to plants that become operational between January 1, 1994, and June 30, 1999; *AEO2003* includes extension of the PTC (adjusted for inflation to 1.8 cents) through December 31, 2003, as provided in section 507 of the Tax Relief Extension Act of 1999 as well as by the Job Creation and Worker Assistance Act of 2002. The credit extends for 10 years after the date of initial operation. EPACT also includes provisions that allow an investment tax credit of 10 percent for solar and geothermal technologies that generate electric power. This credit is represented as a 10-percent reduction in the capital costs in the RFM.

Supplemental and Floor Capacity Additions

In addition to capacity projected through the use of the EMM and RFM, including 6.7 gigawatts additional renewables in the electric power sector, 4.3 gigawatts added in the large end-use heat and power sector, and another 900 megawatts in the small end-use sector, *AEO2003* also includes 6,680 megawatts additional renewables generating capacity identified by EIA as entering service through 2025 (Supplemental Additions). Summarized in Table 75 and detailed in Table 76, some of the capacity represents mandated new capacity required by state laws, EIA estimates for expected new capacity under state-enacted renewable portfolio standards (RPS), estimates of winning bids in California's renewables funding program (Assembly Bill 1890), expected new capacity under known voluntary programs, such as "green marketing" efforts, and other publicly stated plans. The additions do not include off-grid or distributed photovoltaics or hydroelectric power.

In addition to the Supplemental Additions, projections also include 75.5 megawatts central station thermal-electric and 332.5 megawatts central station photovoltaic (PV) generating capacity ("Floors") assumed by EIA to be installed for reasons in addition to least-cost electricity supply 2001-2025.

Table 75. Post-2001 Supplemental Capacity Additions (Megawatts, Net Summer Capability)

Rationale	Biomass	Conven-tional Hydro-electric	Geothermal	Landfill Gas	Solar Thermal	Solar Photovoltaic	Wind	Total
Mandates[1]	156.8	0.0	0.0	9.1	0.0	0.0	928.6	1094.5
RenewablePortfolio Standards	198.6	0.0	332.5	545.5	89.0	3.0	2319.5	3488.1
California AB1890[2]	28.5	0.0	47.4	93.7	0.0	0.0	453.9	623.5
Other Reported Plans[3]	28.5	560.0	177.7	168.7	0.0	2.4	537.4	1474.7
Total	412.4	560.0	557.6	816.9	89.0	5.4	4239.3	6679.7

[1]includes mandates and goals.

[2]Partially supported by funding under California Assembly Bill 1890.

[3]Other non mandated plans, including "green marketing" efforts and other activities known to EIA.

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

Table 76. Planned 2002+ U.S. Central Station Generating Capacity Using Renewable Resources[1]

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
Biomass (Including mass-burn waste)	Env. Forest Solutions	Commercial	Arizona	2.9	2002
	Arizona (various)	RPS	Arizona	17.1	2003-2007
	Mesquite Lake	AB1890	California	28.5	2002
	Jacobs Energy	Commercial	Illinois	5.3	2002
	Ware Cogeneration	Commercial	Massachusetts	7.8	2003
	Massachusetts (various)	RPS	Massachusetts	70.3	2003, 2006 2012-2020
	St. Paul Cogen (A)	Mandate	Minnesota	23.8	2002
	St. Paul Cogen (B)	Commercial	Minnesota	7.6	2002
	Fibromin Poultry Litter	Mandate	Minnesota	47.5	2004
	NSP Biomass II	Mandate	Minnesota	23.8	2004
	Beck LLC (Whole Tree)	Mandate	Minnesota	47.5	2005
	New Jersey (various)	RPS	New Jersey	63.7	2005-2016
	Nevada (various)	RPS	Nevada	47.5	2005-2016
	Gorge Energy	Commercial	Washington	5.0	2002
	Five Site Waste-Energy	Mandate	Wisconsin	14.3	2003
Landfill Gas	Arizona (various)	RPS	Arizona	17.1	2003-2007
	California (various)	Commercial	California	22.6	2002
	California (various)	AB1890	California	93.7	2002-2005
	SW Alachua	Commercial	Florida	2.4	2002
	Georgia (various)	Commercial	Georgia	9.1	2002
	Illinois (various)	Commercial	Illinois	16.9	2002
	Com-Ed BioEnergy	Goal	Illinois	5.2	2002
	South Side	Commercial	Indiana	0.3	2002
	Jefferson Davis	Commercial	Louisiana	4.0	2002
	Plainville	Commercial	Massachusetts	5.3	2002
	Massachusetts (various)	RPS	Massachusetts	251.8	2002-2020
	Eastern (White Marsh)	Commercial	Maryland	4.0	2002
	Southeast Berrien County	Commercial	Michigan	4.6	2002
	Spruce Ridge	Commercial	Minnesota	3.0	2003
	Douglas County Landfill	Commercial	Nebraska	3.0	2002
	New Jersey (various)	RPS	New Jersey	136.8	2005-2016
	Broome County Nanticoke	Commercial	New York	0.7	2002
	Blackburn Cogen.	Commercial	North Carolina	1.0	2002
	Glenwillow	Commercial	Ohio	2.7	2002
	Wyandotte	Commercial	Ohio	2.0	2003
	Finley Buttes	Commercial	Oregon	2.0	2003
	Three Mile Canyon Farms	Mandate	Oregon	3.9	2004
	PPL Northern Tier	Commercial	Pennsylvania	0.8	2002
	Pioneer Crossing	Commercial	Pennsylvania	0.3	2003
	Enoree, Phase II	Commercial	South Carolina	1.7	2002

Table 76. Planned 2002+ U.S. Central Station Generating Capacity Using Renewable Resources (Continued)

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
	Reliant Ennergy	Commercial	Texas	25.5	2002
	Texas (various)	Commercial	Texas	34.9	2002, 2003
	Texas (various)	RPS	Texas	109.4	2003-2020
	Virginia (various)	Commercial	Virginia	16.5	2002
	Ridgeview Recycling	Commercial	Wisconsin	2.4	2002
	Brown County West	Commercial	Wisconsin	3.0	2003
	Wisconsin (various)	RPS	Wisconsin	30.4	2008-2011
Geothermal	Four Mile Hill	AB1890	California	47.4	2004
	Salton Sea Unit 6	Commercial	California	175.8	2005
	Animas	Commercial	New Mexico	1.0	2003
	Empire	Commercial	Nevada	1.0	2003
	Nevada (various)	RPS	Nevada	332.5	2003-2015
Conventional Hydroelectric	Low Impact Hydro Unit	Commercial	Arizona	0.8	2003
	Smithland, Phase I	Commercial	Kentucky	16.0	2004
	Arizona Falls	Commercial	Nebraska	0.7	2002
	Swift Creek Power	Commercial	Wyoming	0.7	2003
Central Station Photovoltaics	Tucson Electric	Commercial	Arizona	1.5	2002
	Salt River Project, I	Commercial	Arizona	0.03	2002
	Salt River Project, II	Commercial	Arizona	0.1	2003
	Arizona (various)	RPS	Arizona	3.0	2007
	LA Dept. Water and Power	Commercial	California	0.8	2003-2005
Solar Thermal	Welton-Mohawk	RPS	Arizona	35.0	2005
	Arizona (various)	RPS	Arizona	4.0	2004-2007
	Nevada (various)	RPS	Nevada	50.0	2005
Wind	Alta Mesa IV	AB1890	California	25.2	2002
	Tehachapi	Commercial	California	0.3	2002
	Cal Wind	AB1890	California	8.7	2002
	McIntosh	AB1890	California	280.0	2003
	McIntosh	AB1890	California	140.0	2005
	Gobblers Knob	Commercial	Colorado	162.0	2003
	Maui Electric	Commercial	Hawaii	20.3	2002
	Clarion-Goldfield School	Commercial	Iowa	0.1	2002
	Eldora-New Prov. School	Commercial	Iowa	0.8	2002
	Hancock County Wind	Mandate	Iowa	91.0	2002
	Turbodynamx (IIT)	Goal	Illinois	0.01	2002
	Crescent Ridge	Goal	Illinois	51.0	2003
	Equinox Mountain	Commercial	Maine	4.6	2002
	Equinox	RPS	Massachusetts	25.0	2003
	Massachusetts (various)	RPS	Massachusetts	765.0	2006-2020
	NSP Mandate Phase IV	Mandate	Minnesota	80.0	2002

Table 76. Planned 2002+ U.S. Central Station Generating Capacity Using Renewable Resources (Continued)

Technology	Plant Name	Program[2]	State	Net Summer Capacity (Megawatts)	On-Line Years
	Dodge County (5 sites)	Mandate	Minnesota	9.5	2002
	Worthington Municipal	Commercial	Minnesota	4.5	2002
	Pipestone County (9 sites)	Mandate	Minnesota	17.0	2002
	JJN Windfarm LLC	Mandate	Minnesota	1.8	2002
	Chanarambie Power	Mandate	Minnesota	85.5	2003
	Murray County (8 sites)	Mandate	Minnesota	12.0	2003
	Navitas Project (Murray)	Mandate	Minnesota	51.0	2003
	Montana Wind Harness	Mandate	Montana	150.0	2003
	Minot	Commercial	North Dakota	2.6	2002
	Petersburg (Valley City)	Commercial	North Dakota	0.9	2002
	Dickey County	Commercial	North Dakota	20.0	2003
	Kimball County Mun.	Commercial	Nebraska	10.5	2002
	New Jersey (various)	RPS	New Jersey	140.0	2001-2016
	Nevada (various)	RPS	Nevada	348.0	2005-2013
	Atlantic Renewable	Mandate	New York	18.0	2002
	Zilhka, Erie County	Mandate	New York	50.0	2003
	Atlantic Ren. (Lewis Cty.)	Mandate	New York	100.0	2003
	Global Wind Harvest I	Mandate	New York	75.0	2003
	Global Wind Harvest II	Mandate	New York	40.5	2003
	York Wind (Chautauqua)	Mandate	New York	51.0	2003
	Condon Part II	Commercial	Oregon	25.2	2002
	Stateline Expansion Part I	Commercial	Oregon	39.6	2002
	Nine Mile Canyon	Commercial	Oregon	48.0	2002
	Stateline Expansion (FPL)	Commercial	Oregon	40.0	2003
	Combine Hills (Umatilla)	Commercial	Oregon	104.0	2003
	Energy Trust 2003	Mandate	Oregon	25.0	2003
	Humbolt Industries	Commercial	Pennsylvania	0.1	2002
	Chamberlain Unit	Commercial	South Dakota	2.6	2002
	Indian Mesa	RPS	Texas	82.5	2002
	Noelke Hills Wind Ranch	RPS	Texas	240.0	2003
	Cielo Austin Energy	Commercial	Texas	25.0	2003
	Texas (various)	RPS	Texas	569.0	2002-2009
	Stateline Expansion Part II	Commercial	Washington	19.8	2002
	Nine Canyon Wind	Commercial	Washington	26.8	2002
	Wisconsin (various)	RPS	Wisconsin	32.0	2008-2011
	Mountaineer Backbone	RPS*	West Virginia	66.0	2002
	PoconoWaymart	RPS*	West Virginia	52.0	2003

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

[2]RPS" represents state renewable portfolio standards; "AB 1890" represents California Assembly Bill 1890; "Mandate" identifies other forms of identified state legal requirements; "Commercial" identifies other new capacity, not know by EIA to be required, 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.

*Located in West Virginia to meet Pennsylvania RPS.

Notes and Sources

[119] 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(2002), (Washington, DC, January 2002).

[120] 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.

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[122] Energy Information Administration analysts discussed input values with the Electric Power Research Institute, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, the National Renewable Energy Laboratory, and others.

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

[124] 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).

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

[126] 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.

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

[128] 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).

[129] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000) (Washington, DC, November 2001).

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

[131] Department of Energy assumptions are obtained or derived from Electric Power Research Institute and U.S. Department of Energy, Office of Utility Technologies, *Renewable Energy Technology Characterizations* (EPRI TR-109496, Dec. 1997) or www.eren.doe.gov/utilities/techchar.html.