Renewable Fuels Module of the National Energy Modeling System: Model Documentation 2016

May 2017

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other federal agencies.

Update Information

This edition of the Renewable Fuels Module—Model Documentation 2016 reflects changes made to the renewable fuels module over the past year for the Annual Energy Outlook 2016. These changes include:

- Updating capital costs for onshore wind and solar photovoltaic to reflect the declining technology costs;
- Updating renewable portfolio standards (RPS) to reflect the upward revisions of the mandate in several states, including Vermont, Hawaii and California. Kansas has ended its RPS requirement; and
- Extending federal tax credits—production tax credit (PTC) and investment tax credit (ITC) to reflect the extension of those tax credits by Congress.

Contents

Tables

Figures

1. Introduction

Purpose of this report

This report documents the objectives, analytical approach, and design of the National Energy Modeling System (NEMS) Renewable Fuels Module (RFM) as it relates to the production of the *Annual Energy Outlook 2016* (AEO2016) forecasts. The report catalogues and describes modeling assumptions, computational methodologies, data inputs, and parameter estimation techniques. A number of offline analyses used in lieu of RFM modeling components are also described.

This documentation report serves three purposes. First, it is a reference document for model analysts, model users, and the public interested in the construction and application of the RFM. Second, it meets the legal requirement of the U.S. Energy Information Administration (EIA) to provide adequate documentation in support of its models (Public Law 93-275, Federal Energy Administration Act of 1974, Section 57(b) (1)). Finally, such documentation facilitates continuity in EIA model development by providing information sufficient to perform model enhancements and data updates as part of EIA's ongoing mission to provide analytical and forecasting information systems.

Renewable Fuels Module summary

The RFM consists of six submodules that represent major renewable electricity resources: biomass, landfill gas (LFG), solar (thermal and photovoltaic), wind, geothermal, and conventional hydroelectricity energy.

The purpose of the RFM is to define the technology, cost, performance, and renewable resource supply for renewable electricity technologies in the NEMS. The RFM estimations are provided to the Electricity Market Module (EMM) for use in projecting grid-connected central station electricity capacity planning and dispatch decisions. Projected characteristics include available generating capacity, location, unit size, capital cost, fixed operating cost, variable operating cost, capacity factor, heat rate, construction lead time, and fuel price. Because of the extensive interaction between the RFM and EMM, these two modules must be run together.

Renewable electricity technology cost and performance characteristics that are common to all electricity generating technologies are input directly to the EMM via the input file ECPDAT. Unique characteristics such as renewable resource values for regional, seasonal, and hourly time segments of intermittent renewables are supplied in specific files and subroutines to specific renewable electricity technologies.

Other renewables modeled elsewhere in NEMS include biomass in the industrial sector, biofuels in the Liquid Fuels Market Module (LFMM), wood in the residential sector, geothermal heat pumps and distributed (grid-connected) solar photovoltaics in the residential and commercial sectors, and solar hot water heating in the residential sector. In addition, there are several areas, primarily nonelectric and off-grid electric applications that are not represented in NEMS. They include direct applications of geothermal heat, several types of solar thermal use, and off-grid photovoltaics. For the most part, the expected contributions from these sources are confined to niche markets; however, as these markets develop in importance they will be considered for representation in NEMS.

The number and purpose of the associated technology and cost characteristics vary from one RFM submodule to another depending on the modeling context. For example, renewable resources such as solar, wind, and geothermal energy are not fuels; rather, they are inputs to electricity or heat conversion processes. Consequently, the Solar, Wind, and Geothermal Submodules do not provide fuel product prices.

EIA's Office of Electricity, Coal, Nuclear and Renewables Analysis determines initial cost and performance values for renewable electricity technologies based on examination of available information. Several sources for the cost and performance characterizations were examined for use in this version of the RFM. These sources provide values for capital costs (excluding the construction financing and process and project contingency components that are provided in the EMM), fixed and variable operation & maintenance (O&M) costs, capacity factors, and construction lead times. All cost values are converted to 1987 dollars.

Provided below are summaries of the six RFM submodules that are used for producing the current forecasts: the Landfill Gas Submodule (LFG), the Wind Energy Submodule (WES), the Solar Energy Submodule (SOLAR), the Biomass Submodule, the Geothermal Energy Submodule (GES), and the Conventional Hydroelectricity Submodule (CHS). Each chapter concludes with information on the RFM archival package and EIA point of contact.

Landfill Gas Submodule (LFG)

The Landfill Gas Submodule provides annual projections of energy produced from estimates of U.S. landfill gas capacity. The Submodule calculates the quantity of LFG produced, derived from an econometric equation that uses Gross Domestic Product and U.S. population as the principal forecast drivers. The landfill gas capacity is estimated based on reported waste and gas production data and judgment about future trends in recycling. The submodule uses LFG supply curves to reflect competition between new landfill gas-to-electricity capacity and other technologies in each projection period. The supply curves account for the amounts of high, low, and very low methane producing landfills located in each EMM Region.

Wind Energy Submodule (WES)

The Wind Energy Submodule (WES) projects the availability of wind resources. Projected undeveloped wind resource availability, expressed as megawatts of capacity in each region, is passed to the EMM, which models the building and dispatching of wind turbines in competition with other electricity generating technologies. The wind turbine data are expressed in the form of energy supply curves. The supply curves provide the estimated maximum amount of turbine generating capacity that could be installed, given the available land area, average wind speed, and capacity factor. These variables are passed to the EMM in the form of nine time segments that are matched to electricity load curves within the EMM.[1]

---

[1] The nine time segments are derived from three 8-hour segments of the day for three seasons, winter, summer and off-peak (spring/fall averaged). The data represent average capacities based on empirical analysis.

Solar Submodule (SOLAR)

Two solar technologies are represented in NEMS, a 150-megawatt single-axis tracking grid-connected central station photovoltaic (PV) unit without energy storage, and a 100-megawatt central receiver (power tower) solar thermal unit (also called concentrating solar power or CSP) also without energy storage. Both technologies are grid-connected and provided by electric utilities, small power producers, or independent power producers.

PV and solar thermal electric cost and performance characteristics are defined consistently with characteristics of fossil and other fuels reside in the ECPDAT input file. Performance characteristics unique to solar technologies (such as season and region-dependent capacity factors), however, are passed to the EMM via the solar submodule SOLAR.

Biomass Submodule

The Biomass Submodule provides biomass resource and technology cost and performance characteristics for a biomass burning electricity generating technology to the EMM. The technology currently modeled is a direct combustion system. The submodule uses a regional biomass supply schedule from which the biomass fuel price is determined; fuel prices are added to variable operating costs, because there are no fuel costs in the structure of NEMS for renewable fuels. The biomass supply schedule is based on the accessibility of wood resources by the consuming sectors from existing wood and wood residues, crop residues, and energy crops. The LFMM also accesses the biomass supply curve to determine availability of feedstocks for production of cellulosic ethanol, biomass pyrolysis oils, and biomass-to-liquids. Projected feedstocks for production of sugar/starch based ethanol (primarily from corn/maize in the United States) are determined within the LFMM.

Geothermal Energy Submodule (GES)

The Geothermal Energy Submodule (GES) models current and future regional supply, capital cost, and operation and maintenance costs of electric generating facilities using hydrothermal resources (hot water and steam) and so-called near-field enhanced geothermal systems (EGS) sites, which are areas around the hydrothermal sites with high temperatures but less fluid. The data are assembled from 125 known hydrothermal sites and the 125 corresponding near-field EGS areas, each represented by information which reflects the specific resource conditions of that location. The GES generates a three-part geothermal resource supply curve for geothermal capacity for each region in each forecast year, for competition with fossil-fueled and other generating technologies.

Conventional Hydroelectricity Submodule (CHS)

The Conventional Hydroelectricity Submodule (CHS) models the supply (megawatts), capital cost, and operation and maintenance costs of conventional hydroelectric power available from adding new hydro generating capacity in increments of 1 megawatt or greater to (a) new sites without dams, (b) sites with existing dams but without hydroelectricity, and (c) existing hydroelectricity sites able to accommodate additional capacity. The CHS uses the Idaho Hydropower Resource Economics Database (IHRED). The CHS does not account for pumped storage capacity, increments of capacity less than 1 megawatt, potential available from refurbishing and upgrading existing hydro capacity, or capacity available from new in-stream, off-shore, or ocean technologies. Within each NEMS region, for each NEMS cycle, the CHS first identifies additional hydro capacity available at or below an avoided cost specified by the EMM,

then segments the available capacity into three cost categories: least, mid, and highest cost. The CHS then submits the megawatts of available capacity, expressed as average capital cost and operation and maintenance costs, each weighted by nameplate capacity, and capacity factors to the EMM for each of the three cost categories. After projecting capacity change decisions, the EMM informs the CHS of required decrements to potential available for selection in the next NEMS cycle.

Capacity credit for intermittent generation

Within the EMM, each region must have enough generating capacity installed to satisfy peak load requirements plus a regional reserve margin. For operator dispatched capacity types, the summer-rated capacity for each generator unit is used to determine the contribution provided to the reserve margin requirement. However, non-dispatched, intermittently available generating capacity, such as wind turbines or solar electric facilities, will not always generate during peak demand periods, and thus cannot contribute its full rated capacity to satisfy the reserve margin requirement.

Because there is a significant probability that at least some intermittent generators will be available during peak demand periods as well as a significant probability that some portion of operator dispatched capacity will not be available during this time, intermittent generators can contribute some fraction of their rated capacity to the reserve margin. This fraction, referred to as the capacity credit, is a function of the correlation between the temporal generation pattern of the resource and the peak load periods, as well as the fraction of intermittent generation compared to total regional output. That is, a wind turbine in a region where the wind typically blows strongly during the peak load period will contribute more to meeting peak-load system reliability than a wind turbine in a region with typically light peak-load winds. However, as wind or solar constitutes more of the system capacity, the variability of its peak-load operation will have a decreasingly beneficial effect on system reliability.

The capacity credit for intermittent generators is determined in NEMS as a function of the estimated average contribution that all units of that type (wind or solar) will provide to meeting an assumed system reliability goal of 99.999% availability (that is, the system should have enough generation capacity installed to be able to meet full load requirements 99.999% of the time, sometimes approximated as achieving 1 hour of load shortage in 10 years or 87,600 hours of operation). This contribution is, in turn, largely determined by the average, peak-load period capacity factor for the intermittent capacity, the standard deviation about that average, the degree to which the output at each individual site in a region is correlated with the output at other sites, and the reliability characteristics of the operator-dispatched (conventional) capacity in the region.

The peak-load period capacity factor for each intermittent generator is determined as described in the Wind and Solar Module chapters of this report. The normalized standard deviations for wind and solar plants are exogenously determined. The inter-site output correlation factors are also exogenously determined on a regional basis. The standard deviation for each conventional capacity type is calculated from the user-specified forced-outage rates, based on a binomial distribution:

$$S = C \times \sqrt{\frac{(P \times (1-P))}{N}}$$

Where C is the installed capacity of a specified type as calculated for that year, *P* is the forced outage rate (variable name UPFORT in the ECPDAT file), and N is the number of units for the specified plant type as calculated for that year and region.

The standard deviation of total capacity of all conventional types is

$$S_{Conventional} = \sqrt{S_1^2 + S_2^2 ... + S_n^2}$$

where S_n is the standard deviation for the nth capacity type.

The standard deviation for all intermittent units of a specified type (wind, solar thermal, or photovoltaic) is determined as

$$S_{Intermittent} = C \times \sqrt{N * s^2 + (N^2 - N) * R * s^2}$$

where *s* is the technology-specific normalized standard deviation of hourly output for intermittent resource facilities (INTSTDDV variable in the WESAREA file), *N* and *C* are as above (for intermittent rather than conventional capacity types), and *R* is the regional correlation factor for intermittent resources (INTREGCRL variable in the WESAREA file).

The total standard deviation of all generation (conventional and intermittent) is then calculated as

$$S_{Total} = \sqrt{S_1^2 + S_2^2 ... + S_n^2 + S_{Intermittent}^2} \text{ ,}$$

where S_n is as above, and $S_{Intermittent}$ is the total standard deviation for the intermittent capacity type being evaluated (wind, solar thermal, or photovoltaic).

The reliable capacity is then calculated excluding the intermittent capacity, then again including all capacity types using

$$C_{reliable} = \left(\sum C_{ave,n} \right) - Z \times S \text{ ,}$$

where $C_{ave,n}$ is the total annual average capacity for the nth capacity type and is evaluated for conventional-only capacity types and then again for conventional plus intermittent capacity types. For conventional resources, average capacity is the installed summer capacity multiplied by one minus the forced outage rate. For intermittent resources, it is the installed capacity times the peak-load period capacity factor. *Z* is the statistical parameter for the number of standard deviations in a normal distribution that are needed to account for a specified fraction of the area under the distribution curve, specified as variable UPINTZ in the ECPDAT file[2], and *S* is as calculated above for $S_{conventional}$ or S_{Total} as appropriate for the conventional-only or the total reliable capacity calculation.

Finally, the capacity credit (*U*) for the intermittent resource is calculated as

---

[2] For AEO2014, the default Z value of 3.19 is used to represent 99.93% of the area under the Gaussian normal distribution. The use of 99.93% to represent 99.999% reliability is explained in Appendix 1-A.

$$U_{Intermittent} = \frac{C_{reliable,Total} - C_{reliable,Conventional}}{C_{installed,Intermittent}}$$

where $C_{reliable}$ is as above for total and conventional-only generation, and $C_{intalled,Intermittent}$ is the installed, nameplate capacity of the intermittent resource being evaluated (wind, solar thermal, or PV). Note that the capacity credit for each intermittent resource is evaluated separately. As a given intermittent resource is calculated, the other two are included in the "conventional capacity" calculations, using the capacity credit from the previous model iteration to determine availability.

The resulting capacity credit is the average value for all intermittent units of the specified type in that region in the current year. This value is used by the EMM to determine total intermittent capacity to count toward the regional reserve margin. Because of the intra-regional power output correlation factor for the intermittent resources, the marginal capacity credit (that is, the contribution to reserve margin of the last unit built) actually declines, thus reducing the average capacity credit with increasing penetration. For purposes of capacity planning in NEMS, however, the intermittent plant vintage does not affect the calculation, and each plant (the first through the last built) receives the average capacity credit for that resource type.

Also, because the capacity credit is only calculated for the current year's installed capacity, it is not prospective, and the same number is evaluated within the EMM regardless of the amount of capacity ultimately constructed in the following year(s). While this approximation is reasonable if the annual capacity additions for the resource are small, it can significantly over-estimate the capacity credit in scenarios that result in the rapid build-up of intermittent renewable resources. Therefore, the maximum limit on the regional fraction of intermittent generation is allowed to increase by 5 percentage points per year, but cannot exceed 40% nor fall below 20%. That is, NEMS computes the maximum historical fraction of intermittent generation and then adds 0.05. If this value exceeds 0.40 (as specified by the UPINTBND in ECPDAT), it is set to 0.40. If this value falls below 0.20 (actually specified as one half of the ultimate upper bound on intermittent generation or UPINTBND/2), it is set to 0.20. This expanding limit, based on EIA expert judgment, serves to ensure that capacity credit impacts are reasonably accounted for and to simulate the time needed for regional system operators to adjust operating procedures to accommodate large amounts of intermittent generation. The final regional limit of 40% intermittent generation accounts for the uncertain system costs required to accommodate such large amounts of non-dispatched generation.

The statistical approximations used to describe the variance in output from both conventional and intermittent resources are reasonable over a wide range of capacity configurations. However, with extreme levels of intermittent capacity, it is possible for the algorithm to produce a negative capacity credit for intermittent resources. Since the instantaneous or long-term output of real-world intermittent resources cannot fall below zero, these resources cannot have a capacity credit less than or equal to zero. Therefore, the capacity credit is constrained to be greater than zero.

An additional impact of intermittent generation on reliable grid operations is the potential for excessive generation during off-peak periods. Since solar resources do not operate during the lowest-load hours

(which are typically at night), the treatment of this impact in NEMS is described in the chapter of the report on the Wind module.

Representation of depreciation for renewables-fueled generating technologies

For most central station electricity generating technologies, NEMS assumes a 20 year tax life over which the capital is depreciated. However, nuclear technologies are assigned a 15 year tax life. Renewables-fueled central station electricity generating technologies—including biomass, geothermal, hydroelectric, landfill gas, solar (photovoltaic and thermal) and wind—are assigned 5-year tax lives and 5-year double declining balance depreciation in NEMS. The basis for biomass, geothermal, solar, and wind enjoying 5 year double declining balance depreciation is a consequence of the Economic Recovery Tax Act of 1982 (ERTA, P.L. 97-34); see Internal Revenue Code, subtitle A, Chapter 1, Subchapter B, Part VI, Section 168 (e)(3)(vi)(1994) – accelerated cost recovery.

Archival Media
The RFM is archived as part of the National Energy Modeling System production runs.

Model Contact
Chris Namovicz, Team Leader
Renewable Electricity Analysis Team,
Office of Electricity, Coal, Nuclear, and Renewables Analysis
U.S. Energy Information Administration, EI-34
1000 Independence Ave., SW
Washington, DC 20585
Phone: (202) 586-7120
e-mail: chris.namovicz@eia.gov

Report organization

Subsequent chapters of this report provide detailed documentation of each of the RFM's six working submodules. Each chapter contains the following sections:

- Model Purpose —a summary of the submodule's objectives, detailing input and output quantities, and the relationship of the submodule to other NEMS modules
- Model Rationale —a discussion of the submodule's design rationale, including insights into assumptions used in the model development process, and alternative modeling methodologies considered during the submodule development phase
- Model Structure—an outline of the model structure, using text and graphics to illustrate the major model data flows and key computations

Appendices—supporting documentation for input data and parameter files currently residing on the EIA computer network. Appendix A in each RFM submodule chapter lists and defines the input data used to generate parameters and endogenous forecasts. Appendix B contains a mathematical description of the computation algorithms, including model equations and variable transformations. Appendix C is a bibliography of reference materials used in the model development process. Appendix D consists of a model abstract. Appendix E discusses data quality and estimation methods.

Appendix 1-A: Background information on deriving the capacity credit for intermittent generation

The algorithm used to represent the capacity credit for intermittent resources is premised on the notion that the initial wind plants introduced into a power coordination region (or control area) can contribute to reliable capacity needs (that is, earn "capacity credit") roughly in proportion to the wind's peak-load capacity factor in that region. However, as grid penetration increases, the capacity credit for the wind plants decreases, approaching a zero marginal capacity credit at sufficient penetration levels. Viewed another way, the introduction of wind capacity can increase the effective load-carrying capacity of a system, but eventually reaches a "saturation" level at which addition of new wind capacity does not increase the effective load-carrying capacity of the region.

To represent this saturation effect, EIA developed a statistical model of capacity adequacy for generation reliability. This model provides the basis for the algorithm to calculate the capacity credit assigned to intermittent generation in NEMS, and is described below.

Understanding the fundamental issue of assuring capacity adequacy with large amounts of non-dispatched power with a significant random component can be accomplished with a greatly simplified statistical representation of the generating resources on a grid.

Establishing the statistical foundation for such a model requires closer examination of the statistical properties of each component of the system. In this case, we are concerned with two basic types of components: 1) conventional, dispatchable generation capacity including steam plants (using nuclear, biomass, coal, or other fossil fuels), combustion turbines (simple and combined cycle), and hydroelectric power (primarily those with seasonal water storage, as "run-of-river" plants have a significant intermittent component) and 2) intermittent generation, including wind and solar.

In understanding how an uncontrollable, and to large extent uncertain resource like wind can contribute at all to regional reliability reserves, it is important to remember that no single generation resource is perfectly reliable. In addition to planned outages for maintenance, which can be scheduled to coincide with periods of low demand, every plant experiences forced outages. Thus there is some significant probability that the wind generation will be "available" (that is, the wind blowing) at the same time some fraction of dispatched capacity is unexpectedly offline. Forced outage rates vary from plant to plant and are a function of technology type, plant vintage, and maintenance regime. Although some equipment failure (or other reliability incident) may result in a partial outage or capacity derating, the statistical model developed in this appendix makes the simplifying assumption that a conventional plant outage is a Bernoulli trial: that is, there is a chance that plant is either fully operational or fully out-of-service, but not in some intermediate state (such as operable at a derated capacity level). Note that is not important to calculating generation adequacy that the plant actually operate at full capacity (or even operate at all), but simply that its full capacity is (or is not) available if needed.

Although a typical conventional plant may have a forced outage rate of 5% (or conversely an availability rate of 95%), it is assumed here that utilities want to achieve an overall system availability rate of 99.999% ("five nines of reliability" or "one hour of outage in 10 years"). Obviously, it is not possible to achieve more than 95% system reliability if you are using a single typical plant. What's the reliability if

the system gets two completely redundant units (each capable of providing 100% load at 95% availability)? This is the probability that both units are operating (0.95 x 0.95=0.9025) plus the probability that unit B is operating while unit A is out (0.95 x 0.05=0.0475) plus the probability that unit A is out while unit B is operating (also 0.0475). The two-generator system achieves 99.75% availability to serve load equal in size to the single generator. Note that simply doubling the capacity of the single unit would not improve system reliability, as there would still only be a 95% chance of maintaining load (average capacity improves the same in both cases, but system reliability only improves when the number of generators is increased).

Building a contingency table to calculate the probabilities of all possible on/off states of each generator in a system of more than a handful of units would be quite time consuming. However, because of the Bernoulli nature of the probabilities, the statistical behavior of the system is already fairly well described. Specifically, if we can assume individual units of equal size and availability, then we can assume an average availability for total capacity of 95% (or whatever the common availability is). The 99.999% availability level is then the mean available capacity minus 4.265 standard deviations (that is, 99.999% of the area under a standardized normal "bell" curve is within 4.265 standard deviations of the mean). For a collection of Bernoulli trials, the normalized standard error of a sample N (in this case, number of plants within a region of interest) with probability P (in this case, representing the availability) is from the binomial distribution:

Eq. 1) $S = \sqrt{\dfrac{(P * \bar{P})}{N}}$, where $\bar{P} = 1 - P$

With a sufficiently large number *N* of trials (each representing a generator unit), the binomial distribution approaches the Gaussian normal distribution, and the standard error can be used as an estimate of the Gaussian standard deviation. Multiplying by the average capacity converts the normalized standard deviation to the capacity standard deviation.

Of course, we need to account for multiple generators of varying capacity and reliability. The overall standard deviation of a multi-plant system is estimated as follows:

Eq. 2) $S_T = \sqrt{S_1^2 + S_2^2 ... + S_n^2}$,

where S_n is the standard deviation representing the nth plant.

For a binomial distribution, the standard error is inversely proportional to the square root of the number of units. Thus reliability is improved by adding more redundancy (that is, more units) into the generation mix, as indicated in the simple example at the beginning of this appendix. Adding the same amount of capacity with a single, large unit improves reliability somewhat less than adding the same amount of capacity with several smaller units.

The 99.999% reliability requirement is for the entire year, 24 hours a day, 7 days a week. In general, utilities are most concerned with having enough reliable capacity on-hand to meet peak load requirements (with the working assumption that if you have enough capacity to meet peak requirements, you should have more than enough to meet off-peak requirements). Peak load periods,

as modeled in NEMS, account for about 1.56% of all hours in a year. If it is assumed that the "1 hour in 10 years" of outage in a "five-nines" system occurs during the 1.56% of peak hours (the top 137 hours of load), then the system operator needs to maintain "1 hour in 10 years-of-peak-load-periods" reliability, or 1 hour in 1370 operating hours (137 hours per year for a 10 year period). Thus a targeted reliability of 99.93% for peak-load should be sufficient to maintain "five-nines" of reliability for all load hours – assuming that there will be abundant excess off-peak capacity to cover both forced outages and planned maintenance.

Although conventional generators do have occasional partial outages, modeling single-unit availability as a Bernoulli trial is a reasonable approximation of actual operations. The availability of wind generation to the grid, however, cannot reasonably be modeled as an all-or-nothing event. The power output from a typical wind turbine as a function of ambient wind speed is shown below. A wind turbine may have zero output 10% or 20% of the time, when the wind is either too light to move the blades (common, shown as range "A") or too strong to allow the mechanism to operate without damage (rare, shown as range "D"). However, the rest of the time (that is, 80% to 90% of the time) its output fluctuates more-or-less continuously as a non-linear function of the wind speed.

Typical Power Curve
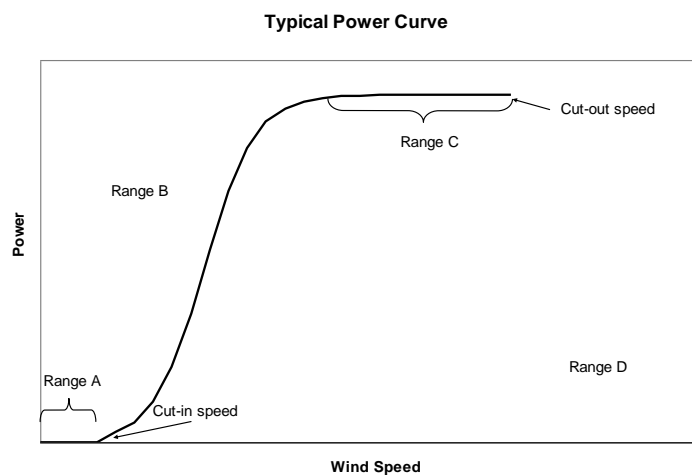
Wind speeds are not evenly distributed at a given site. Although the exact distribution of wind speeds varies from location to location, even within a "wind resource class", the Weibul distribution with a "shape" parameter of around 2 is frequently cited as a typical form. The figure below shows a Weibul probability density function with a shape parameter of 2 (also known as a Rayleigh distribution) overlaid on the previous power curve example. The resulting distribution of wind power output (that is, the average of the wind power curve as weighted by the Weibul probabilities at each wind speed) is not characteristic of a binomial, Weibul, or other common probability distribution. However, with sufficient numbers of wind plants, one would expect the aggregate statistical distribution of the output to assume an increasingly Gaussian form.

Weibul (Rayleigh) Probability Distribution Function and Typical Wind Power Curve
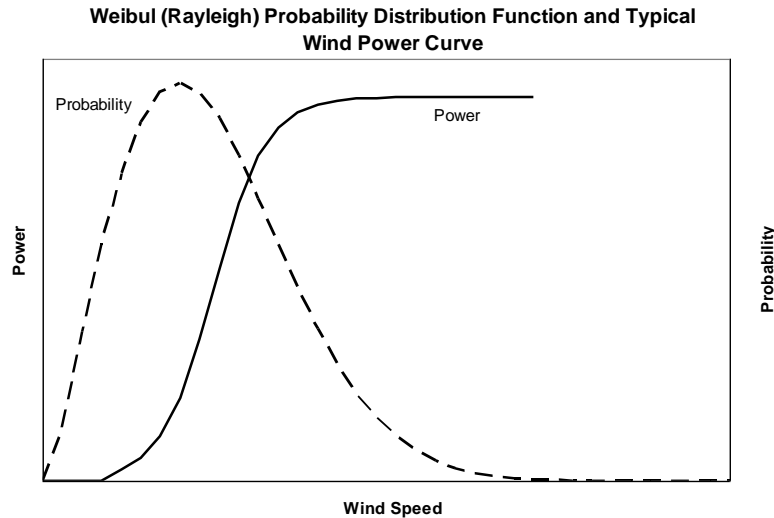
Since the standard deviation of power output for a wind turbine or wind plant cannot be determined analytically, it is estimated through simulated output of a typical wind turbine power curve[3] in a Class 6 wind resource. The simulated statistical parameters for the single turbine are directly scaled-up to represent the full site (assuming that, over the timeframe of interest, hourly-to-daily, there is perfect correlation among all turbines in a relatively compact 50 megawatt (MW) site). The simulation indicates an average standard deviation in output of 38% of the nameplate capacity. So for a 50 MW site, average hourly output would have a standard deviation of 19 MW. For solar resources, a normalized standard deviation of 10% of nameplate capacity is assumed.

Of course, any significant penetration of wind in a larger system is going to consist of more than one wind plant. One way to model larger increments of wind capacity would be simply to scale the single-plant model to a larger composite size. Scaling the single plant implies that each individual turbine in the composite plant is subject to essentially the same wind regime (that is, simultaneous sampling from the same distribution) as shown here:

Eq. 3) $S_T = \sqrt{(N * S)^2}$

Where N is the number of wind farms, each with the same annual average capacity factor and standard deviation (S). While this is a reasonable assumption when scaling up from a single turbine to a 50 MW wind farm spread over 325 square (sq.) kilometers (km) of land (about 18 km by 18 km), for a region with multiple wind farms separated by hundreds of miles, it seems more reasonable to assume that the output of each farm is not perfectly correlated with the output of the other farms, at least over a time period of interest to grid reliability (one hour to one day).

---

[3] Turbine power curve used in the simulation is a normalized approximation of the Vestas V-47 wind turbine. This turbine was selected because of availability of independently verified data through the DOE/EPRI Turbine Verification Program and the substantial installed capacity base of that model in the United States. The use of the characteristics of this turbine is not an endorsement or statement of technological preference on the part of EIA.

In the limiting case of multiple wind farms with uncorrelated output, we can use Equation 2 to determine the overall standard deviation of the system, using the statistical parameters for each wind plant. To simplify the math, we could further assume that for wind farms of equal size, we have equal capacity factors and standard deviations. That is, we are sampling from different populations with the same statistical parameters (mean and variance). The standard deviation of the thus simplified Equation 2 is

Eq. 4) $S_T = \sqrt{N * S^2}$

So for highly correlated wind units (such as the output of a single wind plant scaled to higher levels of assumed wind capacity), the standard deviation is directly proportional to the total number of installed units. For completely uncorrelated wind units (such as individual wind plants placed in entirely different climate zones), the standard deviation is proportional to the square-root of the number of units. Conceptually, this is the same result as we had for the conventional units: multiple smaller units provided better reliability than a single unit of equivalent capacity. However, in the case of the conventional units, we had an implicit (and reasonable) assumption of independence for the availability of each unit (that is, an outage of one unit would not correlate with the probability of an outage from any other unit).

Equation 3 assumes perfect correlation among all wind sites. Equation 4 assumes no correlation among any wind site. In the real world, there is likely some correlation among sites, but not perfect correlation. Partial correlation between two populations (populations 1 and 2) is statistically described by the population standard deviations and two additional parameters: the correlation coefficient ($R_{1,2}$) and the, covariance ($C_{1,2}$) which are related as follows:

Eq. 5) $C_{1,2} = R_{1,2} * S_1 * S_2$

Where *S* is the standard deviation for the indicated population. The total standard deviation of the total output from two partially correlated populations is

Eq. 6) $S_T = \sqrt{S_1^2 + S_2^2 + 2 * R_{1,2} * S_1 * S_2}$

Generalizing to a system with N windy sites, each site equally correlated with each other site, and otherwise drawn from different populations with the same population parameters (that is, $S_1=S_2=S_N$, per our previous simplifying assumption), we get

Eq. 7) $S_T = \sqrt{N * S^2 + 2 * \begin{bmatrix} N \\ 2 \end{bmatrix} * R * S^2}$,

where $\begin{bmatrix} N \\ 2 \end{bmatrix}$ ("*N* choose 2") represents the number of combinations of 2 items (pairs) that can be formed from a sample of *N* items.

The "*N* choose 2" term of Equation 7 is a non-linear term that increases about half as fast as the quadratic term from Equation 3, or more precisely, $\begin{bmatrix} N \\ 2 \end{bmatrix} = \dfrac{N^2 - N}{2}$, so when *R* is 1, Equation 7 reduces to Equation 3. Thus, as might be expected, partial correlation provides for non-linear growth in the standard deviation of the system, approaching the growth observed for perfect correlation as *R* approaches 1 (where 1 is perfect correlation), and approaching perfect independence as *R* approaches 0 (when *R* is 0, Equation 7 reduces to Equation 4).

With the assumption of normal probability distributions for large aggregations of both conventional and intermittent capacity, Equation 2 can be extended to modeling of a highly diverse generating stock that includes conventional units of different size and reliability, as well as intermittent units:

Eq. 8) $S_T = \sqrt{S_1^2 + \dots + S_N^2}$,

where each S_N represents the standard deviation of a class of units with substantially similar statistical characteristics. Examples of such unit classes could include all simple combustion turbines, all wind farms within a particular geographic range, coal steam units with common technology, and so forth.

In NEMS, each electric generation technology is assigned a class-typical forced outage rate. Although over 50 technology types are represented, over half of these are variations on coal-steam plants with different combinations of emission control technologies. The statistical outage properties for each dispatchable technology can be characterized by Equation 1. Table 1 shows the availability parameters needed for each major capacity type grouping in the EMM.

Table 1A. Forced outage rate by major group of NEMS capacity type

Plant Type	Forced Outage Rate (fraction of annual hours)
Combined Cycle	0.055
Coal	0.066
Nuclear	0.070
Combustion Turbine	0.036
Hydro	0.036
Municipal Solid Waste	0.066
Other Steam	0.071
Biomass	0.066
Geothermal	0.066
Intermittent[*]	0.036

[*] - Not used in this calculation, intermittent capacity credit is calculated as described in text, not based on forced outage rate.

Source: Office of Electricity, Coal, Nuclear, and Renewable Analysis ECPDAT file.

To derive the capacity credit for wind, the standard deviation for each conventional capacity type is then determined through Equation 2, using only the operator-dispatched capacity. The derived capacity group standard deviations are then used in Equation 8 to determine the total standard deviation for all conventional capacity ($S_{conventional}$).

Peak-load system reliability without intermittent capacity is determined from the reliable load carrying capacity of the conventional units at the 99.93% confidence level (corresponding to a Z statistic of 3.19 standard deviations):

Eq. 9) $C_{99.93\%} = C_{ave} - 3.19 * S_{conventional}$,

where C_{ave} is the average available capacity (sum of nameplate times availability for each unit type).

Using the conventional capacity standard deviation from above, the total system standard deviation, S_{total}, is determined based on the wind correlation assumption and the assumed standard deviation for each wind plant:

Eq. 10) $S_{total} = \sqrt{S_{conventional}^2 + (N^2 + 2 * \begin{bmatrix} N \\ 2 \end{bmatrix} * R) * S_{wind}^2}$

The reliable load-carrying capacity of the total system (with intermittent resources) is then calculated from Equation 9, substituting the total standard deviation (S_{total}) for the conventional standard deviation and using the total system average available capacity. Note that the contribution to average available capacity for intermittent resources is the sum of the nameplate capacities times the peak-load period capacity factor. The average capacity credit for wind or other intermittent resource (U_{wind}) is then the incremental improvement in system capacity from the intermittent resources divided by the total installed intermittent resource:

Eq. 11) $U_{wind} = \dfrac{C_{reliable,total} - C_{reliable,conventional}}{C_{installed,wind}}$,

where $C_{reliable}$ is the reliable load carrying capacity for operator-dispatched capacity (conventional) and all capacity including intermittent capacity (total) and $C_{installed,wind}$ is the nameplate wind capacity installed.

The regional wind power output correlation coefficient (R in the above system of equations) used in the model is derived from data provided by the National Renewable Energy Laboratory (NREL), using a resource data pre-processor for the REeDS model. Parameters are provided in Table 2, Regional power correlation factors. Note that for the solar technologies, it is assumed that regional correlation is relatively high, given the strong diurnal solar cycle that is consistent across regions of the size considered.

Table 2. Regional power correlation factors (dimensionless)

Region	Onshore Wind	Offshore Wind	CSP	PV
1	0.89	0.89	0.7	0.7
2	0	0	0.7	0.7
3	0.84	0.84	0.7	0.7
4	0.86	0.86	0.7	0.7
5	0.74	0.74	0.7	0.7
6	0	0	0.7	0.7
7	0	0	0.7	0.7
8	0.69	0.69	0.7	0.7
9	0.79	0.79	0.7	0.7
10	0.77	0.77	0.7	0.7
11	0.73	0.73	0.7	0.7
12	0.96	0.96	0.7	0.7
13	0.87	0.87	0.7	0.7
14	0	0	0.7	0.7
15	0.8	0.8	0.7	0.7
16	0.55	0.55	0.7	0.7
17	0.77	0.77	0.7	0.7
18	0.89	0.89	0.7	0.7
19	0.87	0.87	0.7	0.7
20	0.77	0.77	0.7	0.7
21	0.87	0.87	0.7	0.7
22	0.89	0.89	0.7	0.7

Sources: Wind: National Renewable Energy Laboratory, Solar: estimates based on EIA expert judgment. For regional definitions, see http://www.eia.gov/forecasts/aeo/pdf/f2.pdf.

While assuming a constant correlation between all sites within a region provides a simple, tractable model of these effects, it is important to note that actual inter-site correlation is likely variable across space and time. Sites that are physically closer to each other will have more highly correlated outputs over shorter time spans. Sites that are more distant from each other will have lower correlation, which may only become evident over extended periods of time (seasons or years). Furthermore, this correlation is also a function of resource development. If few available wind resources have been developed, a new plant can easily be sited in a location more distant (and hence less correlated) from existing plants. But as development increases, plants will eventually be built closer together, thus increasing the correlation.

2. Landfill Gas (LFG) Submodule

Model purpose

The main purpose of the Landfill Gas (LFG) Submodule is to provide EMM with annual projections of electric power capacity of landfill-gas-to-energy plants. The submodule uses the quantity of municipal solid waste (MSW) that is produced, the proportion of MSW that will be recycled, and the emission characteristics of three types of landfills (high, low, and very low methane-producing), to produce forecasts of the future electric power capacity from landfill gas.

It is assumed that no new mass burn waste-to-energy facilities will be built and operated during the forecast period in the United States. It is also assumed that mass burn waste-to-energy facilities that are already operational will continue to operate and retire as planned throughout the forecast period. Overall generation, however, will increase due to expansion of LFG facilities. Moreover, these facilities use both biogenic and non-biogenic waste for electricity generation. Only the biogenic portion is included in the renewable total. While the renewable component of the waste has been diminishing, the forecast assumes it remains constant in the future.

Relationship of the LFG Submodule to other models

The LFG submodule passes capacity estimates, cost, and performance characteristics of landfill-gas-to-electricity technology to the EMM for capacity planning decisions. LFG cost and performance characteristics reside in RFM's input file MSWDAT. The LFG submodule also takes inputs from other NEMS modules, including annual real Gross Domestic Product (GDP) and the total U.S. population projection, both of which come from the NEMS Macroeconomic Activity Module (MAM).

Modeling rationale

Theoretical approach

The modeling approach involves calculation of a three-step supply curve that is based on the number of high-, low-, and very low-methane-producing landfills located in each electricity market module region. An average cost of electricity production for each type of landfill is calculated using gas collection system and electricity generator costs and characteristics developed by the U.S. Environmental Protection Agency's (EPA) Energy Project Landfill Gas Utilization Software (E-PLUS). [4]

---

[4] 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.

Fundamental assumptions

MSW Quantity Projections

The amount of methane available is calculated by first determining the amount of total waste generation excluding composting and incineration through 2040 and applying assumptions regarding the amount of waste that is recycled against this waste stream.

The definition of MSW for the regression in the LFG Submodule is consistent with that used by EPA and defined in Subtitle D of the Resource Conservation and Recovery Act. In this definition, municipal solid waste includes discarded durable goods, nondurable goods, containers and packaging, food wastes, and yard trimmings from the residential, commercial, institutional, and industrial sectors. The EPA definition of MSW does not include everything that might be landfilled in Subtitle D landfills or burned, such as municipal sludge, nonhazardous industrial wastes, construction and demolition wastes, urban wood waste and tires. These wastes are often disposed alongside those wastes formally defined as MSW. To capture these other materials as part of the projections, the EPA estimates (Franklin, 1994) were compared to the higher quantities reported in the annual BioCycle survey (BioCycle, 1993). The average difference between the EPA and BioCycle values for historical years was used as a multiplicative adjustment factor applied to the regression results. In effect it represents the difference between a regression-estimated value and the value estimated from the survey data. These same values for total MSW are also used in estimating landfill gas use, discussed later in this section. As noted earlier, EIA only includes electricity generated from biogenic waste in the renewable total. An internal analysis using EPA data was performed to determine the renewable share.

Estimation of Recycling Quantity

It is assumed that recycling accounts for 35 percent of the total waste stream in 2005 and linearly increases to 50 percent by 2010. The recycling portion is held constant at 50 percent after2010. This is consistent with EPA's goals of nationwide recycling targets. This is considered to be an ambitious but achievable goal since some communities in the United States are already recycling at 50 percent levels.

Projected Quantity of Methane Generation

The quantity of waste that will be landfilled through 2040 is used as supply input for a slightly modified EMCON Methane Generation Model.[5] The EMCON model characterizes waste into three categories: readily, moderately, and slowly decomposable material – based on the emission characteristics of each type of waste. It then calculates methane emissions over the decomposition cycle associated with each waste characteristic. The model and emission parameters are the same as those used in calculating historical methane emissions in EIA's *Emissions of Greenhouse Gases in the United States 2003*.[6,7]

---

[5] D. Augenstein, "The Greenhouse Effect and U.S. Landfill Methane", Global Environmental Change, December 1992, pp. 311-328.

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

[7] U.S. Energy Information Administration, Documentation for Emissions of Greenhouse Gases in the United States 2002, DOE/EIA-0638(2002), Washington, DC, January 2004, pp.79-84.

The yearly methane yield for each landfill type—high, low, and very low methane production—and yield type—readily, moderately, and slowly decomposable waste—is calculated as the ratio of the decomposition yield rate to the methane production limit, based on the data obtained for 156 operating landfills contained in the Governmental Advisory Associate's METH2000 database.[8]

Constructing the Supply Curve

The production cost of electricity for high, low, and very low methane-yielding sites was calculated by constructing a model of a representative 100-acre by 50-feet deep landfill site and by applying methane emission factors for high, low, and very low methane emitting wastes (Table 2-1).

Table 2-2 shows the cost of electricity for the three landfill types and the regional distribution of landfill capacity. In order to construct Table 2-2 the Governmental Advisory Associate's METH2000 database was used. This database has data on 156 operating landfills from which ratios of high, low, and very low methane yielding sites for each state can be calculated. The state level ratios of the different landfill types are then mapped to North American Electric Reliability Corporation (NERC) regions allocating capacities to the different NERC regions on the basis of their shares of state areas. Annual methane production for a hypothetical site differs with each yield assumption. Therefore, each landfill type has associated differences in terms of generator size, number of wells, cost of gas cleanup, piping, and other gas collection and generating requirements. These variations lead to different production costs of electricity due to differences in material cost as well as in economies of scale. In general, high methane yield sites produce electricity at a lower cost per kilowatt-hour than lower yielding sites. The available supply of methane at each yield assumption for each region as well as national electricity prices are shown in Table 2-2.

---

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

Table 2-1. Methane production parameters for high, low, and very low yield sites

Methane Yield Parameters	High Yield	Low Yield	Very Low Yield
Fraction readily decomposable	0.040	0.040	0.040
Fraction moderately decomposable	0.450	0.450	0.450
Fraction slowly decomposable	0.052	0.052	0.052
Rate of methane yield – readily decomposable (ft^3/pound)	4.50	2.75	1.38
Rate of methane yield – moderately decomposable (ft^3/pound)	3.55	1.95	0.98
Rate of methane yield – slowly decomposable (ft^3/pound)	0.50	0.29	0.16
Lag for methane generation from readily decomposable waste (years)	0	0	0
Lag for methane generation from moderately decomposable waste (years)	2	2	2
Lag for methane generation from slowly decomposable waste (years)	5	5	5
Production limit for readily decomposable waste (years)	3	4	4
Production limit for moderately decomposable waste (years)	10	20	20
Production limit for slowly decomposable waste (years)	20	40	40

Sources: U.S. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2003*, DOE/EIA-0573(2003), Washington, DC, December 2004.

U.S. Energy Information Administration, Documentation for *Emissions of Greenhouse Gases in the United States 2002*, DOE/EIA-0638(2002), Washington, DC, January 2004, pp.79-84.

Parameters for very low yield site assumed to be 50 percent of low yield site values.

Table 2-2. Landfill gas to energy supply by region

	Megawatts of Potential Capacity					Percent of National Capacity			
Region	High Yield	Low Yield	Very Low Yield	Total		High Yield	Low Yield	Very Low Yield	Total
1	14	21	320	354		0.3	0.4	6.3	7.0
2	16	24	159	198		0.3	0.5	3.1	3.9
3	8	13	67	87		0.2	0.3	1.3	1.7
4	4	37	165	206		0.1	0.7	3.3	4.1
5	25	38	56	119		0.5	0.8	1.1	2.4
6	13	20	43	76		0.3	0.4	0.9	1.5
7	5	8	17	30		0.1	0.2	0.3	0.6
8	20	30	65	116		0.4	0.6	1.3	2.3
9	42	63	322	426		0.8	1.2	6.4	8.4
10	7	11	97	114		0.1	0.2	1.9	2.3
11	61	92	647	800		1.2	1.8	12.8	15.8
12	5	8	67	80		0.1	0.2	1.3	1.6
13	23	35	188	246		0.5	0.7	3.7	4.9
14	10	14	124	148		0.2	0.3	2.5	2.9
15	12	17	152	181		0.2	0.3	3.0	3.6
16	12	18	160	190		0.2	0.4	3.2	3.8
17	1	1	62	63		0.0	0.0	1.2	1.3
18	2	2	124	127		0.0	0.0	2.5	2.5
19	1	1	60	61		0.0	0.0	1.2	1.2
20	156	235	739	1,130		3.1	4.7	14.6	22.4
21	26	39	183	248		0.5	0.8	3.6	4.9
22	0	0	30	30		0.0	0.0	0.6	0.6
U.S. Total	463	727	3,847	5,030		9.1	14.5	76.1	99.7

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear, and Renewables Analysis. For regional definitions, see http://www.eia.gov/forecasts/aeo/pdf/f2.pdf.

LFG Submodule structure

Submodule Flow Diagram

This section presents a flow diagram (Figure 1) of the LFG Submodule that shows the Submodule's main computational steps and data relationships.

Figure 1. Landfill gas submodule flowchart

```
                        ┌──────────────────────┐
                        │        START         │
                        │   (call from RFM)     │
                        └──────────────────────┘
                                   │
                                   ▼
                         ◇────────────────────◇
                        ╱  First year and first  ╲   yes
                        ╲      iteration         ╱ ────────────┐
                         ◇────────────────────◇               │
                                   │                           ▼
                                   │ no          ┌────────────────────────────┐
                                   │             │ Read input data from MSWDAT │
                                   │             │ cost (performance            │
                                   │             │ characteristic), waste       │
                                   │             │ source reduction factor,     │
                                   │             │ update input data            │
                                   │             └────────────────────────────┘
                                   │                           │
                                   │                           ▼
                                   │             ┌────────────────────────────┐
                                   │             │ Calculate landfill amount   │
                                   │             │ and projected methane yield │
                                   │             │ by landfill type and yield  │
                                   │             │ type for historical years   │
                                   │             └────────────────────────────┘
                                   │                           │
                                   │                           ▼
                                   │             ┌────────────────────────────┐
                                   │             │ Calculate percent recycled  │
                                   │             │ for forecast years          │
                                   │             └────────────────────────────┘
                                   │                           │
          ┌──────────┐            ▼◄─────────────────────────────┘
          │ GDP and  │   ┌────────────────────────────┐
          │population│──►│ Calculate waste stream for  │
          │from MAM  │   │ current year                │
          └──────────┘   └────────────────────────────┘
                                   │
                                   ▼
                         ┌────────────────────────────┐
                         │ Calculate yearly landfill   │
                         │ amount and projections for  │
                         │ methane yield by landfill   │
                         │ type and yield type for     │
                         │ forecast year               │
                         └────────────────────────────┘
                                   │
                                   ▼
                         ┌────────────────────────────┐
                         │ Calculate landfill gas      │
                         │ supply up to current year,  │
                         │ including historical supply │
                         └────────────────────────────┘
                                   │
                                   ▼
     ┌──────────────┐   ┌──────────────────┐   ┌──────────────┐
     │ Convert      │──►│ Calculate regional│──►│ Output to EMM│
     │ landfill gas │   │ landfill gas       │   └──────────────┘
     │ supply to    │   │ electric capacities│
     │ equivalent MW│   └──────────────────┘
     └──────────────┘
```

Key Computations and Equations

The LFG Submodule calculates a three-step supply curve that is based on the number of high, low, and very low yield methane producing landfills located in each electricity market module region. An average cost of electricity generation for each type of landfill is calculated using gas collection system and electricity generation costs and characteristics.

The amount of methane available is calculated by first determining the amount of total waste available, excluding composting and incineration, through 2040 and applying assumptions regarding the amount of waste that is recycled against this waste stream. It assumed that recycling accounted for 35 percent of the total waste stream in 2005 and linearly increases to 50 percent by 2010. The recycling portion is held constant at 50 percent from 2010 through 2040.

The quantity of waste that will be landfilled through 2040 is used as supply input for the methane generation model. The model calculates methane emissions over the decomposition cycle associated with each type of waste (readily, moderately, and slowly decomposable material).

The cost of electricity generation for high, low, and very low methane yielding sites is calculated by constructing a model of a representative 100-acre by 50-feet deep landfill site and by applying methane emission factors for high, low, and very low methane emitting wastes.

Formulae for some of these calculations are presented in Appendix 2B: Mathematical Description.

Appendix 2-A: Inventory of Variables, Data, and Parameters

This Appendix describes the variables and data inputs associated with the LFG Submodule. Table 2A-1 provides a tabular listing of model variables, input data, and parameters. The table contains columns with information on item definitions, modeling dimensions, data sources, and measurement units.

The remainder of Appendix 2-A consists of detailed descriptions of data inputs and variables, including discussions on supporting data assumptions and transformations.

Table 2A-1. NEMS landfill gas submodule inputs and outputs

Model Variable	Definition and Dimensions	Source	Units
INPUT DATA			
WHC	MSW heat content values in Census division r in year y	U.S. EPA	Btu/lb of MSW
UPHTRT*	LFG heat rate for electricity production	Government Advisory Associates Oak Ridge	Btu/kWh
UPMCF*	Capacity factor of a LFG plant	EPRI TAG	unitless
UPOVR*	Capital cost for a LFG plant	EPRI TAG	$/kW
UPFOM*	Fixed O&M cost for a LFG plant	EPRI TAG	mills/kWh
WVC	Variable O&M cost for a LFG plant	EPRI TAG	mills/kWh
SR	Annual source reduction factor	EIA staff	Percentage
a_1	Regression coeff. representing GDP dependency	Regressed by EIA	10^6ton/10^9\$
a_2	Regression coeff. representing population dependency	Regressed by EIA	10^6ton/10^6capita
α	waste stream adjustment factor	Determined by EIA	unitless
CALCULATED VARIABLES			
MC_GDP92C	Real gross domestic product for year y	Determined in MAM	Billion $
MC_N	U.S. Population incl. Overseas armed forces	Determined in MAM	10^6
Q	Quantity of energy from municipal solid waste for generation of electric power in EMM region n		MMBtu per year
WASTE_STREAM	Quantity of municipal solid waste produced in the U.S.		Million tons per year
WCAMSEL	MSW electric capacity for utilities in EMM region n in year y		Megawatts
WVCMSEL	Variable O&M cost of MSW electric generating capacity in EMM region n in year y adjusted for tipping fees		Mills/kWh

*Assigned in EMM input file ECPDAT.

MODEL INPUT: *WHC*

DEFINITION: Heat content in year *y*

Heat content values, measured in Btu per pound of MSW. Heat contents are national data and are assumed to be the same for each EMM region. The historical and projected percent composition of MSW was obtained from Franklin Associates for each of the main components of MSW. The main components of MSW include: paper and paper board, glass, metals, plastics, rubber and leather, textiles, wood, food waste, yard waste, other organics, and other inorganics. The Btu content was obtained for each material from EPA. The percentages and Btu contents were combined to provide an overall heat content per pound of MSW. Values for the years through 2000 were based on an assumed continuation of the historical trend. Beyond 2000, it was assumed that WHC remains level for the duration of the forecast horizon.

SOURCE: Franklin Associates, "Characterization of Municipal Solid Waste in the United States: 1997 Update," prepared for the U.S. Environmental Protection Agency, Municipal and Industrial Solid Waste Division, Office of Solid Waste, May 1998.

MODEL INPUT: *UPHTRT*

DEFINITION: Heat rate for LFG plants

The heat rate (Btu/kWh) is assumed to be constant for all EMM regions and years. For those plants that cogenerate electricity and steam, the heat rate is assumed to equal the heat rate of facilities that generate only electricity.

SOURCE: Government Advisory Associates, *Resource Recovery Yearbook*, 177 East 87th Street, New York, NY, 1993.

MODEL INPUT: *UPMCF*

DEFINITION: Capacity factor for an LFG plant

SOURCE: Electric Power Research Institute, Technical Assessment Guide. EPRI TR-102276S, Vol. 1: Rev. 7, Palo Alto, CA, June 1993.

MODEL INPUT: *UPOVR*

DEFINITION: Capital cost of an LFG plant

SOURCE: Electric Power Research Institute, Technical Assessment Guide. EPRI TR-102276S, Vol. 1: Rev. 7, Palo Alto, CA, June 1993.

MODEL INPUT: *UPFOM*

DEFINITION: Fixed operation & maintenance (O&M) cost for an LFG plant

Data for calculating operating costs are obtained from the EPRI Technical Assessment Guide (TAG). Data are available for mass burn technology and refuse derived fuel. Information for the mass burn technology is used in the calculations, assuming a 78% capacity factor.

SOURCE: Electric Power Research Institute, Technical Assessment Guide. EPRI TR102276S, Vol. 1: Rev. 7, Palo Alto, CA, June 1993.

MODEL INPUT: *WVCMSEL*

DEFINITION: Variable O&M cost for an LFG plant in EMM region *n* and year *y* adjusted for tipping fees

Data for calculating the operating cost are obtained from the EPRI Technical Assessment Guide (TAG). Data are available for mass burn technology and refuse derived fuel. Information for the mass burn technology is used in the calculations. The variable operating cost is adjusted by subtracting the tipping fee and assigning the operating cost value to the RFM common block variable, WVCMSEL.

SOURCE: Electric Power Research Institute, Technical Assessment Guide. EPRI TR102276S, Vol. 1: Rev. 7, Palo Alto, CA, June 1993.

MODEL INPUT: *WVC*

DEFINITION: Variable O&M cost for an LFG plant

Variable represents the unadjusted (excluding tipping fees) O&M cost for LFG plants.

SOURCE: Electric Power Research Institute, Technical Assessment Guide. EPRI TR102276S, Vol. 1: Rev. 7, Palo Alto, CA, June 1993.

MODEL INPUT: *SR*

DEFINITION: Annual source reduction factor, the amount of annual waste stream reduction achieved - percentage.

SOURCE: EIA, Office of Electricity, Coal, Nuclear, and Renewable Energy Analysis.

MODEL INPUT: a_1

DEFINITION: Regression coefficient representing the GDP dependency of the waste stream

Source: Franklin Associates, "Characterization of Municipal Solid Waste in the United States: 1997 Update," prepared for the U.S. Environmental Protection Agency, Municipal and Industrial Solid Waste Division, Office of Solid Waste, May 1998.

MODEL INPUT: a_2

DEFINITION: Regression coefficient representing the population dependency of the waste stream.

SOURCE: Franklin Associates, "Characterization of Municipal Solid Waste in the United States: 1997 Update," prepared for the U.S. Environmental Protection Agency, Municipal and Industrial Solid Waste Division, Office of Solid Waste, May 1998.

MODEL INPUT: α

DEFINITION: Waste stream adjustment factor - expands the EPA-defined MSW quantity to account for empirical information on other disposed materials.

SOURCES: BioCycle, "The State of Garbage in America," Annual series, (April 1988-April 1997).

Franklin Associates, "Characterization of Municipal Solid Waste in the United States: 1998 Update," prepared for the U.S. Environmental Protection Agency, Municipal and Industrial Solid Waste Division, Office of Solid Waste, May 1998.

Appendix 2-B: Mathematical Description

This Appendix provides the detailed mathematical specification of the LFG Submodule as presented in the RFM Fortran code execution sequence.

The LFG submodule first computes the annual amount of municipal solid waste as a bi-linear relation of the national population and the economic activity as represented by the GDP.

$$WASTE\_STREAM_Y = a_1 \times MC\_GDP92C_y + a_2 \times MC\_N_y$$

where

$WASTE\_STREAM_y$	=	national annual waste stream in year *y*, in millions of tons
y	=	Current projection year
a_1	=	regression coefficient representing the impact of change in GDP
	=	0.02523713 million tons per billion dollars
a_2	=	regression coefficient representing the impact of change in population
	=	0.159544 ton per capita
MC_GDP92C_y	=	GDP (chain weighted) in year *y*, in billions of dollars
MC_N_y	=	national population in year *y*, in millions

The waste stream is then adjusted to capture the efforts to reduce generation of MSW and to reflect definitional change. The relation is expressed as:

$$WASTE\_STREAM_{adj} = WASTE\_STREAM_y \times (1 - (y + 15) \times SR) \times \alpha \times 1000$$

where

$WASTE\_STREAM_{adj}$	=	Adjusted national annual waste stream in year *y*, in millions of tons
y	=	Current projection year
SR	=	source reduction factor[9]
α	=	waste stream adjustment factor - expands the EPA-defined MSW quantity to account for empirical information on other disposed materials. The value is calculated as a simple average of the ratios of the EPA value to the total waste value from a state survey by *BioCycle* magazine.[10]

---

[9] Allaway, David, "Does Source Reduction Work?", *Resource Recycling*, July 1992, pp. 52-61.
[10] "The State of Garbage in America" (repeated annually), *BioCycle*, April/May, 1989-1997.

Source reduction factor

Projections of MSW generation quantities based on the above regression approach must be modified because of structural market changes that are occurring and are likely to occur in future years. Governments and businesses have adopted strategies to lessen the amount of waste generated without reducing economic output. The general term for these strategies is *source reduction*. An example of such a strategy is the local government trend toward unit-based disposal rates, which has brought about a reduction of generated waste where implemented. Source reduction goals can be met through a combination of source reduction and recycling. To the extent that source reduction strategies are successful, they will likely alter the basic relationship between GDP and MSW quantity.

In order to reflect anticipated annual reductions in the quantity of MSW generated on account of source reduction efforts, the quantity projected by the MSW supply equation will be reduced by an exogenously-determined source reduction multiplier. This multiplier, *SR*, will be based in part on legislation passed or proposed to promote source reduction. Currently, EIA uses expert judgment to derive the SR parameter that is used in the MSW supply equation.

Waste stream adjustment factor

As mentioned earlier, the basic regression to develop coefficients uses the EPA definition of MSW. However, this definition omits a notable segment of the waste stream that is likely to be burned or buried. Among omitted materials are tires, construction and demolition debris, and certain industrial materials. An adjustment is computed as a multiplier on the equation to represent the inclusion of these items. The value for it is the average of the incremental differences between the EPA value and one presented in an annual survey by *BioCycle* magazine. The same value applies to all regions. EIA estimates the portion of waste that is non-biogenic and allocates the electricity produced from this waste into a total that remains separate from the renewable total.

Appendix 2-C: Bibliography

BioCycle, "*The State of Garbage in America*," April and May issues, 1989-2003.

Electric Power Research Institute, *Technical Assessment Guide*. EPRI TR-102276S, Vol. 1: Rev. 7, Palo Alto, CA, June 1989.

U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, Vol. 2. Stationary Point and Area Sources*, 4th edition. Supplement D, AP-42, September 1991, p. 2.1-7.

U.S. Environmental Protection Agency, "Municipal Solid Waste in the United States: 1999 Final Report," Municipal and Industrial Solid Waste Division, Office of Solid Waste, May 1999.

Curlee, Randall, T., "*MSW Projection for the EIA 1992 Annual Energy Outlook, Draft Report*," Oak Ridge National Laboratory, prepared for the U.S. Energy Information Administration, August 1991.

Curlee, Randall, T., "Projection of Energy from Combustion of Municipal Solid Waste: 1993, DOE/EIA AEO Update," Oak Ridge National Laboratory, prepared for the U.S. Energy Information Administration, July 1992.

Franklin Associates, "Characterization of Municipal Solid Waste in the United States: 1997 Update," prepared for the U.S. Environmental Protection Agency, Municipal and Industrial Solid Waste Division, Office of Solid Waste, May 1998.

Government Advisory Associates, *Resource Recovery Yearbook*, 177 East 87th Street, New York, NY, 1993.

National Solid Waste Management Association, "The 1992 Municipal Waste Combustion Guide," *Waste Age* 23(11): pp. 99-117, November 1992.

National Solid Waste Management Association, "1990 Landfill Tipping Fee Survey," Washington, DC.

Office of Technology Assessment, *Facing America's Trash: What Next for Municipal Solid Waste?*, Congress of the United States, U.S. Government Printing Office, Washington, DC, October 1989.

Science Applications International Corporation, McLean, VA, "Updated Estimates of Methane Emissions from U.S. Landfills," (McLean, VA, June 1997).

SERI, "The Potential of Renewable Energy," an Interlaboratory White Paper, Solar Energy Research Institute and other laboratories, SERI/TP-260-3674, Golden Colorado, March 1990.

Klass, "*The U.S. Biofuels Industry*," Energy from Biomass and Wastes XIV, " Institute of Gas Technology," Chicago, Il, pg 1-46, 1990.

Waste Age, "*The 1992 Municipal Waste Combustion Guide*," November 1992.

Appendix 2-D: Model Abstract

Model name:
Landfill Gas Submodule

Model acronym:
LFG

Description
The submodule uses the quantity of municipal solid waste produced (derived econometrically) to produce forecasts of the production of electricity from landfill gas. Forecasts are disaggregated by region.

Purpose of the model:
The LFG Submodule provides the NEMS Electricity Market Module with annual regional projections of energy produced from landfill gas. The submodule provides regional forecasts of electric capacity to be decremented from electric utility capacity requirements, as well as capital and operating costs for the calculation of electricity prices.

Most recent model update:
March 2003.

Part of another model?:
The LFG submodule is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

Official model representative:
Chris Namovicz
Renewable Electricity Analysis Team
Office of Electricity, Coal, Nuclear and Renewables Analysis
U.S. Energy Information Administration, EI-341000 Independence Ave., SW
Washington, DC 20585
Phone: (202) 586-7120
e-mail: chris.namovicz@eia.gov

Documentation:
Model Documentation Report, Renewable Fuels Module of the National Energy Modeling System, May 2017.

Archive media and installation manual(s):
Archived as part of the NEMS production runs.

Energy system described:
Energy production from the combustion of landfill gas.

Coverage:

- Geographic: Twenty-two modified EMM regions.
- Time Unit/Frequency; Annual through 2040
- Products: generating capacity
- Economic Sectors: electric utility sector

Modeling features:

- Model Structure: Sequential calculation of forecasted landfill gas to electricity generation, followed by derivation of regional and sector energy shares based on estimates of the percentage of MSW combusted.
- Modeling Technique: Econometric estimation of municipal solid waste generation, coupled with an energy share allocation algorithm for deriving electric generation capacity and energy quantities by sector and region.
- Special Features: Allows for the modeling of regional and national resource recovery efforts.

Non-DOE input sources:

Franklin Associates, data prepared for the U.S. Environmental Protection Agency:

- National annual quantity of municipal solid waste generated
- Current annual percentages of municipal solid waste combusted and landfilled

Government Advisory Associates, *Resource Recovery Yearbook* and Resource Recovery Database:

- Plant-specific electricity generation, Btu energy content of MSW
- Plant locations and energy consuming sectors

Electric Power Research Institute, TAG Technical Assessment Guide:

- Capital cost; fixed and variable operation & maintenance costs
- Plant capacity factor

DOE input sources:

Source reduction factor
Waste stream adjustment factor
Landfill gas-fueled capacity
Projected shares of MSW combusted and landfilled
Heat content of MSW
Current capacities for MSW and landfill gas-fueled units

Independent expert reviews conducted:

None.

Status of evaluation efforts by sponsor:

None.

Appendix 2-E: Data Quality and Estimation Processes

This Appendix discusses the quality of the principal sources of input data used in the LFG Submodule, along with a discussion of user-defined parameters and guidelines used to select them.

A principal driver of the LFG projection is the estimation of the projected waste stream. This is done in a stepwise fashion beginning with EPA data and supplemented with data from *BioCycle*. EPA data are based on in-depth analysis, but are defined narrowly. However, the data have the advantage of a lengthy series. The data were correlated to GDP and population data. Since considerable material outside that definition will be disposed of in combusters and landfills, the EPA value was factored up to a level represented by *BioCycle's* survey data. The weakness of this data is that the individual states reporting use varying definitions of MSW, and the vintage of the data series varies somewhat. The source reduction value is estimated based on readings of MSW literature and although the precise level is based on expert judgment, it is deemed important to include.

The portion of capacity that was projected from the landfilled share of the waste is estimated in the model. There is a somewhat similar stepwise process for deriving energy and hence, capacity for this share. The key is the formulae for computing gas yield from existing and future landfilled MSW over their lifetimes. These have been developed from EPA research reports and are assumed to remain valid throughout the forecast horizon. The conversion of the resulting gas energy to generating capacity is similar to the approach for combusters. A key assumption is the increase in the percent of gas captured from about 13% in 1995 to about 50% by 2010. This is consistent with the goals of an EPA program to reduce methane emissions.

3. Wind Energy Submodule (WES)

Model purpose

The Wind Energy Submodule (WES) contains information on U.S. regional wind energy resources and provides estimates of wind supplies by region and cost category to the Electricity Capacity Planning (ECP) component of the Electricity Market Module (EMM). WES quantifies regional wind supplies by differences in average wind speed. General technology values – such as overnight capital cost, fixed operations and maintenance costs, generation subsidies, construction profiles, and optimism and learning characteristics – are input directly from the ECPDAT file in the EMM. EIA models two technologies for wind: onshore and offshore installations. The fundamental structure of the models for onshore and offshore are very similar. This documentation will focus on the structure of the onshore technology, and will note where the modeling of offshore resources differs.

The RFM data file "rendat" contains the short- and long-term cost adjustment factors. The combination of wind supplies and technology costs yields regional wind technology cost supply information to the EMM.

After determining the projected new capacity builds for a given model year, the EMM provides the WES information on installed wind capacity. WES then subtracts new capacity from the resource supply to determine the remaining wind resources available for future installations.

Relationship of the Wind Energy Submodule to other models

As a submodule of the RFM, WES receives data from and provides its output through the RFM. WES is initiated by a call from the RFM. The RFM then provides input to and receives values from the EMM. The WES calculates values for two variable arrays for each of the onshore and offshore wind technologies modeled, which are then passed to the EMM for further processing. The calculated arrays are (1) yearly available capacity per region, and (2) yearly capacity factors for each wind class, region, and subperiod (i.e., "slice" of the load duration curve). The first array is calculated from the available land (or ocean) area divided into wind classes (average speed "bins"), the expected power generation per area of wind resource, and the annual capacity factor for each wind class. The second array is calculated from hourly capacity factors by month as adjusted for estimated technology learning and surplus wind generation curtailed during hours of the year with high wind output and low demand. All other input data, such as economic life, tax life, construction profile, fixed operation and maintenance costs, the forced outage rate, and other values, are passed directly from ECPDAT to the EMM. The WES generates a wind capacity supply curve with a straightforward (deterministic) calculation from wind turbine performance projections. The uncertainties in the results are related to the technological cost and performance projections, the assumptions about the availability of wind, and other assumptions.

Modeling rationale

Theoretical approach

Wind resources are not a uniform supply for use in electricity generation. Winds vary geographically and temporally (by hour of the day and by season of the year) as well as showing significant variation on factors such as access to transmission lines or site construction/access limitations. The purpose of the Wind Energy Submodule (WES) is to account for effects of these variables on wind supply in estimating the quantities of wind capacity (megawatts or MW) available for new generating capacity in each region in each wind quality category.

All onshore cost parameters assume construction of a 100 MW wind plant (or wind "farm"), notionally consisting of 56 wind turbine generators, each with a rated capacity of 1.79 MW. U.S. wind plants range in size from single-turbine 1 MW (or less) installations to turbine arrays over 700 MW. While wind turbine size has increased in recent years as a way of reducing plant costs, such improvements are implicitly modeled through the learning-by-doing function contained within the EMM, and thus are not explicitly reflected in the assumptions of the WES. Cost parameters for offshore turbines are based on a 400 MW facility, notionally consisting of 80 wind turbines each with a rated capacity of 5 MW. Only one offshore wind facility, Block Island's 30 MW Wind Farm off the shore of Rhode Island, is currently in commercial operation in the U.S. It is assumed that offshore wind developments will require a larger capacity to ensure sufficient economy of scale for installation and maintenance costs. Customer-sited turbines or individual turbines and small turbine clusters connected directly to the distribution grid have significantly different cost, if not performance, characteristics than central-station facilities. Customer-sited wind turbines are modeled in the commercial and residential modules of NEMS.

The submodule begins with estimates of land area for onshore wind and coastal area for offshore wind exhibiting specified ranges of average annual wind speed. It assumes the land-use exclusion scenario described in Appendix 3-E. The WESAREA input file contains resource data validated by the National Renewable Energy Laboratory (NREL) for 33 states (and portions of Texas), with older data from the Pacific Northwest National Laboratory used for states without NREL-validated data.

The wind energy resource potential data set for both onshore and offshore developments excludes lands assumed prohibited by other uses. Onshore wind energy potential includes land resource available in each of four wind quality classes (Classes 3 to 6), while offshore wind energy potential considers coastal areas with Classes 4 to 7 wind quality classes. All wind quality classes are as defined by NREL and measured at a height of 50 meters. The WES uses this data to calculate generating capacity available in each forecast year for each wind quality category, after accounting for current installed capacity. For use in calculating efficiencies and costs, WES also differentiates and projects regional average capacity factors by EMM load periods.

Having estimated available megawatts regional capacity, the EMM uses general cost and performance values in ECPDAT and regional capacity factor values for the EMM load periods to calculate the net present value of the wind technology over its economic life. It then competes wind technology with fossil and other alternatives in the capacity planning process.

U.S. commercial wind installations have existed since the early 1980s. Counts of these preexisting installations are used to adjust estimates of available windy land at the beginning of the NEMS model run. The WES tracks the quantity of windy land remaining by wind class that is available for future development after each run year by calculating the amount of resource required to provide a given amount of wind installed capacity and subtracting that amount from the total resource available. This assumes that the best economic resource (i.e. highest average wind speed and closest proximity to the electric grid) is used first. The amount of resource used is then subtracted from the previous year's available amount to yield the current year's available windy land. The wind resource depletion scheme uses the lowest cost wind resource available in each region first, accounting for wind quality (as represented by wind class) and exogenously determined cost multipliers. The multipliers are established as described in "Revising the Long Term Multipliers in NEMS: Quantifying the Incremental Transmission Costs Due to Wind Power," a 2007 report to EIA from Princeton Energy Resources International, although the particular data used in this estimation was updated in 2010. Distance from existing transmission, which in previous versions of NEMS was accounted for separately, is now included in the exogenous cost multipliers.

Offshore wind

The general modeling approach for offshore wind, and some key assumptions, are adopted from work done by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE). The approach is substantially similar to the onshore model that is described in detail here. EIA has modified or substituted some assumptions based on EIA's expert judgment and differences in EERE and EIA approaches to estimating future technology cost reductions. Resource quality (in terms of average annual wind power density) is generally more favorable offshore, although offshore performance for equivalent wind power classes is assumed to be somewhat reduced by reduced turbine availability (resulting from the more difficult maintenance challenge offshore). That is, Class 6 resources are available both onshore and offshore, but the offshore Class 6 resource has a slightly reduced capacity factor compared to the Class 6 onshore resource[11]. Like onshore resources, offshore resources are assumed to have an upwardly sloping supply curve, in part influenced by the same factors that determine the onshore supply curve (such as distance to load centers, environmental or aesthetic concerns, variable terrain/seabed) but also explicitly by water depth. Cost reductions in the offshore technology result in part from learning reductions in onshore wind technology (which is a fairly mature technology) as well as from cost reductions unique to offshore installations.

Fundamental assumptions

WES wind capacity projections

The EMM requires capacity, performance, and cost data by EMM region. Overall technology cost and performance assumptions, such as capital cost, construction profile, fixed operations and maintenance costs, subsidies (e.g. renewable electricity production tax credit), optimism and learning characteristics, and other assumptions applicable to all regions reside in the ECPDAT file of the EMM and not in the

---

[11] As adopted by the Pacific Nortwest National Laboraory (PNNL) in the Wind Energy Resource Atlas (http://rredc.nrel.gov/wind/pubs/atlas/tables/A-1T.html), and subsequently adopted by the National Renewable Energy Laboratory (NREL) in http://rredc.nrel.gov/wind/pubs/atlas/.

WES. Values that vary by region and contribute to differences in generating costs and performance, along with the steps necessary in calculating overall cost differences for capacity decisions in EMM, are found in the WES. As in the EMM, values are provided for 22 EMM regions excluding Alaska and Hawaii. WES also contains distinct time-of-day and monthly capacity factors for each EMM region. These capacity factors are mapped into nine load periods in the EMM, covering three seasons (winter, summer, and spring/fall) and three time-of-day periods (early morning, morning and evening, and peak).

The WES submodule converts estimates of wind supply in each EMM region to estimates of available capacity by wind quality group in the following manner:

First, from the WESTECH file, WES obtains estimates of windy land and coastal areas (square kilometers) in each EMM region by wind class, all estimated at a rotor hub height of 50 meters:

Table 3-1. Wind class

Average Annual Wind Speed	PNNL/NREL Wind Class
19.6 mph +	7
17.9 mph – 19.6 mph	6
16.8 –17.9 mph	5
15.7 – 16.8 mph	4
14.3 – 15.7 mph	3

The data on land area available for wind plant development have been extracted from data produced in coordination with NREL. The WES input data excludes all environmentally protected lands (such as parks and wilderness areas), all lands with greater than 20% slope, all lands known to be reserved by state or federal government for uses exclusive of wind power development (such as national parks), all urban lands, all wetlands, all airports, areas within 3 kilometers of otherwise excluded lands (except wetlands), 50% of non-ridgecrest forested lands, and lands that do not have sufficient density of windy land to support utility-scale wind development (5 square kilometer of windy land within a 100 square kilometer area).

The development and application of the land exclusion criteria within the data are discussed in Appendix 3-E.

Second, all new technologies, including wind, are assigned an increment to capital cost to account for the cost of maintaining and expanding the transmission network. Because terrain, urbanization, and other factors affect costs, these costs are assigned in the EMM for each electric power region, as follows:

Table 3-2. Transmission costs by region

Region Number	Region	transmission cost per kilowatt (1987$)
1	ERCT	50
2	FRCC	50
3	MROE	50
4	MROW	50
5	NEWE	75
6	NYCW	75
7	NYLI	75
8	NYUP	75
9	RFCE	50
10	RFCM	50
11	RFCW	50
12	SRDA	50
13	SRGW	50
14	SRSE	50
15	SRCE	50
16	SRVC	50
17	SPNO	50
18	SPSO	50
19	AZNM	75
20	CAMX	75
21	NWPP	75
22	RMPA	75

Source: U.S. Energy Information Administration, Office of Energy Analysis, input file ECPDAT.
For regional definitions, see http://www.eia.gov/forecasts/aeo/pdf/f2.pdf.

Third, the WES subroutine CALMWA converts windy land areas (square kilometers) to estimates of wind energy (kilowatthours per square meter) by estimating the number of wind turbines to be placed per unit area [12], and the energy capture of each turbine. EIA assumes an array of turbines spaced 5 rotor-diameters between turbines and 10 rotor-diameters between turbine rows. This corresponds to the 6.5 MW per square kilometer power density factor used to calculate the decrement to windy lands.

---

[12] This refers to the resource area eliminated from the wind resource base. The physical plant (turbine foundation, access roads, and associated power equipment) would occupy less than 5% of this land, and the remainder could still be useful for other activities such as agriculture or grazing.

Historical analysis of wind turbine performance for U.S. installations indicates a trend of improving capacity factors with each additional capacity increment. Detailed analysis of this apparent performance improvement is complicated by the wide variety of site-specific performance factors at each installation, but several factors could, in principal, contribute to the observed trend:

- Improvements in turbine reliability, thus ensuring that the turbines are available for generation when the wind is blowing
- Increases in rotor size and turbine height, which enable turbines to capture more consistent, higher quality winds at higher altitude
- Better micro-siting of turbines within wind farms to maximize resource capture and minimize aerodynamic interactions among turbines

Although the Betz limit[13] constrains the theoretical ultimate efficiency of a wind turbine (that is, the amount of energy captured as a fraction of total wind energy passing through the rotor disc), there is no pre-determined physical limit on the capacity factor of a wind turbine. Because no such limit on capacity factor can be theoretically derived, the RFM allows the user to input a limiting capacity factor for each of the three wind classes modeled based on the user's assessment of the economic trade-offs involved in turbine design and how these trade-offs are likely to be realized under future market conditions.

Typically, learning functions describe a decrease in cost as a function of cumulative units constructed or sold (sometimes in the functional form of a logarithmic decay, with each doubling of units resulting in some fractional decrease in cost). In the case of wind turbine performance, this typical functional form does not describe a process by which capacity factor increases (rather than decreases) toward some limiting level (absolutely limited to 100%, but likely limited to a significantly lower fraction) with increasing cumulative capacity additions.

Learning-induced improvement in wind turbine capacity factor is assumed to asymptotically approach the user-specified capacity factor limit according to

$$C = C_U e^{-b/G}$$

where C is the current capacity factor,
C_U is the ultimate capacity factor for wind Class 6 (CFULT in the WESAREA input file),
b is the decay factor, and
G is the current capacity (as passed to the RFM).

The user can specify the decay factor, b, by indicating an assumed Class 6 wind capacity factor at a specified level of capacity installation. The decay factor is calculated as follows:

$$b = G_I \ln(\frac{C_I}{C_U}),$$

---

[13] See www.windpowerwiki.dk/index.php?title=Betz%27_law for an explanation of the Betz limit.

where G_I is the total installed wind capacity at some initial time *I* (FIXEDX in the WESAREA input file), C_I is the assumed capacity factor for Class 6 wind turbine installations at time *I* (CFATX in the WESAREA input file), and C_U is as above, the ultimate achievable Class 6 capacity factor. C_U must be greater than or equal to C_I.

Because of the wide variation observed in the capacity factor of actual wind plant installations, and the uncertainty over the actual wind class each is constructed in, a reliable "initial conditions" measure of Class 6 capacity factor for any given year/level of installed capacity cannot be constructed. Therefore, the user can specify the initial conditions based on the best available information/analysis.

The RFM directly calculates only the Class 6 capacity factor. Capacity factors for Class 5, 4, and 3 wind resources are scaled to the Class 6 value, based on the ultimate capacity factors specified for each class (CFULT in the WESAREA input file).

The derivation of the capacity factor learning algorithm is detailed in the report "Modeling wind and intermittent generation in the National Energy Modeling System (NEMS)."[14]

Capacity factors for each of the nine ECP load segments (three seasons, each with three time-of-day periods, as detailed in the EMM documentation) are calculated based on the capacity factor of the best available wind class in each region, as adjusted to account for surplus wind production curtailed to balance system demands during periods of high wind output and low demand. The file WESAREA provides a table of the fraction of annual hours and the fraction of total annual wind energy output in each load segment for each region. The time-specific capacity factor is calculated as follows:

$$C_t = C_T \frac{E_t}{H_t},$$

where C_t is the capacity factor for load segment *t*, C_T is the annual average capacity factor, E_t is the fraction of wind energy output for load segment *t*, and H_t is the fraction of annual hours in load segment *t*.

This surplus wind curtailment initially manifests itself when a high penetration of wind capacity produces above-average generation during times of low system demand. Because other units, typically steam units fired by coal or nuclear fuels, may already be committed to generation during baseload hours, unexpected or especially large excess production from wind generators within a self-contained electricity supply region may require system operators to choose between cycling (turning down or off) thermal plants or curtailing wind plants (that is, shutting down some significant portion of capacity, despite available wind resource).

---

[14] Namovicz, C. "Modeling wind and intermittent generation in the National Energy Modeling System (NEMS)." Proceedings of WindPower 2003, Austin TX. American Wind Energy Association. May 2003.

To account for this curtailed wind energy, it is assumed that only nuclear and coal-steam plants are limited in ability to cycle to accommodate excess wind during low load. Furthermore, it is assumed that these plants may be cycled down to a user-specified "turn-down" ratio, currently 3:1 of nameplate capacity for coal and 2:1 for nuclear, before system operators would curtail wind production to avoid further cycling or unit shutdown. If any other units (gas-fired simple cycle or combined cycle turbines, for example) operate during affected load periods, it is assumed that they may be fully cycled (including shut-down) to accommodate excessive wind output without significant economic, safety, or other technical cost.

On average, wind units will contribute energy to meet segment-specific load based on the wind capacity factor for the given region and load segment. In the real world, to the extent that it does not create difficulties for other committed units, wind would be allowed to contribute to the extent the wind was blowing at any given time (that is, with near-zero running cost, it would always be the low-bid in the dispatch pool). However, there is a probability that local or regional high winds will increase the wind energy contribution at any given time. This probability, of course, increases with increasing wind capacity penetration in the regional power pool. There is also a probability that the wind will contribute less-than-average energy to the load segment, but other mechanisms within NEMS account for this effect (see the description of the capacity credit algorithm in Appendix 1-A of this report).

To determine the probability that the wind output will be in excess of operational limits, the user must specify a normalized standard deviation of output from a typical regional wind plant. Analyses of typical wind regimes and wind turbine power curves indicate that a reasonable approximation for this parameter is 38% of the average power output of a 100 MW wind farm (about 38 MW). In scaling this distribution to represent a large amount of capacity installed over a large region, the model must account for the geographical diversity of the wind resource. That is, the wind will be blowing at various speeds over a wide area, so the output of each turbine (or plant) will not be perfectly correlated with the output of the other turbines (plants) in the system. For partially correlated wind units, the total standard deviation of the system could be approximated by

$$S_T = \sqrt{(N + (N^2 - N) \times R) \times S^2} \ ,$$

where R is the specified correlation coefficient of the output at each site, assuming constant correlation among all sites as specified in the WESAREA input file and N and S are the number of plants and standard deviation of output (see Appendix 1-A of this document for further derivation of this approximation and of the correlation factors used).

Current default correlations are as follows:

Table 3-3. Regional wind correlation

Region Number	Region	Correlation
1	ERCT	0.89
2	FRCC	N/A
3	MROE	0.84
4	MROW	0.86
5	NEWE	0.74
6	NYCW	N/A
7	NYLI	N/A
8	NYUP	0.69
9	RFCE	0.79
10	RFCM	0.77
11	RFCW	0.73
12	SRDA	0.96
13	SRGW	0.87
14	SRSE	N/A
15	SRCE	0.8
16	SRVC	0.55
17	SPNO	0.77
18	SPSO	0.89
19	AZNM	0.87
20	CAMX	0.77
21	NWPP	0.87
22	RMPA	0.89

For regional definitions, see
http://www.eia.gov/forecasts/aeo/pdf/f2.pdf.

The standard deviation of wind output from installed capacity can be used to estimate the standard deviation of a Gaussian distribution of wind power output for the region, where the mean equals the installed capacity times the annual average capacity factor. To determine the amount of wind that needs to be curtailed, the model next determines the point at which to evaluate the normal distribution: the critical wind output level where curtailment must occur to avoid the unplanned shut-down or excessive cycling of coal or nuclear plants. This critical point is as follows:

$$W_{Crit} = L_{g,t} - \left[\left(D_{coal} \times O_{coal} \times C_{coal}\right) + \left(D_{nuclear} \times O_{nuclear} \times C_{nuclear}\right)\right]$$

where W_{Crit} is the critical limit on wind output, $L_{g,t}$ is load for Region g and Load time-slice t. D is the minimum operating fraction of nameplate capacity (inverse of turn-down ratio) for the specified plant type, O is the total (planned and forced) outage rate for the specified technology, and C is the regional installed capacity of each technology.

With the wind output standard deviation for installed capacity and the critical limit, the necessary parameters are available to determine the probability of wind output greater than W_{Crit}. This is done by evaluating:

$$P(W_{Crit}) = \frac{1}{\sqrt{2\pi}S_T} e^{-\frac{(W_{Crit} - W_{Ave})^2}{2S_T^2}},$$

where $P(W_{Crit})$ is the probability of wind output in excess of W_{Crit} and where W_{Ave} is the average output of regional installed wind capacity for the current slice of the regional load duration curve (time-slice-specific capacity factor times installed nameplate capacity or LDC).

If no wind curtailment is assumed, total wind energy output in the current slice of the LDC t would be:
$$E_t = F_t * W_{nameplate} * H_t,$$

where $W_{nameplate}$ is the nameplate installed capacity for the region, H_t is the total number of hours in the current slice of the LDC t, and F_t is the capacity factor for wind during LDC slice t.

The energy curtailed is

$$E_{t,curtail} = P(W_{Crit}) * W_{nameplate} * H_t.$$

The adjusted total energy produced during slice t is the difference between the total wind energy output without curtailment and the curtailed output ($E_{t,adjusted} = E_t - E_{t,curtail}$), so the adjusted capacity factor for wind during LDC slice t is:

$$F_{t,adjusted} = \frac{E_{t,adjusted}}{W_{nameplate} * H_t}$$

After adjusting the capacity factors for each segment, the submodule recalculates the annual average capacity factor to be passed to the EMM. However, in the next model iteration, the learning for capacity factor is applied to the baseline (non-adjusted) capacity factor value, and the curtailment adjustments are re-calculated.

For the reference case, the parameters for wind turbine capacity factor learning are as follows:

Variable	Wind class				
	Class 7	Class 6	Class 5	Class 4	Class 3
Ultimate achievable capacity factor, *CFULT*					
Onshore	-	55%	50%	45%	40%
Offshore	58%	52%	47%	41%	-
Known capacity factor, *CFATX*					
Onshore (based on Class 6 capacity factor in 2015)			48% (all classes)		

Variable	Wind class				
	Class 7	Class 6	Class 5	Class 4	Class 3
Offshore (based on Class 7 capacity factor)			50% (all classes)		
Total installed wind capacity at which known capacity applies, *FIXEDX*					
Onshore and offshore			75 GW (all classes)		
Power density of a turbine (5 × 10 rotor-diameter spacing), *PWRDEN*					
Onshore			6.5 MW (all classes)		
Offshore*			5 MW (all classes)		

*Reflects the decreased directionality of the offshore wind resource compared to the typical inland resource.

After new wind generating capacity is selected in the EMM, WES decrements projected wind supplies to estimate remaining wind resources.

Cost adjustment factors

Capital costs for wind technologies increase as a function of either short-term or resource constraint cost adjustment factors. The short-term factor in the model accounts for short-term bottlenecks in production, siting, and construction costs and is reflected in additional capital costs incurred in a specific year for all new units of U.S. wind capacity beyond a defined threshold. This adjustment is applied in the ECP and is documented in the EMM documentation. The resource constraint cost adjustment factor (also referred to as the long-term cost multiplier) is discussed below.

Rationale

Capital costs for generating technologies using wind resources are assumed to increase as a function of exhaustion of most favorable resources. In general, capital costs are assumed to increase because of any or all of three broad conditions: (1) necessity of using less favorable natural resources, (2) increasing costs of upgrading existing distribution and transmission networks - separate from costs of building an interconnection, and (3) increasing costs in meeting environmental concerns.

As a result, each EMM region's total wind resources are parceled among five broad ranges, including an initial resource share incurring no capital cost penalty, a second share for which capital costs are assumed to increase 10%, a third share imposing increases of 25%, a fourth at 50%, and a final share (all remaining resources) for which capital costs increase 100% over initial cost. Resource proportions vary by technology and region.

Methodology

For wind, the resource-related cost adjustment factors account for the additional capital costs that are not reflected in the RFM cost characterizations. For inland wind resources, EIA estimates these cost adjustment factors based on work performed for EIA by Princeton Energy Resources, Inc. (PERI) and NREL[15] This work specifically estimates the additional investment in transmission facilities needed to

---

[15] McVeigh, Jim. Revising the Long Term Multipliers in NEMS: Quantifying the Incremental Transmission Costs Due to Wind Power. Report to EIA, Princeton Energy Resources International, June 2007. Subsequent updates based on work performed by the National Renewable Energy Laboratory (NREL) for EIA in 2011.

access wind resources and deliver the energy to load centers. Other factors, such as resource degradation or higher-value land uses are implicitly included in the cost adjustment factors as well.

The cost-adjustment factors are applied on a regional basis as a function of the fraction of total resource for each relevant technology used in each of the 22 EMM regions.   For each region/technology combination, the input file RENDAT allows the user to specify the start-point resource fraction and multiplier for each of the five steps. For example, if the cost of using wind resources in Region 1 is assumed to increase by 10% after 5% of the resource base has been used, then 1.1 would be entered for the cost multiplier and 0.05 would be entered for the current resource utilization fraction for the second step of the Region 1 table in RENDAT.

The resource cost multiplier is determined for each wind class based on the fraction of available windy land already used in that class. If desired, the capital cost for wind plant installation in each wind class for each year can be differentiated using a fixed ratio (using the "Multiplier or Cost by Wind Class" line in the WESAREA file). The default ratio is 1.0 for all years and wind classes. Based on the 9-step supply curve for each region in each year, the levelized cost of each combination of the class-specific capacity factor and class-specific resource multiplier is calculated using parameters passed from the Electricity Market Module for fixed charge factor and wind cost learning. The supply steps are then ordered by cost. The supply step with the lowest levelized cost is used to establish the wind class and resource multiplier for the capacity available for that region. If the step with the lowest levelized cost does not have the minimum fraction of the previous year's regional capacity increment available (called Percent Tolerance in the WESAREA file, and set as 1.0 for the current default), the lowest cost step where the cumulative available capacity meets this tolerance level is used instead. If there is insufficient resource available in any step to meet the tolerance, then the wind class, transmission adder, and resource multiplier are taken from the highest-cost step. The total capacity available for new builds in each region, each year is the lesser of the actual resource available and the maximum national wind capacity limit determined by the previous year's national capacity installations.

The short-term elasticity is determined in the EMM based on the past growth rate of wind capacity. This methodology is described in the EMM documentation.

Key computations and equations

For the first model year, the subroutine WINDIN3 is called. This reads in the data from the WESAREA file. Where necessary, data entered in 5-year increments is linearly interpolated to produce annual values.

The subroutine WINDMISC3 is then called. This routine calculates cumulative builds and remaining windy land area in each region, wind class, and transmission buffer. The routine then determines the "best" wind class and buffer zone in each region based on currently available capacity factors for that wind class and region, and current technology costs and financial parameters passed from the EMM. The routine then calculates available capacity, capacity factors by time slice, and determines the T&D costs. Finally, the maximum capacity available and the amount of capacity currently used are calculated.

Subroutine WINDREPT3 writes the key parameters and calculation results to the output file WINDDBG.

Alternative approaches

NREL has developed the Renewable Energy Deployment System model (ReEDS), which uses a similar capacity planning approach as NEMS in determining expansion of grid resources. Although ReEDS lacks the robust, inter-sectoral feedbacks of NEMS, it does contain significantly more detail in representing the geographic and operational limitations of wind generation. Specifically, ReEDS utilizes a geographic information system to estimate the need for and cost of transmission capacity investment to support the development of wind resources that may be remote from load. This also allows a somewhat higher resolution consideration of intermittency impacts on capacity credit and the need for operational reserves.

Computational run-time constraints preclude the incorporation of the full level of ReEDS detail into the NEMS wind module. To a large extent, NEMS and ReEDS have similar treatment of intermittency impacts, albeit at differing levels of detail. NEMS incorporates estimates of transmission grid expansion costs derived directly from the same geographical information system used as an input to ReEDS.[16]

Wind Energy Submodule structure

Submodule flow diagram
A flow diagram showing the main computational steps and relationships of the Wind Energy Submodule is shown in Figure 2.
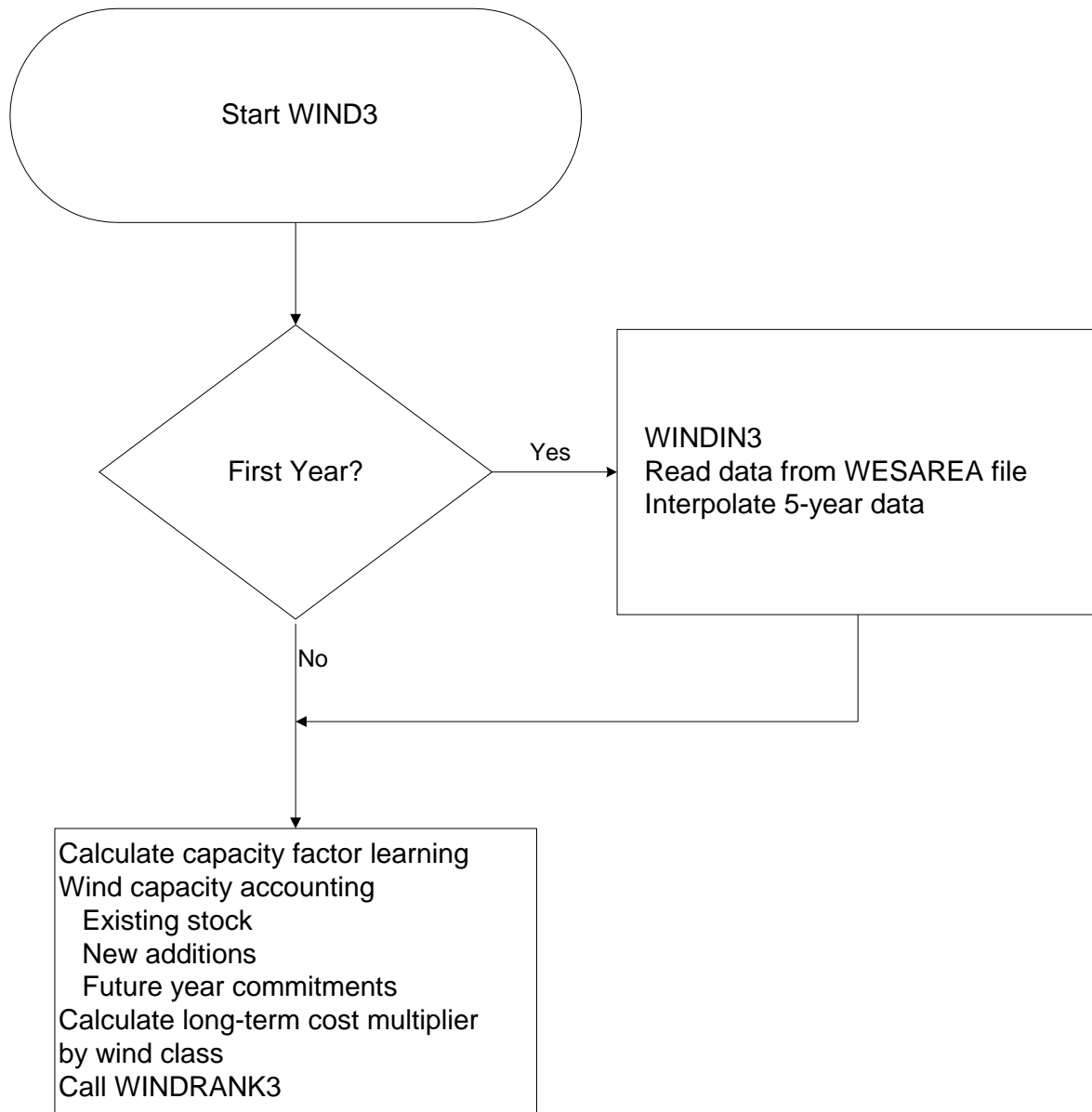
Key computations and equations
Some of the input data are at 5-year intervals. For the first year, a linear interpolation on these data is performed to calculate yearly values.

For all years after the first year, subroutine WINDMISC3 is called to calculate the land area remaining for wind energy development, based on the previous wind capacity build decision by the EMM. The previous build decision is passed as a capacity unit (MW) which needs to be converted into a land area required for the development of wind site of that size. The conversion method considers the wind class of the available land area that is being offered for wind development. The entire U.S. wind energy supply is subdivided into 22 EMM regions, and four wind classes.

Subroutine WINDMISC3 calculates subperiod (season, time of day) regional capacity factors. For each year, the subroutine calculates the remaining available wind generating capacity for each region. Finally, it assigns transmission and distribution cost adders for the remaining capacity in each distance zone.

---

[16] As of AEO 2011. Subsequent independent updating of either model may result in divergence of the two sets of assumptions.

Figure 2. Wind energy submodule flowchart

```
        ┌──────────────────────────┐
       (        Start WIND3         )
        └──────────────────────────┘
                     │
                     ▼
              ╱╲
            ╱    ╲
          ╱        ╲        Yes    ┌─────────────────────────────┐
        ╱  First Year? ╲──────────▶│ WINDIN3                     │
          ╲          ╱             │ Read data from WESAREA file │
            ╲      ╱               │ Interpolate 5-year data     │
              ╲  ╱                 └─────────────────────────────┘
              No │                              │
                 ▼                              │
                 ◀──────────────────────────────┘
                 │
                 ▼
  ┌──────────────────────────────────────┐
  │ Calculate capacity factor learning    │
  │ Wind capacity accounting              │
  │    Existing stock                     │
  │    New additions                      │
  │    Future year commitments            │
  │ Calculate long-term cost multiplier   │
  │ by wind class                         │
  │ Call WINDRANK3                        │
  └──────────────────────────────────────┘
```

Appendix 3-A: Inventory of Variables, Data, and Parameters

This Appendix describes the variables, parameter estimates, and data inputs associated with the Wind Energy Submodule. Table 3A-1 provides a tabular listing of model variables and parameters. The table contains columns with information on item definitions, modeling dimensions, data sources, and measurement units. Because of the parallel data structures for onshore and offshore wind resources, there are many functionally equivalent variables listed together. A prefix of "F" denotes the variable for offshore.

The remainder of Appendix 3-A consists of detailed descriptions of data inputs and variables, including discussions on supporting data assumptions and transformations.

Table 3A-1. NEMS wind energy submodule inputs and outputs

Model Variable	Definition and Dimensions	Source	Units
INPUT DATA			
CFANN, FCFNN	User specified annual capacity factor by wind class and year	No default value specified	Unitless
CFATX, FCFATX	Improvement capacity factor at initial capacity	EIA, expert judgment	Unitless
CFULT, FCFULT	Ultimate capacity factor by class	EIA, expert judgment	Unitless
CTURNDOWN, FCTURNDOWN	Minimum fraction of coal-fired capacity that must be kept running by region	EIA, expert judgment	Unitless
FIXEDX, FFIXEDX	Initial installed capacity used to determine slope of capacity factor	EIA, expert judgment	GW
ICCMETH	Method used to assign class-specific capital cost multipliers	N/A	Boolean
ICCMULT	Class-specific capital cost multipliers	No default value specified	Unitless
INTREGCRL, FINTREGCRL	Regional correlation factor for intermittent resources	EIA, expert judgment	Unitless
INTSTDDV, FINTSTDDV	Normalized standard deviation of hourly output for intermittent resource facilities	EIA, expert judgment	Unitless
NTURNDOWN, FNTURNDOWN	Minimum fraction of nuclear capacity that must be kept running by region	EIA, expert judgment	Unitless
OVERRIDECF	Switch to use user-specified capacity factors instead of capacity factor learning	N/A	Boolean
PercentTOL	Minimum wind resource required to be available to be selected as the typical wind resource for a given year	EIA, expert judgment	Unitless
PWRDEN, FPWRDEN	Power density of a 10x5 diameter turbine array	EIA, expert judgment	MW/km^2
SLICE, FSLICE	Hour fraction for subperiod *l* in EMM region *n*	NREL	Unitless

Table 3A-1. NEMS wind energy submodule inputs and outputs (cont.)

Model Variable	Definition and Dimensions	Source	Units
STAREA, FSTAREA	Land area available for wind plant development in EMM region *n* and wind class *w*	NREL	km^2
SUBPER, FSUBPER	Energy fraction for subperiod *l* in EMM region *n*	NREL	Unitless
UADDWNT, UADDWFT	Grid-connected onshore (UADDWNT) and offshore (UADDWFT) wind electric capacity additions in EMM region *n* in on-line year *y*	EMM output variable in UECPOUT COMMON block	MW
UPCLYR*	Construction lead time	EIA expert judgment	Years
UPCPRO	Fraction of construction completed in each year of construction	EIA expert judgment	Unitless
UPFOM*	Fixed O&M cost	EIA, 2016 (onshore) and 2013 (offshore)	$/kW
UPIRGSUB	Policy incentives for EMM region *n* in year *y*	Energy Policy Act of 1992 as amended	Mills/kWh
UPOVR*	Installed capital cost of wind generation.	EIA, 2016 (onshore) and 2013 (offshore)	$/kW
UPVOM*	Variable O&M cost	EIA. 2016 (onshore) and 2013 (offshore)	Mills/kWh
WNTDBFCS	Additional T&D cost for wind technology in EMM region *n* and buffer zone *b*	Not used in default	$/kW
CALCULATED VARIABLES			
WCAWIEL	Available onshore capacity in EMM region *n* in year *y*	RFM output variable in WRENEW COMMON block	MW
WCAWFEL	Available offshore capacity in region onshore in year *y*.	RFM output variable in WRENEW COMMON block	MW
WSFWIEL	Onshore capacity factor for EMM region *n* in year *y*, wind class *w*, and subperiod *l*	RFM output variable in WRENEW COMMON block	Unitless
WSFUFLL	Offshore capacity factor	RFM output variable in WRENEW COMMON block	Unitless
WWNTD	Additional T&D cost for onshore wind technology in EMM region *n* and year *y*	RFM output variable in WRENEW COMMON block	$/kW
WSFTD	Additional T&D cost for offshore wind	RFM output variable in WRENEW COMMON block	$/kW

*Assigned in EMM input file ECPDAT.
**Intermediate values, linearly interpolated from the source variable.

MODEL INPUT: *CFANN, FCFANN*

DEFINITION: Contains overwrite values for annual capacity factor (in 5-year increments) for wind classes 3 to 6, if preferred over having "learning" on capacity factor.

SOURCE: No default input defined

MODEL INPUT: *CFATX, FCFATX*

DEFINITION: Capacity factor for Class 6 (onshore) or Class 7 (offshore) wind sites used to initialize the capacity factor learning function (Unitless)

Historical analysis of wind capacity factors is complicated by the general inability to correlate individual sites with specific, independently determined wind class data. Even if able to locate a turbine on a low-resolution wind resource map, such as is used in NEMS, "micro-siting" issues within a wind farm can have significant effects on turbine performance. This variable is primarily intended to give a reasonable starting point for the calculation of future improvements to wind turbine performance, and not necessarily to reflect absolute knowledge about the idealized state of wind turbine performance at a point in the historical record.

SOURCE: Form EIA-923, EIA expert judgment.

MODEL INPUT: *CFULT, FCFULT*

DEFINITION: Ultimate achievable annual wind capacity factor by class (unitless).

Current wind turbine performance parameters are based on several factors. Discussions with experts from the DOE Wind Power Program and their consultants provided a general indication of recent trends and areas of expected performance increases. Analysis of wind power curves developed for the EPRI/DOE Wind Turbine Verification Program (TVP) provided a firm quantitative characterization of state-of-the-art turbine technology. Finally, analysis of historical trends provided a cross-check to these other sources. Over time, the trade-offs in the economics of increasing rotor size and tower height are expected to balance out. Improvements are assumed to occur as a result of experience in the design and construction of wind turbines.

SOURCES: EIA expert judgment based on data in Form EIA-923.

MODEL INPUT: *CTURNDOWN, FCTURNDOWN*

DEFINITION: Maximum turndown limit for coal-fired capacity in region. Expressed as the minimum fraction of capacity that must be kept running.

SOURCE: EIA expert judgment following examination of PowerWorld transmission reliability data and conversations with system operators.

MODEL INPUT: *FIXEDX, FFIXEDX*

DEFINITION: Installed capacity base at which variable CFATX is assumed (GW).

Historical analysis of wind capacity factors is complicated by the general inability to correlate individual sites with specific, independently determined wind class data. Even if a turbine can be located on a low-resolution wind resource map, such as is used in NEMS, "micro-siting" issues within a wind farm can have significant effects on turbine performance. This variable is primarily intended to give reasonable starting point for the calculation of future improvements to wind turbine performance, and not necessarily to reflect absolute knowledge about the idealized state of wind turbine performance at a point in historical record.

SOURCES: EIA expert judgment based on Form EIA-860 data.

MODEL INPUT: *ICCMETH*

DEFINITION: Method for determining incremental capital cost for wind by wind class. Cost multipliers are used with ICCMETH setting to 1, while actual capital costs are used with ICCMETH setting to 2.

SOURCE: Not used by default

MODEL INPUT: *ICCMULT*

DEFINITION: Capital cost factors for forcing capital cost for wind and/or differentiating capital cost by wind class.

Allows for overwrite of capital cost decline factors (due to learning), as calculated by the EMM. The factors account for capital cost declines that can be differentiated by wind class to simulate separate technology/cost structures potentially used in each class.

SOURCE: No default input defined

MODEL INPUT: *NTURNDOWN, FNTURNDOWN*

DEFINITION: Maximum turndown limit for nuclear capacity in region. Expressed as the minimum fraction of capacity that must be kept running.

SOURCE: EIA expert judgment following examination of PowerWorld transmission reliability data and conversations with system operators.

MODEL INPUT: *INTSTDDV, FINTSTDDV*

DEFINITION: Standard deviation of hourly wind plant output within a region.

Default setting of 38% of nameplate capacity is based on EIA simulation of a generic, 1 MW turbine, assuming a Rayleigh distribution of wind resource in a Class 5 area. The standard deviation is assumed to scale to a 100 MW size, which assumes perfect correlation among turbines on an hourly basis within a 100 MW wind farm.

SOURCE: Internal EIA calculation based on simulated performance of a state-of-the-art wind turbine. Analysis of wind power curves developed for the EPRI/DOE Wind Turbine Verification Program (TVP) provided a firm quantitative characterization of state-of-the-art turbine technology.

MODEL INPUT: *INTREGCRL, FINTREGCRL*

DEFINITION: Correlation coefficient of hourly wind output for wind turbines within a region (that is, the average correlation between the output of two turbines within the region). Appendix 1-A of this document contains further derivation of this approximation and of the correlation coefficients used as default values.

SOURCE: EIA expert judgment. See Appendix 1-A.

MODEL INPUT: *OVERRIDECF*

DEFINITION: Switch to overwrite capacity factor learning with user specified capacity factors.

SOURCE: Not used by default

MODEL INPUT: *PercentTOL*

DEFINITION: Minimum wind resource that must be available within a region, wind class, and transmission buffer in order for the region and wind class to be selected as the typical wind resource for a given year. Expressed as a fraction of prior years' regional wind capacity installations.

SOURCE: EIA expert judgment.

MODEL INPUT: *PWRDEN, FPWRDEN*

DEFINITION: Specific power density of an average wind plant (MW per square kilometer)

Primarily used within the WES to convert projected measure of available area of windy land to available MW of wind resource, and to decrement the available land area based on model builds. Although power efficiency varies somewhat from turbine model to turbine model, this factor is mostly a function of inter-turbine spacing within the turbine array. Some U.S. installations are placed on ridgelines and may have a linear arrangement with relatively tight lateral turbine spacing. However, the factor used here must consider more extensive exploitation of wind resources where the turbines would be placed in more rectangular arrays. The current assumption of 6.5 MW per square kilometer for onshore wind is consistent with spacing estimates from the Pacific Northwest Laboratory (PNL) assessment of windy land used to provide the WES wind resource and the performance estimates from U.S. DOE and EPRI.

SOURCES: EIA expert judgment

U.S. Department of Energy and Electric Power Research Institute. Renewable Energy Technology Characterizations. http://www1.eere.energy.gov/ba/pba/tech_characterizations.html?m=1&

Elliott, D.L. et al. "An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States." August 1991. Pacific Northwest Laboratory. PNL-7789.

MODEL INPUT: *SLICE, FSLICE*

DEFINITION: Hour fraction for subperiod *l* in EMM region *n* (Unitless).

Data for 20 subperiods of the year are provided. The EMM maps the data for these 20 subperiods into nine subperiods used in the EMM and other NEMS modules. SLICE uses established NEMS subperiod definitions, daily and seasonal wind resource data, and a synthetic wind turbine power curve to estimate the fraction of the annual wind energy production that falls within the various subperiods.

SOURCE: National Renewable Energy Laboratory, work performed for EIA.

MODEL INPUT: *STAREA, FSTAREA*

DEFINITION: Land area available for wind plant development in EMM region n and wind class w (sq. km).

SOURCE: National Renewable Energy Laboratory, work performed for EIA.

MODEL INPUT: SUBPER, FSUBPER

DEFINITION: Wind energy fraction for subperiod l in EMM region n (unitless)

SOURCES: National Renewable Energy Laboratory, work performed for EIA.

MODEL INPUT: *UADDWNT, UADDWFT*

DEFINITION: Total grid-connected wind electric capacity additions in EMM region n in on-line year y (MW).

SOURCE: EMM output variable in UECPOUT COMMON block.

MODEL INPUT: *UPCLYR*

DEFINITION: Construction lead-time (Years).

The construction period for a wind generating station is currently set at 3 years.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources.

MODEL INPUT: *UPCPRO*

DEFINITION: Fraction of construction completed in each year of construction (unitless).

The construction period for a new wind generating station is currently set at 3 years with most capital costs allocated in the annual proportion of 5% in the first year, 10% in the second year, and 85% in the final year.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources.

MODEL INPUT: *UPFOM*

DEFINITION: Fixed O&M costs ($/kW).

SOURCE: Onshore: U.S. Energy Information Administration, *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, November 2016. Offshore: U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, April 2013.

MODEL INPUT: *UPOVR*

DEFINITION: Installed capital cost of wind generation ($/kW) in year *y*.

SOURCE: Onshore: U.S. Energy Information Administration, *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, November 2016. Offshore: U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, April 2013.

MODEL INPUT: *UPVOM*

DEFINITION: Variable O&M costs for EMM region n in year *y* at 5-year intervals (mills/kWh).The variable O&M costs are currently set at zero.

SOURCE: Onshore: U.S. Energy Information Administration, *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, November 2016. Offshore: U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, April 2013.

MODEL INPUT: *WNTDBFCS*

DEFINITION: Additional T&D cost for wind development averaged for sites in buffer zone b and EMM region n ($/kW). Not used in the current default version of NEMS. This factor is now expressly incorporated into the long-term cost adjustment factor.

SOURCES: Science Applications International Corporation, "Geographic Information System Analysis," Report for EIA, Office of Integrated Analysis and Forecasting. May, 1995.

U.S. Energy Information Administration, Washington, D.C., September 1994. "Electric Trade in the United States 1992." Table 42: Transmission Lines Added by Investor-Owned Utilities, 1992. DOE/EIA 0531 (92).

Bonneville Power Administration. "Transmission Line Estimating Data." Internal Memorandum. BPA F 1325.01.e, December 3, 1993.

Appendix 3-B: Mathematical Description

This Appendix provides the detailed mathematical specification of the Wind Energy Submodule as presented in the RFM FORTRAN code execution sequence. Subscript definitions are also as they appear in the FORTRAN code.

Two variables are calculated in the WES for each of the onshore and offshore wind technologies modeled. The first array is calculated from the available land (or ocean) area divided into wind classes (average speed "bins"), the expected power generation per area of wind resource, and the annual capacity factor for each wind class. The second array is calculated from hourly capacity factors by month as adjusted for estimated technology learning and surplus wind generation curtailed during hours of the year with high wind output and low demand.

Equation 3B-1 calculates the land area (in sq. km) needed to supply the wind generating capacity called for by the EMM for each EMM region and current year:

$$LDUSED_{n,y} = \frac{UADDWNT_{n,y+lead} \times CF_{y,w} \times 8760 \times \alpha_{sp}}{AREA_{y,w} \times \pi/4}$$

Eq. 3B-1

where

$LDUSED_{n,y}$ = Land area used to supply EMM-called-for wind generating capacity in EMM region n in decision year y, in square kilometer,

$UADDWNT_{n,y+lead}$ = Grid-connected wind electric capacity additions in EMM region n decision year $y+LEAD$ in MW, where

$LEAD$ = Construction lead time, in years (decision year + lead time = on-line year),

$CF_{y,w}$ = Annual capacity factor for wind class w in year y,

8760 = The number of hours in a year,

$AREA_{y,w}$ = Energy per unit swept rotor area for wind class w in decision year y, in kilowatthour per square meter,

π = 3.141593,

α_{sp} = Scalar derived from 5 by 10 rotor-diameter grid spacing of wind generator (see Page 38) and is equal to 50.

Equation 3B-2 subtracts the land area needed to supply the wind generating capacity called for by the EMM from the available land area.

$$LDAREA_{n,y,wc,bc} = LDAREA_{n,y-1,wc,bc} - LDUSED_{n,y}$$

Eq. 3B-2

where

$LDAREA_{n,y,w,bc}$ = land area available for wind development in EMM region *n,* in year *y,* in currently offered wind class *w* and buffer zone *bc,* in square kilometers.

Equation 3B-4 computes the total swept area by turbines for a particular wind class, EMM region and year:

$$SWAREA_{n,y,wc} = \frac{\frac{\pi}{4} * LDAREA_{n,y,wc,bc} * 10^6}{\alpha_{sp}}$$ Eq. 3B-4

where

$SWAREA_{n,y,wc}$ = Swept rotor area available for currently offered wind class *wc* in EMM region *n* in year *y,* in square meters,

$LDAREA_{n,y,w,bc}$ = land area available for wind development in EMM region *n,* in year *y,* in currently offered wind class *w* and buffer zone *bc,* in square kilometers,

α_{sp} = Scalar derived from 5 by 10 rotor-diameter grid spacing of wind generator (α_{sp} = 50).

Equation 3B-5 computes the available wind electric generation capacity (megawatts) in the best wind class and best access to transmission:

$$WCAWIEL_{n,y,w} = \frac{AREA_{y,wc} \times SWAREA_{n,y,wc}}{CF_{y,wc} \times 10^3 \times 8760}$$ Eq. 3B-5

where

$WCAWIEL_{n,y}$ = Available capacity in EMM region *n* in year *y,* MW.

Subroutine WNDECR decrements the projected wind resources that are subdivided by wind classes and buffer zones according to an estimate of the least-cost combination of wind class and buffer zone. As wind resources in a given region are utilized, the model estimates the cost of the remaining resources based on capacity factor (a function of wind class) and any applicable adjustments to capital cost (long-term cost multipliers or, if used, buffer zones) and re-ranks the estimates of available resources to provide to the EMM.

Equation 3B-6 assigns the wind-specific T&D cost associated with wind resources of the buffer zone currently being offered

$$WWNTD_{n,y} = WNTDBFCS_{n,bc}$$

where

$WWNTD_{n,y}$ = Wind specific T&D cost in EMM region *n* in year *y*, in dollars per kilowatt ($/kW),

$WNTDBFCS_{n,bc}$ = Wind specific T&D cost in EMM region *n* in currently offered buffer zone *bc,* ($/kW).

The capacity factors for wind must be adjusted to account for the probability of wind curtailment with increasing wind penetration. Equation 3B-7 computes the capacity factor in a particular load segment as adjusted for estimated learning and wind curtailment.

$$WSFWIEL\_CF_{n,y,t} = \frac{FullWn_{n,y,t} - ExcessWn_{n,y,t}}{Instwind_{n,y}} \qquad \text{Eq. 3B-7}$$

where $WSFWIEL\_CF_{n,y,t}$ = Adjusted capacity factor in EMM region *n* in year *y* during load segment *t*;

$FullWn_{n,y,t}$ = Total wind energy output in EMM region *n* in year *y* during load segment *t* without curtailment;

$ExcessWn_{n,y,t}$ = Wind energy curtailed in EMM region *n* in year *y* during load segment *t*; and

$Instwind_{n,y}$ = Installed wind capacity in EMM region *n* in year *y*.

Appendix 3-C: Bibliography

Bonneville Power Administration, "Transmission Line Estimating Data." Internal Memorandum. BPA F 1325.01.e, December 3, 1993.

Cohen, J.M., Schweizer, T.C., Hock, S.M., and Cadogan, J.B., "A Methodology for Computing Wind Turbine Cost of Electricity Using Utility Economic Assumptions," Proceedings of Windpower '89, American Wind Energy Association, September 1989.

Elliott, D.L., et al., "Wind Energy Resource Atlas of the United States," (1 volume), Report DOE/CH 10093 4, October 1986.

Electric Power Research Institute, *Technical Assessment Guide (TAGJ)*, 1993.

U.S. Energy Information Administration, Washington, D.C., September 1994. "Electric Trade in the United States 1992." Table 42: Transmission Lines Added by Investor-Owned Utilities, 1992. DOE/EIA 0531 (92).

U.S. Energy Information Administration, Washington, D.C., Form EIA-860, Annual Electric Generator Report, 2012.

U.S. Energy Information Administration, "Component Design Report for Solar and Wind Submodules Renewable Fuels Module National Energy Modeling System," Draft, April 23, 1993.

U.S. Energy Information Administration, *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, November 2016.

U.S. Energy Information Administration, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants," April 2013.

Hock, S.M., Thresher, R.W., and Cohen, J.M.; "Performance and Cost Projections for Advanced Wind Turbines," *Proceedings of ASME Winter Annual Meeting*, Dallas, TX, November 1990.

Princeton Economic Research, Incorporated, *Data Development Report for Wind Electric Submodule Renewable Fuels Module National Energy Modeling System*, February 24, 1993.

Princeton Economic Research, Incorporated, *Software Overview Report for Wind Electric Submodule Renewable Fuels Module National Energy Modeling System*, March 29, 1993.

Schweizer, T. and Cohen, J., "A Technique for Estimating Project Risk: Beyond Traditional Sensitivity Analyses," Science Applications International Corporation, *Proceedings of the Windpower '88 Conference*, September 18-22, 1988.

Wiser, R. and M. Bollinger. "2012 Wind Technologies Market Report." U.S. Department of Energy. August 2013.

Appendix 3-D: Model Abstract

Model name:
Wind Energy Submodule

Model acronym:
WES

Description:
Resource quality data and the yearly capacity factor are used to calculate wind farm performance data on a sub-yearly level, as required by the EMM. Calculations are made for each time slice, wind class, and region.

Purpose of the model:
The purpose of the Wind Energy Submodule (WES) is to project the cost, performance, and availability of wind-generated electricity and to provide this information to the Electricity Capacity Planning (ECP) component of the Electric Market Module (EMM) for projecting the building of new wind capacity in competition with other sources of electricity generation.

Most recent model update:
March 2016.

Part of another model?:
The Wind Energy Submodule is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

Official model representative:
Cara Marcy
Renewable Electricity Analysis Team
Office of Electricity, Coal, Nuclear and Renewables Analysis
U.S. Energy Information Administration, EI-34
1000 Independence Ave., SW
Washington, DC 20585
Phone: (202) 586-9224
e-mail: cara.marcy@eia.gov

Documentation:
NEMS Documentation Report: R*enewable Fuels Module of the National Energy Modeling System*, May 2017.

Archive media and installation manual(s):

Archived as part of the NEMS production runs.

Energy system described:

A hybrid of various existing and proposed horizontal axis wind turbines for both onshore and offshore application.

Coverage:

- Geographic: 22 EMM regions
- Time/Unit Frequency: Annual through 2040
- Products: Electricity
- Economic Sectors: Electric utility sector, nonutility generators (NUGS)

Modeling features:

- Model Structure: Sequential calculation of available wind capacity by EMM region, wind class, and year with a deduction of each projection year's installed capacity from the remaining available capacity
- Modeling Techniques: Accounting function of available windy land area and conversion of land area to swept rotor area and then to available generation capacity, taking system reliability effects into account.
- Special Features: Accounting for policy and/or production incentives.

DOE input sources:

U.S. Energy Information Administration, *Annual Energy Review*.

U.S. Energy Information Administration, *Power Plant Operations Report,* Form EIA-923.

Pacific Northwest Laboratory, Reports PNL-7789, DOE/CH 10093 4, and PNL-3195.

U.S. Department of Energy and Electric Power Research Institute, "TVP Project-at-a-Glance" for Big Spring, Texas Project; Iowa Distributed Generation Project; and Wisconsin Low-Speed Wind Turbine Project.

Wiser, R. and M. Bollinger, "2012 Wind Technologies Market Report." U.S. Department of Energy. August 2013.

U.S. Energy Information Administration, *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, November 2016.

U.S. Energy Information Administration, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants," April 2013.

National Renewable Energy Laboratory, Renewable Energy Deployment System (REeDS) data pre-processor.

Non-DOE input sources:

None.

Independent expert reviews conducted:

None.

Status of evaluation efforts by sponsor:

None.

Appendix 3-E: Data Quality and Estimation Processes

This Appendix discusses (1) the quality of the principal sources of input data used in the Wind Energy Submodule, along with the user-defined parameters and guidelines used to select them, and (2) estimation methods used to derive parameters.

Wind resources of the United States have been extensively charted and classified by the Pacific Northwest Laboratory (PNL) (See Elliott, 1986 in the Bibliography section of Appendix 3-C), with a current effort by the National Renewable Energy Laboratory (NREL) underway to refine these estimates based on modern computer modeling and geographic information systems (GIS) techniques. Four classes of wind resources, based on average annual wind speeds, are generally used. These classes correspond to PNL Class 3 winds and higher, (speeds greater than 5.1 m/s (11.5 mph)) which represent the assumed lowest economic limit of wind speeds for grid-connected systems in the United States.

Data on wind resource quantity are maintained in the *WESAREA* input file. It contains regional data on the land area (in square kilometers) estimated to be available for wind plant development, accounting for the exclusion of some land as a result of legal, environmental, and land-use considerations. The methodology for these exclusions was developed with the assistance of wind resource modelers, meteorological consultants, the Department of Energy Office of Energy Efficiency and Renewable Energy, EIA, and NREL, based on prior versions of the NEMS wind resource data. The criteria are applied as follows to data developed and collected by NREL:

- 100% exclusions of areas with slope > 20% (updated data) or application of terrain exposure factor (1987 data).
- Environmental exclusions
- 100% exclusion of all National Park Service and Fish and Wildlife Service lands
- 100% exclusion of federal lands with a specific designation that seem incompatible with wind development (parks, wilderness, wilderness study area, wildlife refuge, wildlife area, recreation area, battlefield, monument, conservation areas, and wild and scenic rivers)
- 100% exclusion of state parks and conservation areas
- 50% exclusion of remaining Forest Service, Department of Defense, and state forest lands
- Land use exclusions
- 100% exclusion of water, wetlands, urban areas and airports/airfields
- 50% exclusion of non-ridge crest forest
- 100% exclusion of a 3 kilometer area surrounding 100% environmental and land use exclusions, except water exclusion
- Minimum density criteria of 5 square kilometers per 100 square kilometers of class 3 or better wind resource, after the 100% exclusions have been applied

The WESAREA input file describes the variations in wind resource on a daily and seasonal basis, and estimates wind output during the different load condition subperiods to analyze the correlation with load profiles. The data for this file was developed by NREL for EIA. The file also contains information on Load Duration Curve (LDC) subperiod definitions outside of the WES and the subperiod energy

percentages. From this, WES estimates a capacity factor for a given subperiod. The specific subperiods correspond to seasons and times of day.

Data on the cost of installed wind turbines is based on a comprehensive report commissioned by EIA in 2013 that evaluated, on a consistent basis, the capital cost of a wide variety of electricity generation technologies. Further validation of the estimates for wind energy technologies were conducted through peer review of the source data, as well as by a review of publicly available reports.

Data on the performance of wind turbines installed in the United States extends back to the mid 1980's. Estimates used in NEMS result from an analysis of historical performance of U.S. wind generating stock, with capacity factor estimates for each wind class based on a binning analysis of the observed capacity factor performance for plants in service and reporting generation data for each month of 2014.[17] Estimates for future capacity factor improvements are based on EIA analyst judgment from an analysis of vintage-wise performance from the historical record.

---

[17] Based on data collected in the Form EIA-923 and predecessor forms. See http://www.eia.gov/cneaf/electricity/page/eia906_920.html. Additional validation of these trends can be found in Wiser, et al., 2014 Wind Technologies Market Report. Lawrence Berkeley National Laboratory. August 2015. https://emp.lbl.gov/publications/2014-wind-technologies-market-report.

4. Solar Submodule

Model purpose

The solar submodule SOLAR estimates supply characteristics for grid-connected central station photovoltaic (PV) and solar thermal (ST) electricity-generating power plants. SOLAR does not characterize distributed or off-grid solar technologies. PV and ST cost and performance characteristics, which are defined consistently with fossil-fuel and other generating technology characteristics, reside in ECPDAT. ECPDAT is a data file resident in the Electricity Capacity Planning (ECP) Submodule of the EMM. Performance characteristics unique to these technologies (such as month- and region-dependent capacity factors), however, are passed to the EMM via the solar submodule SOLAR. Because solar radiation varies, capacity factors for solar technologies are assumed to vary by time of day, by month, and by region. Factors are provided for all regions for PV. Capacity factors for solar thermal are only provided for the regions with sufficient direct normal insolation to support potentially cost-effective solar thermal installations. This includes the following EMM regions:

Region number	Region acronym	Region description
1	ERCT	Texas ERCOT
2	FRCC	Florida FRCC
4	MROW	MRO West
17	SPNO	SPP North
18	SPSO	SPP South
19	AZNM	WECC Southwest
20	CAMX	WECC California
21	NWPP	WECC Northwest
22	RMPA	WECC Rockies

Relationship of the Solar Submodule to other models

SOLAR assigns performance data to global variables to be used by the EMM. SOLAR does not interact with other submodules of the RFM or NEMS.

Modeling rationale

Theoretical approach

Solar energy supplies are fundamentally different from those for most other renewable sources. It is appropriate to model other renewables such as wind, geothermal, and biomass with upward-sloping supply functions, since these renewables are characterized by having limited quantities of high-quality resources. In contrast, the solar resource within each EMM region for both kinds of solar technologies (ST and PV) is relatively constant for supply quantities and well in excess of conceivable demand. As a result, the supply for solar is assumed to be perfectly elastic at any moment. NEMS does not increase the cost of the resources with increasing quantities supplied, because high-quality resource sites are not exhausted.

Since the two solar electric technologies generate electricity in fundamentally different ways, the nature of the solar resource for each technology is significantly different. The most important difference is the nature of the solar radiation (insolation) that each technology uses. ST technology can utilize only direct normal insolation while PV can utilize both direct and diffuse insolation. Direct normal insolation is defined as sunlight arriving at a location in a path directly from the sun onto a surface without being scattered or reflected. Diffuse insolation is sunlight that has been scattered by clouds, fog, haze, dust, or other substances in the atmosphere and arrives at a location indirectly. The sum of direct normal and diffuse insolation is also referred to as global insolation.

The submodule uses a single type of each of the ST and PV technologies for all regions. Accordingly, capital and O&M costs and the efficiency in converting sunlight into electric energy are held constant across regions. Differences in regional resources are captured through the capacity factor variable that represents the solar energy input to the technology.

The default ST electric technology is a 100 MW solar-only central receiver (power tower) with a partial-load natural gas boiler for use in the startup cycle and temporary cloudy periods. The default PV technology is a 150 MW single-axis tracking flat-plate array tilted at an angle equal to the site's latitude.

Fundamental assumptions

The regional classification plan is the same for both ST and PV. As an input to EMM, SOLAR operates on the same 22 regions as EMM, which correspond to regions or subregions of the eight North American Electric Reliability Corporation Regions (see EMM documentation).

SOLAR contains distinct time-of-day and monthly capacity factors for each EMM region for both ST and PV, where applicable. The capacity factors are calculated based on a solar irradiance database developed by NREL. The Typical Meteorological Year (TMY) data contains hourly solar radiation by components—global, direct, and diffused—for over 1,400 weather stations across the U.S. through a period of 44 years (1962-2005).

Short-Term cost adjustment factors

Both PV and ST technologies are subject to short-term capital cost adjustment factors, wherein large annual increases in capacity are assumed to raise costs because of supply bottlenecks. There is, however, no resource constraint cost associated with solar generating technologies as for wind generating technologies.

Solar Submodule structure

Submodule flow diagram
A flow diagram showing the main computational steps and relationships of the Solar Submodule is shown in Figure 3.

Key computations and equations
SOLAR passes data to EMM directly, without any computations, through assignments to the appropriate COMMON variables. These are the utility generating capacities and subperiod capacity factors for each technology.

Figure 3. Solar energy submodule flowchart
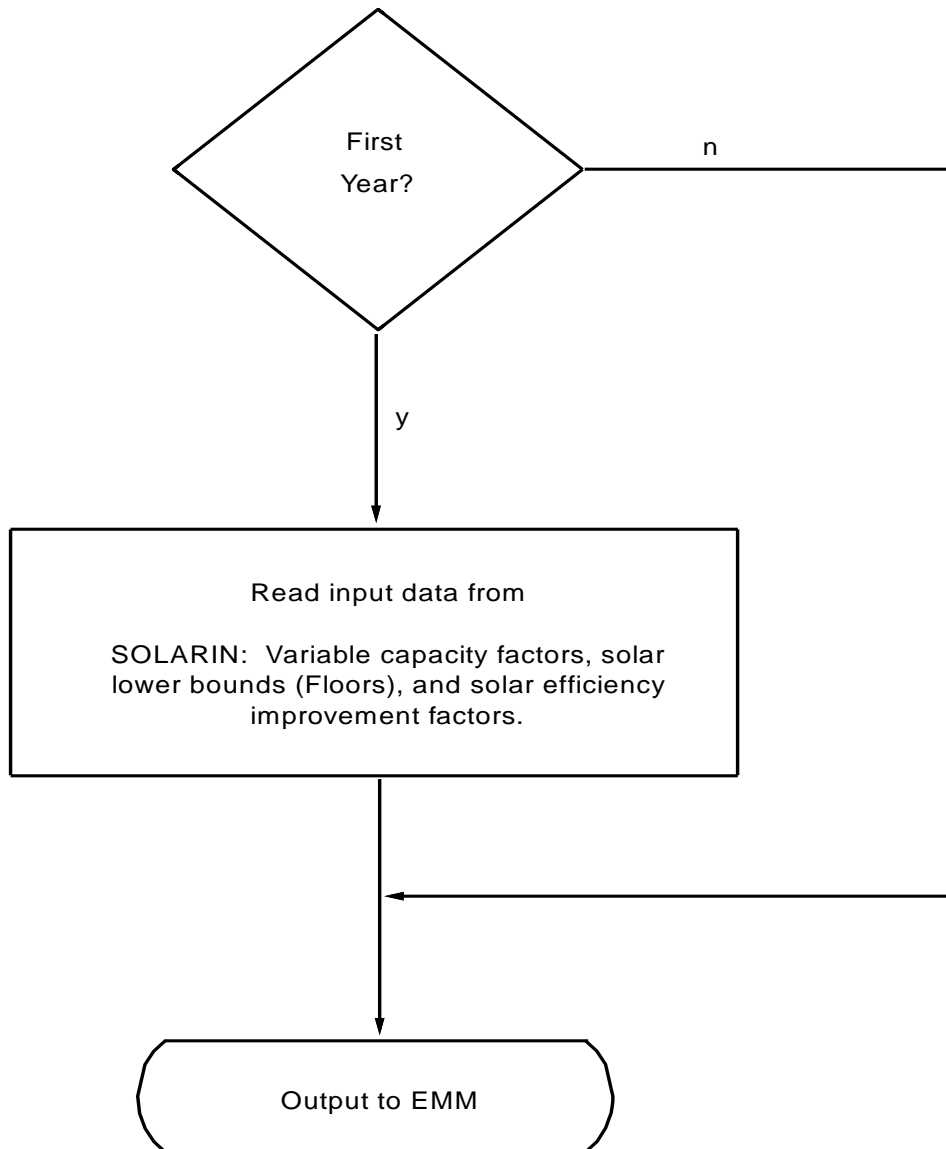
Appendix 4-A: Inventory of Variables, Data, and Parameters

This Appendix describes the variables, data inputs, and parameter estimates associated with the cost/performance characteristics of the two solar technologies. PV and ST cost and performance characteristics that are defined consistently with fossil and other generating technology characteristics reside in ECPDAT. Performance characteristics unique to these technologies (such as season and region-dependent capacity factors), however, are passed to the EMM via the solar submodule SOLAR.

Table 4A-1 provides a tabular listing of model variables and parameters. The table contains columns with information on item definitions, data sources, and measurement units.

The remainder of Appendix 4-A consists of detailed descriptions of data inputs and variables, including discussions on supporting data assumptions and transformations.

Table 4A-1. NEMS solar model inputs and outputs

Model Variable	Definition and Dimensions	Source	Units
INPUT DATA			
EFFMULPV	Efficiency multiplier for photovoltaic technology (currently set to 1).	EIA, expert judgment	Unitless
EFFMULST	Efficiency multiplier for solar thermal technology (currently set to 1).	EIA, expert judgment	Unitless
UPCLYR*	Construction period.	CEC, 1993.	Years
UPCPRO*	Completion fraction.	CEC, 1993.	Percent
UPFOM*	Fixed O&M cost for solar thermal technology.	EIA, 2013.	mills/kW
UPFOM*	Fixed O&M cost for photovoltaic technology.	EIA, 2016.	mills/kW
UPICCF*	Investment policy incentive as a fraction of capital cost.	Energy Improvement and Extension Act of 2008.	Percent
UPOVR *	Capital cost of solar thermal technology.	EIA, 2013.	$/kW
UPOVR *	Capital cost of photovoltaic technology.	EIA, 2016.	$/kW
*UPVOM *	Variable O&M cost for solar thermal technology.	EIA, 2013.	mills/kWh
UPVOM	Variable O&M cost for photovoltaic technology.	EIA, 2016	mills/kWh
WCAPVEL	Capacity constraints for photovoltaic technology in EMM region *n* in year *y* (not currently used).	EIA Estimates.	MW
WCASTEL	Capacity constraints for solar thermal technology in EMM region *n* in year *y* (not currently used).	EIA Estimates.	MW
WSSPVEL	Prototype photovoltaic system capacity factor for EMM region *n* in time period *p* in year *y*.	NREL, 2010.	Percent
WSSSTEL	Prototype solar thermal system capacity factor for EMM region *n* in time period *p* in year *y*.	NREL, 2010.	Percent

*Assigned in EMM input file ECPDAT.

MODEL INPUT: *EFFMULPV*

DEFINITION: Solar PV efficiency improvement factors.

The efficiency multiplier with values greater than 1.0 allows SOLAR to model system improvements that increase the capacity factor. The current efficiency multiplier is assumed to be 1.0 for all years. Not all efficiency improvements are captured in this variable. For example, improvements in PV cell conversion efficiency are reflected in the capital cost variable.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources.

MODEL INPUT: *EFFMULST*

DEFINITION: Solar thermal efficiency improvement factors.

The efficiency multiplier with values greater 1.0 allows modeling system improvements that increase the capacity factor by utilizing lower energy solar insolation. The current efficiency multiplier is assumed to be 1.0 for all years.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources.

MODEL INPUT: *UPCLYR*

DEFINITION: Construction period of technology *t*, years.

The construction period for a PV facility is assumed to be 2 years.

SOURCES: EIA, expert judgment following discussions with industry, government, and national laboratory sources.

MODEL INPUT: *UPCPRO*

DEFINITION: Fraction of construction of technology t completed in year *y* (percent).

The model assumes new solar plants are constructed over a two-year period with most capital costs allocated in the annual proportions of 10% in the first year and 90% in the final year.

SOURCES: EIA, expert judgment following discussions with industry, government, and national laboratory sources.

MODEL INPUT: *UPFOM (21)*

DEFINITION: Fixed O&M cost for photovoltaic technology in EMM region *n* and year y ($/kW).

SOURCE: U.S. Energy Information Administration, *Capital Cost Estimates for Utility Scale Electricity Generation Plants*, November 2016.

MODEL INPUT: *UPFOM (19)*

DEFINITION: Fixed O&M cost for solar thermal technology in EMM region *n* and year *y* ($/kW).

SOURCE: U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants*, April 2013.

MODEL INPUT: *UPICCF*

DEFINITION: Investment policy incentive for technology *t* and year *y* ($/kW).

This is currently set at 30% of the capital cost, as the result of the December 2015 budget reconciliation bill, for solar projects under construction before the end of 2019. Solar projects starting construction in 2020 and 2021 qualify for credits of 26% and 22%, respectively. The credit becomes permanent at 10% of capital costs for projects starting construction after 2021.

SOURCE: Consolidated Appropriations Act of 2016, H.R. 2029, 114th Cong.

MODEL INPUT: *UPOVR (21)*

DEFINITION: Capital cost for PV technology in EMM region *n* and year *y* ($/kW).

SOURCE: U.S. Energy Information Administration, *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, November 2016.

MODEL INPUT: *UPOVR (19)*

DEFINITION: Capital cost for solar thermal technology in EMM region *n* and year *y* ($/kW).

SOURCE: U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants*, April 2013.

MODEL INPUT: *UPVOM (21)*

DEFINITION: Variable O&M costs in EMM region *n* and year *y*

The variable O&M costs for the PV technology are set to zero for all EMM regions and all years.

SOURCE: U.S. Energy Information Administration, *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, November 2016.

MODEL INPUT: *UPVOM (19)*

DEFINITION: Variable O&M costs in EMM region n and year y

The variable O&M costs for the ST technology are set to zero for all EMM regions and all years.

SOURCE: U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants*, April 2013.

MODEL INPUT: *WCAPVEL*

DEFINITION: Constraint for PV capacity resource in EMM region *n*; and year *y* (MW).

The variable can be used to set minimum or maximum capacity constraints for ST on a regional and yearly basis, but is not currently used to do either.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources.

MODEL INPUT: *WCASTEL*

DEFINITION: Constraint for solar thermal capacity resource in EMM region n; and year y (MW).

The variable can be used to set minimum or maximum capacity constraints for ST on a regional and yearly basis, but is not currently used to do either.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources.

MODEL INPUT: *WSSPVEL*

DEFINITION: Time segment system capacity factor for PV in EMM region *n* in time period *p* in year *y* (Percent).

SOURCE: National Renewable Energy Laboratory, work performed for EIA.

MODEL INPUT: *WSSSTEL*

DEFINITION: Time segment capacity factor for solar thermal system in EMM region *n* in time period *p* in year *y* (Unitless).

The solar thermal capacity factors by region and time segment are calculated using NREL data that is based on typical meteorological year (TMY3) solar resource data from the National Solar Radiation Database processed through the Solar Advisor Model.

SOURCES: National Renewable Energy Laboratory, work performed for EIA.

Appendix 4-B: Mathematical Description

The SOLAR submodule does not incorporate any modeling equations. It assigns values that are read from input files to the appropriate RFM common blocks.

Appendix 4-C: Bibliography

Consolidated Appropriations Act of 2016, H.R. 2029, 114th Cong. § 187 (2016).

U.S. Energy Information Administration, *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, November 2016.

U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants*, April 2013.

Appendix 4-D: Model Abstract

Model name:

Solar Submodule

Model acronym:

SOLAR

Description:

SOLAR defines costs and performance characteristics for photovoltaic and solar thermal electricity generating systems by EMM region and year. EMM regions are based on the North American Electric Reliability Corporation (NERC) regions as modified by the U.S. Energy Information Administration (EIA) for NEMS. For PV technologies, all 22 EMM regions are represented in SOLAR. For ST technologies, however, only nine selected regions are represented, since insufficient direct normal insolation (sunlight) bars this technology from other regions of the country.

Purpose of the model:

The purpose of the NEMS Solar Submodule (SOLAR) is to define the costs and performance characteristics of Solar Thermal (ST) and Photovoltaic (PV) electricity generating technologies and to pass them to the EMM for capacity planning decisions.

Most recent model update:

March 2016.

Part of another model?:

The Solar Submodule is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

Official model representative:

Manussawee Sukunta
Renewable Electricity Analysis Team
Office of Electricity, Coal, Nuclear and Renewables Analysis
U.S. Energy Information Administration, EI-34
1000 Independence Ave, SW
Washington, DC 20585
(202) 586-0279
e-mail: manussawee.sukunta@eia.gov

Documentation:

Renewable Fuels Module of the National Energy Modeling System: Model Documentation 2016.

Archive media and installation manual(s):

Archived as part of the NEMS production runs.

Energy system described:

The default solar thermal electric technology is a 100-MW central receiver (power tower) with a partial-load natural gas boiler for use in the startup cycle and temporary cloudy periods, and without integrated storage. At low levels of insolation the output of the central receiver system is zero, until the insolation exceeds a threshold level sufficient to overcome thermal losses. The representative PV technology is a 150-MW single-axis tracking, flat-plate array tilted at an angle equal to the site's latitude.

Coverage:

- Geographic: 22 EMM regions, which correspond to regions or subregions of the eight North American Electric Reliability Corporation (NERC) Regions (see EMM documentation).
- Time Unit/Frequency: Annual through 2040.
- Products: Electricity.

Modeling features:

Non-DOE input sources:

California Energy Commission: Cost and performance characteristics, solar thermal technology.

Electric Power Research Institute and U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Technology Characterizations (EPRI TR-109496, December 1997).

Electric Power Research Institute: Cost and performance characteristics, PV technology.

IRS Tax Code

- Investment tax credit.

National Renewable Energy Laboratory

- Regional capacity factors, by month and time of day

DOE input sources:

U.S. Energy Information Administration, *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, November 2016.

U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants*, April 2013.

Independent expert reviews conducted:

None.

Status of evaluation efforts by sponsor:

None.

Appendix 4-E: Data Quality and Estimation Processes

This Appendix discusses (1) the quality of the principal sources of input data used in the Solar Submodule.

Solar thermal performance

Solar thermal performance (capacity factor) is based on a parabolic trough system without storage capacity. Because it uses concentrators, the concentrating solar power system can utilize only direct insolation. Due to limitations on the technology-specific resource data, the technology assumption underlying the performance data diverges from the assumption underlying the cost estimates, which assume a central receiver technology. Solar thermal performance estimates are obtained from the National Renewable Energy Laboratory, which processed solar resource data through its technology-specific Solar Advisor Model to estimate capacity factors. Solar capital cost estimates are from EIA's *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* (April 2013). In all cases, characteristics selected for EIA use are compared with any other available measures or estimates, as obtained from state or federal government offices, industry, trade, and private research and analysis firms.

All cost and performance estimates are made available for review within EIA; they are also circulated for comment among appropriate DOE offices in the Office of Energy Efficiency and Renewable Energy's Office of Power Technologies; finally, the estimates are made available for outside uses and comment, both in response to specific requests and in EIA-sponsored forums.

Photovoltaic performance

Photovoltaic performance is based on a single-axis tracking PV system. Performance estimates are from the National Renewable Energy Laboratory, which processed typical meteorological year data from the National Solar Radiation Database solar resource data through its technology-specific Solar Advisor Model. Photovoltaic system cost estimates share the technology assumptions used to generate performance estimates and are based on EIA's *Capital Cost Estimates for Utility Scale Electricity Generating Plants* (November 2016).

5. Biomass Submodule

Model purpose

Biomass Submodule sends regional biomass fuel price and quantity information to support projected decisions for the construction and operation of biomass electricity generation in the Electricity Market Module (EMM) and the construction and operation of cellulosic ethanol, pyrolysis oils, and biomass-to-liquids plants in the Liquid Fuels Market Module (LFMM) of the National Energy Modeling System (NEMS).

The biomass supply schedule is based on the accessibility of biomass resources to the consuming sectors from existing wood resources, agricultural residues, and biomass energy crops. The regional biomass supply schedule has multiple feedstock components: dynamically generated each model year using the Policy Analysis Model (POLYSYS), developed by the University of Tennessee, and statically taken from feedstock supply schedules provided by Oak Ridge National Laboratory (ORNL). Urban wood wastes and mill residues supply also have a dynamically-determined component that is calculated by using feedback data on the industrial waste wood supply from the Industrial Demand Module (IDM) in NEMS.

Cost and performance characteristics of a representative biomass combustion system were determined through a study performed by Leidos, Inc., and reside in the EMM input file ECPDAT. Cost and performance characteristics of biofuels production facilities reside in the LFMM. Performance characteristics unique to the biomass direct-combustion system (such as heat rates and variable O&M costs) are computed in the renewables submodule and then passed to the EMM. The fuel component of the cost characteristic is determined from the regional biomass supply schedules and then converted to a variable O&M cost.

Relationship of the Biomass Submodule to other models

The Biomass Submodule interacts with EMM, LFMM, and the sectoral demand modules. It does not interact with other submodules in the RFM. Regional biomass consumption requirements from the petroleum and electricity modules are used in the Biomass Submodule to determine the regional biomass supply price, for use in biofuels production, and a separate price for all other users. Information on the total biomass demand from the liquid fuels and electricity is passed to the biomass supply subroutine with each complete solution cycle of NEMS, so that the supply reflects the total available supply net of the consumption by other users.

In addition, projected regional supply of urban wood waste and mill residue interacts with the IDM. A portion of biomass that is generated as an industrial byproduct, and is not consumed in the industrial sector, is added to the biomass supply as an eligible resource for electricity generation or biofuels production. The urban wood waste supply from the IDM is then added to the noncaptive urban wood waste supply (see following sections) from the WODSUPP input file for each model year.

Modeling rationale

Theoretical approach

Biomass use is modeled in NEMS as two distinct markets: the captive and noncaptive biomass markets. The captive market includes users with dedicated biomass supplies such as black liquor or other byproducts resulting from manufacturing processes. Biomass waste combustion in captive markets serves the dual role of energy supplier and waste disposal method. The captive biomass market is modeled in the Industrial Demand Module (IDM) of NEMS. Leftover biomass that is not used in the industrial process is passed from the IDM to the RFM as eligible fuel for electric power plants.

The noncaptive biomass market includes the electric utility sectors and the biofuels production sector. The noncaptive markets serving residential and commercial uses of biomass are modeled in the residential and commercial demand modules, respectively.

The fuel supply schedule in each region defines the quantity and cost relationships of biomass resources accessible by all noncaptive consumers (electric power and biofuels), after accounting for demand by each sector. The four sectors represented are: (1) urban wood waste and mill residues, (2) forestry residues from federal forests, (3) agricultural residues and energy crops and (4) forestry residues from non-federal forests. Additional detail on the biomass supply curves is provided in Appendix 5-E.

Fundamental assumptions

The Biomass Submodule assumes all sectors using noncaptive biomass will compete for the same supplies subject to particular uses in each respective sector. As such, EIA assumes that cellulosic ethanol plants will not be able to use supplies from urban wood and mill waste, and that neither cellulosic ethanol, pyrolysis oils, nor biomass-to-liquids (biomass Fischer-Tropsch) will be able to use feedstocks from federal forests. However, the power sector can utilize all biomass resources included in the model. Because urban wood and mill wastes are likely the lowest-cost biomass resources, the cellulosic ethanol sector is assumed to pay premium prices with respect to the power sector for biomass resources. It is also assumed that there are no discounts for large orders of biomass.

To simplify the modeling of the economic accessibility to the resource, the Biomass Submodule assumes a fixed "typical" transportation distance in calculating costs for agriculture residues and energy crops, forestry residues, and urban wood waste. The maximum distance to economically transport all biomass resources, except urban wood waste, is assumed to be 50 miles. Within this 50-mile radius, the transportation cost is $12/dry ton, which gets added to the supply curves for both forestry residues and agricultural residues and energy crops to reflect the transportation cost from the farm-gate to the power plant. The transportation cost is expressed in 2008$, escalated by inflation rate annually, and indexed to the price of crude oil.

Alternative approaches

Generally, biomass conversion can be modeled similar to other solid fuel technologies, such as coal, with appropriate attention to cost assumptions. The unique characteristics of this resource reside in the treatment of the fuel supply function, as well as interaction between the ethanol and power sector users of the biomass resource.

The Biomass Submodule of the RFM has several simplifying features of its supply functions which may offer opportunities for improvement. The submodule treats only the marketed portion of the fuel, when there could be interaction with entities with captive biomass supply, i.e. the forest products industry, as well as with the residential fuel market. Another simplification is the assignment of a constant factor for transportation costs. The fuel transport costs could be a significant share of the delivered costs and will vary considerably by terrain and distance to the conversion facility. A final limiting assumption pertains to the treatment of competing uses of the resource, either as land or as other product uses. For example, the land could be used for other fiber or food crops or the wood could be used for construction, at alternate prices.

Biomass Submodule structure

Submodule flow diagram
A flow diagram showing the main computational steps and relationships of the Biomass Submodule is shown in Figure 4.

### Key Computations and Equations
The Biomass Submodule consists of one Fortran subroutine and a call to the POLYSYS model, which runs as a separate submodule within the RFM. The regional biomass supply price is calculated based on the current regional biomass consumption passed from the industrial demand, liquid fuels market, and electricity market modules. These biomass supplies are then passed back to the EMM and LFMM to provide price and availability data to these two modules.

Biomass resources come from three category sources: (1) urban wood waste and mill residues, (2) agricultural residues and dedicated energy crops, and (3) forestry residues from federal and non-federal forests. Because biofuels producers may be limited in their ability to use particular feedstocks, the user may specify a fraction of each of the four sectors to use to determine the ethanol feedstock price. The price of fuel to the power sector is determined from the residual biomass supply, after accounting for liquid fuels demand. Because each of the users of biomass may face different limitations in source-of-supply, the converged price for biomass will not necessarily be the same across the sectors, even though they share some amount of supply.

The biomass quantity-price relationships are implemented in a matrix representing the supply curve as step functions for each of the four resource sectors. These individual matrices are aggregated based on user specifications for the biofuels and (separately) the power sector. A linear interpolation scheme on the aggregate sector supply curve is used to determine the biomass price given a biomass quantity.

Since the biomass consumption data in the industrial and refining sectors are defined in NEMS by Census divisions, and the costs and quantities of biomass feedstocks are defined for coal market regions, a geographic mapping was necessary to generate biomass prices by Census division.

Figure 4. Biomass submodule flowchart
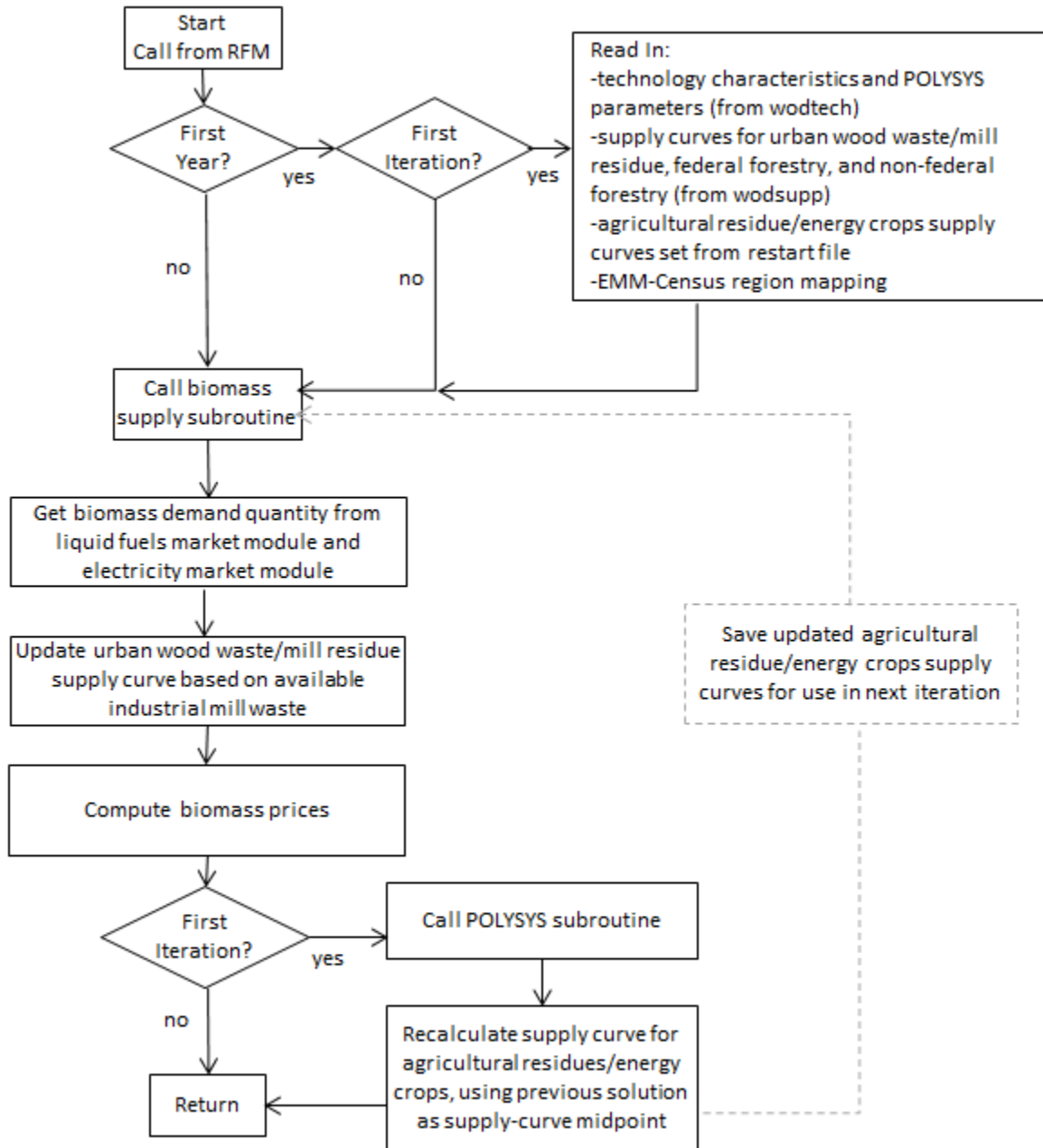
Appendix 5-A: Inventory of Variables, Data and Parameters

Appendix 5-A provides information on variables used in the Biomass Submodule. Table 5A-1 gives a complete listing of all variables including definitions and dimensions, sources, measurement units, and page references. Variables are classified as Submodule data inputs, calculated variables, and Submodule outputs. Following Table 5A-1 are detailed descriptions of each input data item.

Table 5A-1. NEMS Biomass Submodule inputs and variables

Variable	Definition and Dimensions	Source	Units
INPUT DATA			
$CDTOCLWDTI$	Conversion factors for converting Census division r to coal demand region n	EIA	Unitless
$WDSUP\_Q_{n,y,l,f}$[18]	Biomass quantity step function in coal demand region n, year y, step I, feedstock f	EIA	trillion Btu
$WDSUP\_P_{n,y,l,f}$[18]	Biomass price step function in coal demand region n, year y, step I, feedstock f	EIA	\$/MMBtu
$UPOVR*$	Capital cost for biomass technology	EIA, 2013	\$/kW
$UPMCF*$	Capacity factor for biomass technology electricity sector	EIA, 2013	Unitless
$UPVOM*_{n,y}$	Variable O&M cost component for biomass technology electricity sector in EMM region n in year y	EIA, 2013	\$/MMBtu
$UPFOM_{n,y}*$	Fixed O&M costs for biomass technology electricity sector in EMM region n in year y	EIA, 2013	\$/kW
$WHRBMEL_{n,y}$	Heat rate for biomass technology in EMM region n in year y	EIA, 2013	Btu/kWh
VARIABLES			
$QBMCM$	Quantity of biomass consumed in the commercial sector in Census division r in year y	NEMS	trillion Btu
$QBMIN$	Quantity of biomass consumed in the industrial sector in Census division r in year y	NEMS	trillion Btu
$QBMPWCL$	Quantity of biomass consumed in the electric power sector in coal demand region n in year y	NEMS	trillion Btu
$QBMETCL$	Quantity of biomass consumed in the refining sector (for cellulosic ethanol production) in coal demand region n in year y	NEMS	trillion Btu
$QBMBTCL$	Quantity of biomass consumed in the refining sector (for biomass-to-liquids production) in coal demand region n in year y	NEMS	trillion Btu
$POLYPTQ$	Demand quantity sent to POLYSYS for each coal demand region	NEMS	trillion Btu
OUTPUTS			

---

[18] Note that for the agricultural residues/energy crops feedstock, this variable is an output.

Variable	Definition and Dimensions	Source	Units
PBMASCL$_{n,y,f}$	Price of biomass for all sectors in coal demand region *n* and year *y* for feedstock *f*.	NEMS	$/MMBtu
PLYSUP_Q_AG	POLYSYS supply curve quantities for agricultural residues/energy crops, by coal region, step, and year	RFM/POLYSYS	trillion Btu
PLYSUP_P_AG	POLYSYS supply curve prices for agricultural residues/energy crops, by coal region, step, and year	RFM/POLYSYS	$/MMBtu
WCABMEL$_{n,y}$	Capacity for utilities in EMM region *n* in year *y*	EMM	MW
WVCBMEL$_{n,y}$	Variable O&M costs for biomass technology electricity sector in EMM region *n* in year *y*. Incorporated the converted fuel cost for biomass.	RFM	mills/kWh

*Assigned in EMM input file ECPDAT.

MODEL INPUT: *CDTOCLWDTI*

DEFINITION: Conversion factors for converting data for Census division *r* to data for coal demand region *n*.

SOURCE:

Oak Ridge National Laboratory, "Data and Sources Biomass Supply." Draft prepared for EIA under Contract No. DE-AC05-84OR21400, Oak Ridge, TN, June 27, 1993.

MODEL INPUT: *WDSUP_Q*

DEFINITION: Quantity of biomass supply in coal demand region *n*, year *y*, and step *I*.

WDSUP_Q is part of the biomass supply schedule. The variable represents quantity of a biomass composite consisting of the following biomass types: (1) urban wood waste and mill residues, (2) forest residues from federal forests (3) agricultural residues and energy crops, and (4) forest residues from non-federal forests

SOURCES:

Ugarte, Daniel and the University of Tennessee Department of Agricultural Economics. POLYSYS model projections.

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

MODEL INPUT: *WDSUP_P*

DEFINITION: Price of biomass supply in coal demand region *n*, year *y*, and step *I*.

WDSUP_P is part of the biomass supply schedule. The variable represents the price of a biomass composite consisting of the following biomass types: (1) urban wood waste and mill residues, (2) forest residues from federal forests, (3) agricultural residues and energy crops, and (4) forest residues from non-federal forests

SOURCES:

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

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

Ugarte, Daniel and the University of Tennessee Department of Agricultural Economics. POLYSYS model projections.

MODEL INPUT: *UPOVR*

DEFINITION: Capital costs for electricity sector.

UPOVR represents the nth-of-a-kind capital cost for a direct combustion biomass technology of unit size 50 MW. The cost estimates incorporate the removal of interest during construction and contingency costs, which are added later in EMM.

SOURCE:

United States Department of Energy, U.S. Energy Information Administration, "Updated Capital Cost Estimates for Utility Scale Electricity Generation Plant," April 2013.

MODEL INPUT: *UPFOM*

DEFINITION: Fixed O&M costs for biomass technology.

The fixed O&M cost is assumed to be constant across all regions and for all years.

SOURCE:

United States Department of Energy, U.S. Energy Information Administration, "Updated Capital Cost Estimates for Utility Scale Electricity Generation Plant," April 2013.

MODEL INPUT: *UPVOM*

DEFINITION: Constant variable O&M costs for biomass technology.

SOURCE:

United States Department of Energy, U.S. Energy Information Administration, "Updated Capital Cost Estimates for Utility Scale Electricity Generation Plant," April 2013.

MODEL INPUT: *UPMCF*

DEFINITION: Capacity factor for the utility sector.

Capacity factor is assumed to be constant for all years and all regions.

SOURCE:

Craig, K.R.; Mann, M.K., 1993. Cost and Performance Analysis of Integrated Gasification Combined Cycle (IGCC) Power Systems Incorporating a Directly Heated Biomass Gasifier. Milestone Completion Report. NREL. December 1993.

MODEL INPUT: *WHRBMEL*

DEFINITION: Heat rate for biomass technology in EMM region *n* in year *y.*

The heat rate represents the biomass direct combustion technology.

SOURCES:

United States Department of Energy, U.S. Energy Information Administration, "Updated Capital Cost Estimates for Utility Scale Electricity Generation Plant," April 2013.

MODEL INPUT: *QBMCM*

DEFINITION: Biomass/wood consumption in commercial sector in Census division *r* and year *y*.

NEMS variable, calculated in the commercial demand model.

SOURCE:

NEMS.

MODEL INPUT: *QBMEL*

DEFINITION: Biomass/wood consumption in electric power sector in Census division *r* and year *y*.

NEMS variable, calculated in the EMM model.

SOURCE:

NEMS.

MODEL INPUT: *QBMIN*

DEFINITION: Biomass/wood consumption in industrial sector in Census division *r* and year *y*.

NEMS variable, calculated in the industrial demand model.

SOURCE: NEMS.

MODEL INPUT: *POLYPTQ*

DEFINITION: Demand quantity sent to POLYSYS for each coal demand region as midpoint for POLYSYS-generated supply curves.

SOURCE: NEMS.

MODEL OUTPUT: *WCABMEL*

DEFINITION: Available generating capacity in EMM region n and year *y*, in megawatts.

The maximal generating capacity is determined by the maximal value in each regional supply curve and converted into MW using the performance characteristics of the biomass technology, represented in the RFM.

SOURCE: NEMS.

MODEL OUTPUT: *WVCBMEL*

DEFINITION: Variable costs for biomass electricity generation for the utility sector in EMM region *n* in year *y*.

Variable cost is model-determined. It is the sum of two factors: (1) a constant factor accounting for operational maintenance expenses, and (2) fuel cost. Since there is no vehicle to pass fuel cost

separately to the ECP, the cost for biomass fuel is converted into mills per kWh and added as an additional variable O&M cost component.

SOURCE: NEMS.

MODEL OUTPUT: *PBMASCL*

DEFINITION: Price of biomass for all sectors for coal demand region n, year y, feedstock f

Price of biomass is model determined in the RFM based on input biomass demand quantities.

SOURCE: NEMS/RFM.

MODEL OUTPUT: *PLYSUP_Q_AG*

DEFINITION: POLYSYS supply curve quantities for agricultural residues/energy crops, by coal region, step, and year

SOURCE: NEMS/RFM/POLYSYS.

MODEL OUTPUT: *PLYSUP_P_AG*

DEFINITION: POLYSYS supply curve prices for agricultural residues/energy crops, by coal region, step, and year

SOURCE: NEMS/RFM/POLYSYS.

Appendix 5-B: Mathematical Description

The Biomass submodule does not incorporate any modeling equations. It allocates values that are read from input files and from other modules of NEMS, to the appropriate RFM common blocks.

Appendix 5-C: Bibliography

Antares Group Inc., "Biomass Residue Supply Curves for the U.S.," Landover, MD, September 1998.

Associates in Rural Development. *Impact of Large Biomass Demand Centers on the Forest Resource Base*. Report prepared for the Northeast Regional Biomass Program by Associates in Rural Development, Burlington, VT. National Technical Information Service, Springfield, VA. 1986.

Brower, M.C. et.al., Powering the Midwest, Union of Concerned Scientists, Andover, MA, 1993.

Craig, K.R.; Mann, M.K. 1993. Cost and Performance Analysis of Integrated Gasification Combined Cycle (IGCC) Power Systems Incorporating a Directly Heated Biomass Gasifier. Milestone Completion Report. National Renewable Energy Laboratory, December 1993.

Draper, H.M., R.T. Brooks, Jr., J.D. Thomas, and L.A. Weaver. *The Biomass Energy Potential of Mississippi*. Tennessee Valley Authority, Norris, TN and Mississippi Forestry Association, Jackson, MS. 1989.

Decision Analysis Corporation of Virginia, "Data Documentation for the Biomass Cost-Supply Schedule," prepared for the U.S. Energy Information Administration, Washington, DC, July 28, 1995.

Easterly, James L., *Biomass Supply Curve Enhancement Regarding Agricultural Residues*, Report for EIA, Sept., 2004.

Easterly, James, "*Biomass Gasification Technology Cost and Performance Assumptions*," August 2006.

E.C. Jordan Co. and Maine Audubon Society. *Biomass Chips: An Exploration of Problems and Opportunities*. Report prepared for the Northeast Regional Biomass Program by E. C. Jordan Co., Portland, ME and Maine Audubon Society, Falmouth, ME. National Technical Information Service, Springfield VA, 1985.

Electric Power Research Institute and U.S. Department of Energy, Office of Utility Technologies, "Renewable Energy Technology Characterizations," EPRI TR-109496, Palo Alto, CA, December 1997, accessible at http://www.eere.energy.gov/power/techchar.html .

Ellis, B.K. and J.A. Brown. *Production and Use of Industrial Biomass and Bark Residues in the Tennessee Valley*. TVA/ONRED/LER--86/1. Tennessee Valley Authority, Norris, TN, 1986.

English, Burton C. and Sean Coady. *The costs of producing biomass in the United States for selected land resource regions*. Unpublished document, 1990.

Gas Turbine Handbook, 1995 Handbook, Gas Turbine World.

Graham, R.L., et.al., Oak Ridge National Laboratory, *The Oak Ridge Energy Crop County Level Database*, September 20, 1996 version, Oak Ridge, TN.

Graham, R.L., et.al., "The Economics of Biomass Production in the United States", in *Second Biomass Conference of the Americas*, pp. 1313-1323, National Renewable Energy Laboratory, Golden, Colorado, 1995.

Grey, Ed, et.al., Antares Group Inc., "Expert Review of EIA Work to Update Biomass Gasification Technology Cost and Performance Assumptions," August 2006.

Hughes, Evan, "Biomass Cost Analysis," July 2006.

Klass, D.L. *The U.S. Biofuels Industry*. Paper presented at the International Renewable Energy Conference, Honolulu, Hawaii, September 18-24, 1988.

McElvenny, James, "Adding Value to Recycled Wood," C&D Debris Recycling, July 1994.

McKeever D. 2004. Inventories of Woody Residues and Solid Wood Waste in the United States, 2002. In Proceedings of the Ninth International Conference, Inorganic-Bonded Composite Materials. October 2004. Vancouver, British Columbia. 12 pp.

McKeever D. 1998. Wood residual quantities in the United States. Biocycle 39(1):65-68.

McQuillan, A., K. Skog, T. Nagle, and R. Loveless. *Marginal Cost Supply Curves for Utilizing Forest Waste Biomass in the United States*. Unpublished manuscript, University of Montana, Missoula, Montana, February 1984.

The POLYSYS Modeling Framework: A Documentation, Agricultural Policy Analysis Center, University of Tennessee. Web accessed at http://www.agpolicy.org/polysys.html on May 29, 2014.

Pletka, Ryan, et.al., Black and Veatch, "Biomass Gasification Assumptions Review," October 2006.

Rice, D., Presentation at EPRI-Sponsored Biomass Production Economics Workshop. Nashville, TN, October 22-23, 1992.

Skog, K. Presentation at EPRI-Sponsored Biomass Production Economics Workshop. Nashville, TN, October 22-23, 1992.

Stoll, H. And Todd, D.M., General Electric Company, *Current IGCC Market Competitiveness*, Schenectady, N.Y., November 10, 1996.

Turhollow, A.F. et al. "Data and Sources, Biomass Supply." Draft report prepared for the U.S. Energy Information Administration, U.S. Department of Energy, by Oak Ridge National Laboratory, Oak Ridge, TN, July 1993.

Turnbull, J. Presentation at EPRI-Sponsored Biomass Production Economics Workshop. Nashville, TN, October 22-23, 1992.

Trumble, D.A., *Biomass Energy II: Forecasts of Regional Sectoral Biomass Energy Consumption (1990-2010)*. Draft report submitted to U.S. Energy Information Administration, U.S. Department of Energy, October. Prepared by Oak Ridge National Laboratory, Oak Ridge, TN, 1991.

U.S. Department of Agriculture, *Forest Service, Forest Resources of the United States*, 1992, General Technical Report RM-234, September 1993 (Revised June 1994).

U.S. Department of Agriculture, Forest Service, RPA Assessment of the Forest and Rangeland Situation in the United States, 1993 Update, Forest Resource Report No. 27 (June 1994).

U.S. Department of Agriculture, Forest Service, *An Analysis of the Timber Situation in the United States: 1989-2040. A Technical Document Supporting the 1989 USDA Forest Service RPA Assessment*. General Technical Report RM-199. Rocky Mountain Forest and Range Experiment Station, Forest Service, U.S. Department of Agriculture, Fort Collins, CO., 1990.

U.S. Department of Agriculture, Forest Service, *U.S. Forest Facts and Historical Trends*, available at http://fia.fs.fed.us , Report number FS-696-M, June 2001.

U.S. Department of Energy, U.S. Energy Information Administration. *Updated Capital Cost Estimates for Utility Scale Electricity Generation Plant*, April 2013.

Perlack, R.D. and Stokes, B.J. (Leads), Oak Ridge National Laboratory, *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*, Oak Ridge, TN 227p. U.S. Department of Energy, ORNL/TM-2011/224.2011.

Walsh, Marie, Oak Ridge National Laboratory, "U.S. Bioenergy Crop Economic Analysis: States and Needs," *Biomass and Bioenergy*, vol. 14, pp. 341-350, 1998.

Walsh, Marie, et.al., Oak Ridge National Laboratory, "Economic Analysis of Energy Crop Production in the U.S.- Location, Quantities, Price, and Impacts on Traditional Agricultural Crops" pp. 1302-1310, in *Bioenergy 98: Expanding Bioenergy Partnerships*, Great Lakes Regional Biomass Energy Program, Chicago, Illinois, 1998.

Walsh, Marie, Oak Ridge National Laboratory, "Method to Estimate Bioenergy Crop Feedstock Supply Curves," *Biomass and Bioenergy*, vol. 18, pp. 283-289, 2000.

Walsh, Marie, et.al., Oak Ridge National Laboratory, "Evolution of the Fuel Ethanol Industry: Feedstock Availability and Price", Oak Ridge, TN, April 1998.

Young, Timothy M., et al, *Economic Availability of Woody Biomass Fuel Chips for 13 Southeastern States*, prepared for the Tennessee Valley Authority and the Southeastern Regional Biomass Energy Program, U.S. Department of Energy, TVA/LR/NRMB98/1, January 1989.

Appendix 5-D: Model Abstract

Model name:
Biomass Submodule.

Model acronym:
None.

Description:
The submodule passes projected cost and performance characteristics, by EMM region and year, to the EMM. The projected cost characteristic includes fuel cost, which is determined from the regional biomass supply curves and converted to a variable O&M cost.

Most recent model update:
October 2013.

Part of another model?:
The Biomass Submodule is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

Official model representative:
Chris Namovicz
Renewable Electricity Analysis Team,
Office of Electricity, Coal, Nuclear and Renewables Analysis
U.S. Energy Information Administration, EI-34
1000 Independence Ave., SW
Washington, DC 20585
Phone: (202) 586-7120
e-mail: chris.namovicz@eia.gov

Documentation:
NEMS Documentation Report: Renewable Fuels Module of the National Energy Modeling System, May 2017.

Archive media and installation manual(s):
Archived as part of the NEMS production runs.

Energy system described:
Non-captive biomass supply and associated price.

Coverage:
- Time Unit/Frequency: Annual through 2040
- Products: generating capacity
- Economic Sectors: electric utility and industrial sectors

Modeling features:

Data from nine Census divisions are restructured into 16 coal demand regions.

DOE input sources:

R.D. Perlack and B.J. Stokes (Leads), Oak Ridge National Laboratory, *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*, Oak Ridge, TN 227p. U.S. Department of Energy, ORNL/TM-2011/224.2011.

Independent expert reviews conducted:

None.

Status of evaluation efforts by sponsor:

None.

Appendix 5-E: Data Quality and Estimation Processes

Derivation of biomass supply curves

The biomass supply curve provides price and quantity information for four distinct feedstock categories. The four feedstocks are combined into one supply curve, representing available resources for each of the 16 coal demand regions. The three feedstocks represented in the supply curve are as follows:

- **Agricultural residues and dedicated energy crops** – This feedstock supply curve component is endogenously and dynamically calculated in EIA's version of the POLYSYS model, which was purchased from the University of Tennessee. The dedicated energy crops and agricultural residues include perennial grasses, coppice and other woody crops, corn stover, wheat straw, oat straw, sorghum stubble, and barley straw. The vast majority of the total energy crop feedstocks available comprise switchgrass, corn stover and wheat straw.   EIA oil price projections, which influence crop cultivation costs, are used as an input into the POLYSYS model, ensuring that production costs on agricultural lands are in agreement with EIA fuel cost assumptions.

  In the POLYSYS model, the price-quantity solution from the prior year is the starting point for planting decisions in the following year's supply curves. The RFM designates a set of additional quantities above and below the initial solution quantity to create the shape for the supply curves in that year. POLYSYS optimizes U.S. agricultural land-use patterns, iteratively solves for each of the corresponding prices, and returns that information to the RFM. This dynamic process results in a set of regional and annual supply curves, and is repeated in the first iteration for each year of each cycle.

- **Federal and non-federal forestry** – Forestry feedstocks comprise two separate supply curves, harvested from federal and non-federal forest lands. Oak Ridge National Laboratory (ORNL) provided the supply curves based on inputs from the United States Forest Service and additional analysis in ORNL's "Billion-Ton Update."[19]. The supply curves include sustainably-produced forest feedstocks, including logging residues and thinnings, other removal residues, and some use of pulpwood competitive against the paper industry. They generally exclude roundwood, or logs used for lumber products. The data is used in EIA's WODSUPP file as input to NEMS, and is not modified endogenously. The totals from public and private forestry categories are separated within NEMS since only residues from private lands are able to meet the Federal Renewable Fuels Standard.

- **Urban wood waste and mill residues** – Supply curve data for this feedstock are based on data provided by ORNL as a part of the Billion-Ton Update. Consumption data across all sectors of urban wood were provided to ORNL by independent reports (McKeever, 1998 and 2004) and mill residues were provided to ORNL from the U.S. Forestry Service's TPO Database Retrieval System. The initial urban wood and wood waste data is included in the WODSUPP file as

---

[19] Perlack, R.D. and Stokes, B.J. (Leads), Oak Ridge National Laboratory, U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry, Oak Ridge, TN 227p. U.S. Department of Energy, ORNL/TM-2011/224.2011, http://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf .

regional supply curves for each of the 16 coal demand regions, but is modified through an interaction with the industrial demand module.

The industrial module of NEMS models the captive biomass market, and projected quantities of leftover biomass not used in the industrial process or for onsite generation are passed from the industrial model to the RFM as eligible fuel for electric power plants. Historical data were used to establish how much biomass was consumed directly by the paper and wood industries as a proportion of biomass consumed across all sectors. Historical data indicates that approximately 2/3 of waste consumption is in paper and wood industries, and since industrial use of biomass consists primarily of paper and wood industries, the remaining 1/3 of waste consumption gets passed along to the RFM as urban wood waste. The WODSUPP file already includes a portion of the biomass waste consumption, so as to prevent double-counting, the WODSUPP file incorporates only one-half of the consumption passed to the RFM from the IDM.

6. Geothermal Electricity Submodule

Model purpose

The geothermal electricity submodule (GES) provides the projected supply of new geothermal generating capacity and its related average cost and performance characteristics to the Electricity Capacity Planning (ECP) submodule of the Electricity Market Module (EMM) in the National Energy Modeling System (NEMS). The supply, costs, and performance characteristics are based on information for resources at known U.S. geothermal sites as well as those classified as having near-term Enhanced Geothermal System (EGS) potential, which is an indication that the heat potential is there but additional fluids need to be injected for electricity production.

The supply available for future capacity is reduced as geothermal resources are used. These estimates include already chosen capacity identified from historical data reported to EIA, reported plans of future geothermal capacity, or resources already chosen in earlier estimations by the ECP.

Capacity (in megawatts) that can be built at any site in a specific year (annual build bounds) is limited to accurately represent industry practice of gradual expansion at geothermal sites; bounds may be modified by individual site by year. A maximum of 50 megawatts is allowed by the GES to be built at each site annually. This maximum reflects industry trends of relatively small power plant construction within the last several years.

Projected capital cost is reduced over time to reflect experience (learning-by-doing) and is increased as warranted to reflect increases in demand (short-term cost elasticities of supply). The model permits changes in the estimates of capital costs of specific sites by individual year (capital cost multipliers), enabling the GES to represent geothermal capital cost assumptions that are different from the reference case. The capital cost multipliers are numeric weights affecting the total base capital cost of each of the traditional hydrothermal and near-field EGS sites. The cost multipliers can be less than, equal to, or greater than 1.00. The design allows different weights for different sites and different weights for different years for each site.

Relationship of the Geothermal Electricity Submodule to other models

The GES interacts primarily with the ECP, providing new capacity availability, performance, and cost information to inform projected planning decisions. The GES also receives feedback on new capacity build decisions from the ECP to decrement available new geothermal resources and capacity. The GES uses financial parameters and tax data for calculations related to the competing geothermal resource sites and ECP-based avoided costs to determine the highest cost at which new geothermal supply can compete, setting the upper-cost bound of geothermal supply.

Modeling rationale

The GES develops estimates of regional geothermal capacity supplies (megawatts available in increasing order of cost per kilowatthour) used in competing geothermal technologies with fossil, nuclear, and other renewable energy generating alternatives. The estimates are developed for each forecast year and region needing new generating capacity. The model assumes that the only cost-effective and accessible geothermal resources available during the forecast period are the 125 water-based (hydrothermal)

resources and the corresponding 125 areas of near-field EGS potential in three Western EMM regions: Western Electricity Coordinating Council's Southwest (Region 19), California (Region 20), and Northwest Power Pool (Region 21). The near-field EGS potential was included for the first time in AEO2011, since NREL has been able to quantify the costs of this technology in a credible manner. Unidentified hydrothermal sites, unidentified EGS sites, and deep EGS resources were not included in the EIA geothermal supply curve, due to high uncertainties in both capital cost and capacity estimates.

Each geothermal site is characterized by a capital cost estimate, potential capacity available, capacity factor, heat rate, and operation and maintenance costs. Within each region for each model iteration in each projection year, the GES subtracts resources already used, sorts all geothermal supply segments in increasing cost order, determines from the EMM the maximum price (avoided cost) likely to be competitive, and then provides the EMM a geothermal supply projection in the form of three levelized cost-quantity pairs of available capacity that compete with other technologies.

Fundamental assumptions

Type of resource

The GES represents traditional hydrothermal geothermal resources, defined as large volumes of water trapped in permeable rock at depths of up to 33,000 feet and with temperatures above 110° C. These sites, which were largely identified by the U.S. Geological Survey (USGS) in their 2008 report, also contain dry, high-temperature areas that could be utilized with EGS development. Because development estimated costs of these EGS systems have become available in recent years, these near-field EGS areas were included in the GES for the first time in 2011. Cost estimates are based on NREL data and rely heavily on the Geothermal Electricity Technology Evaluation Model (GETEM) provided by Idaho National Laboratory. GETEM uses information such as well temperature, depth, and fluid characteristics to calculate a cost estimate for each resource.

Estimates of resources and development costs

Beginning with AEO2011, EIA has been using a new source to model the geothermal energy supply curves used in NEMS. Previously EIA had used data from DynCorp based on a 1992 work by Sandia National Laboratory. These estimates elaborated on the USGS Circular 790, which was published in 1978. Through the years, EIA determined that the projects had become overly optimistic and began decreasing supply estimates without new information from comprehensive studies. To update its geothermal supply curves more consistently, EIA obtained data in 2007 from two studies: New Geothermal Site Identification and Qualification published by California Energy Commission in 2004, and Geothermal Task Force Report published by Western Governors' Association in 2006. Both of these studies represented updated geothermal capacity and cost data, which EIA used until 2011 when additional studies from NREL and the U.S. Department of Energy's Geothermal Program Office became available. Unlike the two previous studies used, the NREL study estimates the costs and available capacity from known and unknown hydrothermal resources, near-field EGS resources, and deep EGS resources. Since the AEO is a long-term energy outlook and having accurate cost input data is a priority in the estimation, EIA includes only the 125 known hydrothermal sites with temperatures above 110° C and their corresponding near-field EGS potential areas in the EIA supply curve. This decision will be revisited as additional cost and capacity estimates become available.

NREL's geothermal report included data based on the USGS' 2008 geothermal resource assessment, in which hydrothermal potential was examined and evaluated. NREL included only 125 of the original 241 areas as likely to be developed using existing hydrothermal technology. Each of the sites has a temperature greater than 110° C and a resource depth ranging from 1,000 to 33,000 feet. USGS and NREL have estimated 6,400 megawatts of exploitable capacity potential at these sites. The estimates from NREL then used the USGS estimates and input the characteristics into the GETEM model to calculate the capital costs of exploiting each resource potential area. The near-field EGS potential was also estimated using the USGS report data along with NREL analysis.

The most recent capital cost estimates are based on EIA's *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* (2013) report, with additional information. In the report the cost estimate was based on the Salton Sea resource, which was then integrated into the supply curves. No additional sites were taken into consideration in the cost basis. Since geothermal resource areas possess wide-ranging, site-specific characterizations (not only in their temperatures, and depths but also the quality of the fluids in the ground), the cost estimate for Salton Sea in the report could not be generalized towards other sites. Therefore, the site-specific cost estimate analyzed by NREL was used instead of the cost estimate provided in the report.

Existing capacity and retirements

Existing capacity data is provided by the plant file of generating units, indicating all U.S. utility and nonutility generating units as reported on Form EIA-860, Annual Electric Generator Report. The capacity data is provided by facility name, on-line date, plant size, state, region, heat rate, and capacity factor. Starting with AEO2001, EIA no longer independently assumes retirement dates for geothermal power plants at the end of a 40-year service life. Instead, retirements are imposed when a Form EIA-860 response or other independent information externally establishes the actual or planned retirement.

Heat rates

The energy in geothermal resources varies significantly from site to site. Furthermore, differing measurement techniques can yield dramatically different heat rates. For example, heat rates can reflect the gross heat energy of the geothermal fluid at the surface or account for only the energy used at some later stage in the fluid's application. EIA has adopted the convention of using the average heat rate for fossil-fueled generators to represent the primary energy consumption of all renewable generation sources that do not require the combustion of a fuel, including geothermal. The heat rate for geothermal generating plants is currently set at the heat rate for fossil-fueled steam-electric plants of 9,716 British thermal units (Btu) per kilowatthour.

Conversion technologies

Two geothermal energy generating technologies are represented in GES: dual-flash and binary.

The lower-cost dual-flash technology converts high-temperature fluids (greater than 200° C) to steam by "flashing" the liquid to steam at two different stages. The steam is then used to drive a conventional turbine generator. The remaining liquid portion of the geothermal fluid is reinjected into the ground. Generally higher-cost binary technologies circulate the lower-temperature geothermal fluid through a closed-loop system in which the fluid heats and vaporizes a second fluid with a low boiling point, such as isopentane. The vapor of the second fluid drives the turbine generator and the low-temperature geothermal fluid is reinjected into the ground.

"Dry" steam resources, an additional geothermal technology that generates electricity solely with the use of steam, are extremely rare and therefore not represented in the GES submodule.

Capacity factors

The GES assumes a 90% capacity factor for new dual flash plants and 95% for new binary cycle plants.

Geothermal Electricity Submodule structure

The GES "SUBROUTINE GEO2000"has five basic components:

1. **Incorporates data:** On its initial iteration, subroutine "GET-SITE-DATA" reads the data from the "WGESITE" input data file characterizing the 250 U.S. geothermal sites, including capacity, cost components, operations and maintenance (O&M) costs, capacity factor, heat rate, and annual capital cost multipliers and build bounds. Subroutine "GET_PARM_DATA" reads geothermal parameters from the "WGEPARM" file. Together the two subroutines build the "GEOSITE" geothermal data structure. Capital costs are the sum of estimates for exploration, confirmation, power plant costs, and transmission costs. Annual fixed O&M costs include pump and field plus power plant costs. As geothermal energy does not require the use of a fuel, the GES submodule does not include a fuel charge. The annual capital cost multipliers are applied to the capital costs within the "GET-SITE-DATA" subroutine. The cost multipliers generally have a value of 1.00 for base cases and values <1.00 for alternate scenarios including the low renewable technology cost case. Sites in Hawaii are not used in the modeling, leaving only sites in the three Western regions (19, 20, and 21) contributing to geothermal supply.

2. **Develops overall regional geothermal supplies:** In each iteration, subroutine "BUILD-GEO-CURVES" first creates regional geothermal supply data for each of the three Western EMM regions with geothermal resources, using the 250 sites' data. The subroutine distributes each site's total available capacity (megawatts) among two increasing capital cost subgroups. The subroutine then arrays all sites' quantity-cost subgroups in each EMM region from least- to highest-cost, resulting in an aggregate regional geothermal supply array "GEOCRV." The total available capacity for each site is limited to the annual build bound for the site.

3. **Provides sub-supplies for specific regional demands:** For each iteration of the EMM, the GES estimates a maximum levelized cost (avoided cost) at which geothermal supply in each of the

regions will be able to compete. The maximum value is (1) the levelized cost of the highest-cost technology actually selected in the immediately prior iteration of the ECP plus (2) an additional percentage representing the market sharing algorithm.[20] As a result, all remaining geothermal capacity able to generate approximately at or below the previous iteration's highest cost selection, plus the market sharing tolerance, is offered as new geothermal supply in the current iteration. Subroutine "BUILD-GEO-CURVES" selects from each aggregate regional supply "GEOCRV" only that unused supply available at or below the adjusted avoided cost, and then distributes it among three increasing-cost geothermal cost-quantity pairs using capacity-weighted average per kilowatthour costs. The EMM therefore receives, for each region, three quantities of available geothermal capacity at three (increasing) levelized costs, as well as an overall (over all three steps) capacity-weighted heat rate, O&M costs, and carbon dioxide and hydrogen sulfide emissions rates. The least-cost group includes all unused capacity in the least-cost price quartile (capacity whose levelized cost is equal to or less than 25% of the cost difference between the least cost available unit and the ECP-avoided cost; the resulting quantity is not the least-cost 25% of unused capacity, but all unused capacity in the first 25% of the cost range). The second group includes all capacity between the 25th and the 75th price percentile; and the third group includes all remaining highest cost capacity. All available capacity in each cost group is then passed on to the EMM as available supply, with one levelized cost associated with each group. The one levelized cost transmitted for each group is equal to the capacity-weighted levelized average cost for the individual sites' costs within the group. EIA assumes that only the least-cost capacity group is made available to the EMM.

4. **Decrements available capacity:** Within subroutine "CRV-INFO," GES reduces the projected available geothermal capacity in each region for each iteration. The geothermal capacity is reduced in response to external reports of new geothermal builds or previous selection by the EMM in earlier iterations.

5. **Provides diagnostics:** For each iteration, subroutine "WRITE-DB" provides diagnostic information on geothermal capacity and sites chosen and technology costs and performance.

   Diagnostics provided through Excel output file "geo_out.xls" include the following:

   Geo_Input_Data displaying quantities of capacity available at each of 250 U.S. geothermal sites, including capacity in each of four potential cost categories (currently only two are used);

   Geo_Curve_Data displaying each geothermal subsite's available geothermal capacity and estimated cost per kilowatthour in least-to-highest cost order;

---

[20] The market sharing algorithm exists in recognition that in real markets technologies that are "close" in cost to the least-cost technology will occasionally be selected for economic and other reasons not represented in the modeling. Under the sharing algorithm, the closer in cost a specific other technology is to the least-cost technology, the greater (yet small) share of the available market will be taken by that technology.

Geo_Curve_Info displaying aggregate geothermal supplies and average cost per kilowatthour as available to each of four NEMS regions for each forecast year. The values are transmitted to the Electricity Market Module (EMM) as aggregate geothermal supply;

Geo_Builds displaying quantities of geothermal capacity built in each of the three NEMS regions in each forecast year.

Key computations and equations

This section describes the most important equations in the GES.

Reading the Data

In the first iteration, data for geothermal sites are read from a file **WGESITE** by the GES Subroutine GET_SITE_ DATA into the **GEOSITE** data structure. Subroutine **GET_PARM_DATA** reads the geothermal parameters from the parameter file **WGEPARM**.

GEOSITE Data Structure:

SITE_ID	
EIA_ID	
NAME	= Site Name
STATE	
AVAIL_SUPPLY	= Potential capacity -1990 capacity
CAP_COST _ADJ	= Drilling + Field + Plant Costs adjusted by capital cost multiplier (1987$/kW)
CAP_COST	= Drilling + Field + Plant costs
CAPACITY_1990	= Installed capacity 1990 (not currently used)
CAPACITY_FACTOR	= 0.00 to 1.00 (0.90 assumed for all plants)
CAPCOST_MULT	= Annual Capital Cost Multiplier for Site (Fraction)
CENSUS	= Census region of site
CO2_RATE	= Lbs. per megawatthour
COE	= 4 levelized costs, (1987$) mills per kilowatthour
DRILL_CAP_COST	= Per kilowatt capital cost component (1987$)
DRILL_CAP_COST _ADJ	= Capital cost component adjusted by capital cost multiplier (1987$/kW)
EXPLOR_CAP_COST	= Per kilowatt capital cost component (1987$)
EXPLOR_CAP_COST_ADJ	= Capital cost component adjusted by capital cost multiplier (1987$/kW)
FIELD_CAP_COST	= Per kilowatt capital cost component (1987$)
FIELD_CAP_COST _ADJ	= Capital cost component adjusted by capital cost multiplier (1987$/kW)
FIELD_OM-COST	= Per kilowatt annual field O&M cost component (1987$)
H2S_RATE	= Lbs. per megawatthour
HEAT_RATE	= Btu per kilowatthour
NERC	= NERC region of site
PFILE_EXCAP	= Existing capacity (from EMM plant file)
PLANT_CAP_COST _ADJ	= Capital cost component adjusted by capital cost multiplier (1987$/kW)
PLANT_CAP_COST	= Per kilowatt capital cost component (1987$)

PLANT_OM-COST	=	Per kilowatt annual plant O&M cost component (1987$)
POTENTIAL_CAP	=	4 increasing-cost quantities of capacity at each site
SITE_BOUND	=	Annual Build Bound for Site (MW)
SUBSITEOM_COST	=	Field O&M + Plant O&M costs
TECHTYPE	=	Technology, 1- Binary; 2 – Dual Flash
TEMP	=	Temporary data structure for sorting geosites

In each iteration, the capital, fixed O&M, and levelized cost of energy for each of two increasing-cost subsites at each site are calculated. The capital costs are adjusted for learning and technological optimism. Existing capacity is subtracted from each site's available supply. Technological optimism and learning effects are estimated in subroutine ELEC_OPT in the electricity capacity planning (ECP) submodule of the EMM.

Building regional geothermal supplies

In each iteration, projected available geothermal supplies at each site are merged with costs from other sites in the region and arrayed for competition in the ECP in each region. The GES submodule first constructs a complete array of increasing levelized cost/quantity pairs as the cumulative geothermal supply available for the region. The GES then segments the competitive part of that array into three generalized increasing cost segments, passing the total capacity available in each increasing cost segment to the ECP along with the capacity-weighted average cost of energy (mills per kilowatthour) for the capacity in the segment.

In each iteration, the GES receives a maximum cost for each region from the EMM. This maximum cost is equal to the cost of electricity of the highest cost capacity previously selected in each region, called the Regional Avoided Cost, plus the market-sharing tolerance. The avoided cost is defined as follows:

Avoided Cost = (Regional Maximum Prior COE) * (1.0 + Market Sharing Tolerance)

The subroutine "**BUILD_GEO_CURVES** iterates within each region until the capacity available in the first (lowest cost) step is greater than zero or until 10 iterations have occurred. The threshold cost is incremented 10% for each iteration.

The subroutine **ECPLVCST** develops levelized cost groups for submission to the ECP. The levelized cost groups are defined as follows:

AVAIL_SUPPLY	=	Megawatts available for each record
CUM_SUPPLY	=	Cumulative sum available megawatts in each region
SYS_CAP_COST	=	Cumulative capacity-weighted capital cost, 3 segments
SYS_CAP_FAC	=	Cumulative capacity-weighted capacity factor, 3 segments
SYS_CO2_RATE	=	Cumulative capacity-weighted CO_2 emissions rate, 3 segments
SYS_COST	=	Cumulative capacity-weighted COE, 3 segments
SYS_HEAT_RATE	=	Cumulative capacity-weighted heat rate, 3 segments
SYS_OM_COST	=	Cumulative capacity-weighted O&M cost, 3 segments

The subroutine BUILD_GEO_CURVES then determines the value for each variable for each of the 3 segments of available geothermal supply in each region. These values are derived from the cumulative values output from the ECPLVCST subroutine described above.

CAP_COST   = Capital cost
CAP_FAC   = Capacity factor
CO2_RATE   = CO_2 emissions rate
HEAT_RATE   = Heat rate
OM_COST   = O&M cost

In fact, the GES passes the ECP actual values only for the first of the three segments; values for steps 2 and 3 are expressed as weights applicable to the values in the first segment.

EMM_CAP_COST
EMM_CAP_FAC
EMM_CAPACITY
EMM_CO2_RATE
EMM_HEAT_RATE
EMM_OM_COST

$$\textbf{Average\_Capital\_Cost} = \left(\sum_{i=1}^{n} (Cap\_Cost_{(i)} * Capacity_{(i)}) \right) / \text{Cumulative\_Capacity}$$

$$\textbf{Average\_O\&M\_Cost} = \left(\sum_{i=1}^{n} (O\&M\_Cost_{(i)} * Capacity_{(i)}) \right) / \text{Cumulative\_Capacity}$$

Other features of the Geothermal Submodule

Regional Labor Cost Weights: Because the capital costs for geothermal sites are already specific to individual sites, regional labor cost weights in the EMM are set to 1.00 for all geothermal sites.

Federal Tax Credit: The Energy Policy Act of 1992 (EPACT92) has authorized for a permanent investment tax credit (ITC) of 10% to all geothermal capital costs for all projection years. Since 2004, geothermal technology is also eligible to receive production tax credit (PTC) in lieu of ITC. Projects that began construction and are beyond the exploratory drilling phase by that date are eligible for this PTC.

Land Costs: Lands used for geothermal well fields can be either purchased and accounted for in the capital costs of the project or be leased and therefore included in the project's fixed operation and maintenance costs.

Construction Lead Time, Construction Cost Profile, and First On-Line Year: In the GES, new geothermal plants are constructed over a four-year time period with most capital costs allocate to the last two years in the annual proportions of 15%, 15%, 35%, and 35%.

Learning, Short-Term Elasticities, and Technological Optimism: Capital Costs for geothermal generating technologies are affected by learning-by-doing and technological optimism. For a description of these

characteristics and assumptions and values assigned geothermal, see *Assumptions for the Annual Energy Outlook*, "Learning Parameters for New Generating Technology Components."

Appendix 6-A: Inventory of Variables, Data and Parameters

Values for this inventory are included in the body of this chapter, along with the Excel files supporting the geothermal submodule. Questions about the submodule can be directed to the official model representative listed in Appendix 6-D.

Appendix 6-B: Mathematical Description

The Geothermal submodule computes the levelized cost of energy for four increasing-cost subsites at each geothermal site, with capital costs adjusted for learning and technological optimism. The rationale and cost differentials for these four subsites are explained in the "Estimates of Resources" section in the "Fundamental Assumptions" portion of this documentation.

$$COE_{i,1,y,r} = \frac{\left[\left(DCST_{i,y} + FCST_{i,y} + ECST_{i,y} + PLNTCST_{i,y}\right) \times FCF_r \times LFACT_y \times OPFACT_y\right] + FOM_i + POM_i}{CF_i \times 8760 \times 1000}$$

$$COE_{i,2,y,r} = \frac{\left[\left(1.33 \times (DCST_{i,y} + FSCT_{i,y}) + ECST_{i,y} + PLNTCST_{i,y}\right) \times FCF_r \times LFACT_y \times OPFACT_y\right] + FOM_i + POM_i}{CF_i \times 8760 \times 1000}$$

$$COE_{i,3,y,r} = \frac{\left[\left(DCST_{i,y} + FCST_{i,y} + 2 \times ECST_{i,y} + PLNTCST_{i,y}\right) \times FCF_r \times LFACT_y \times OPFACT_y\right] + FOM_i + POM_i}{CF_i \times 8760 \times 1000}$$

$$COE_{i,4,y,r} = \frac{\left[\left(1.33 \times (DCST_{i,y} + FSCT_{i,y}) + 2 \times ECST_{i,y} + PLNTCST_{i,y}\right) \times FCF_r \times LFACT_y \times OPFACT_y\right] + FOM_i + POM_i}{CF_i \times 8760 \times 1000}$$

where

i = Geothermal Site i

y = Current Year

r = NEMS Region

$COE_{i,1,y,r}$ = Levelized Cost of energy for subsite 1 for geothermal site i.

$COE_{i,2,y,r}$ = Levelized Cost of energy for subsite 2 for geothermal site i.

$COE_{i,3,y,r}$ = Levelized Cost of energy for subsite 3 for geothermal site i.

$COE_{i,4,y,r}$ = Levelized Cost of energy for subsite 4 for geothermal site i.

$DCST_{i,y}$ = Drilling component of capital costs for geothermal site i in year y, $/kW.

$ECST_{i,y}$ = Exploration component of capital costs for geothermal site i in year y, $/kW.

$FCST_{i,y}$ = Field component of capital costs for geothermal site i in year y, $/kW.

$PLNCST_{i,y}$ = Plant component of capital costs for geothermal site i in year y, $/kW.

FCF_r = Fixed Charge Factor in EMM region r for geothermal technology, fraction.

$LFACT_y$ = Learning Factor for geothermal technology in year y, fraction.

$OPFACT_y$ = Technological Optimism Factor for geothermal technology in year y,

FOM_i = Field component of fixed O&M costs for geothermal site i, $/kW.

POM_i = Plant component of fixed O&M costs for geothermal site i, $/kW.

CF_i = Capacity Factor for geothermal site i, fraction.

The levelized costs by geothermal site and subsite are then sorted from least to highest cost, resulting in an aggregate regional geothermal supply array. These regional supply arrays are then used to generate the three-step EMM supply curves. It should be noted that while the model still incorporates the structure to break down the total capital costs into discrete components, this capability is no longer

used, because the data from which EIA gathers its estimates do not have separate cost estimates for each of these categories.

Appendix 6-C: Bibliography

Augustine, Chad and Young, Katherine. "Updated U.S. Geothermal Supply Curve," National Renewable Energy Laboratory, February 2010.

California Energy Commission, Public Interest Energy Research, prepared by GeothermEx, "New Geothermal Site Identification and qualification," April 2004.

California Energy Commission, contract report 500-89-001 prepared by Regional Economic Research, Inc., "Technical Potential of Alternative Technologies, Final Report," San Diego, CA, December, 1991, Chapter X, "Liquid-Dominated Geothermal Technical Potential."

Cassel, Thomas A.V.; Edelstein, Robert H.; Blair, Peter D.; Amundsen, Chris B., Technecon Analytic Research, Inc., final report DOE/RA/4713-1 for the U.S. Department of Energy, Assistant Secretary for Resource Application, under contract ET-78-S-02-4713A001 "Geothermal Investment and Policy Analysis With Evaluation of California and Utah Resource Areas," Philadelphia, PA, October, 1979.

DynCorp I&ET, "Geothermal Supply and Cost Performance Characteristics," contract deliverable for Purchase Order #36727 for the U.S. Energy Information Administration, Coal and Electric Power Division, Office of Integrated Analysis and Forecasting, June 30, 2000.

Electric Power Research Institute, EPRI TR-106223, prepared by CE Holt Company, project 3657-01, "Next Generation Geothermal Power Plants," Pasadena, CA, February, 1996.

Entingh, D. and McLarty, L, "Geothermal Cost of Power Model IM-GEO Version 3.05: User's Manual," February 22, 1989.

Entingh, Daniel, Princeton Energy Resources, International LLC, under task 9846-004 for the U.S. Department of Energy and National Renewable Energy Laboratory, Working Paper (draft), "Improvements in Geothermal Electric Modeling in the DOE/EIA National Energy Modeling System (NEMS), Volume 2F, Status at Start of May 2000," Rockville, MD, May, 2000.

Muffler, L.P.J., editor, "Assessment of Geothermal Resources of the United States – 1978," U.S. Geological Survey Circular 790, 1978.

Northwest Power Planning Council, "Northwest Power in Transition, Opportunities and Risks; Draft Fourth Northwest Conservation and Electric Power Plan," Portland, OR, March, 1996, Appendix FGT, "Geothermal."

Petty, Susan; Livesay, B.J; Long, William P.; Geyer, John, Sandia National Laboratory, Contractor Report SAND92-7302 "Supply of Geothermal Power from Hydrothermal Sources: A Study of the Cost of Power in 20 and 40 Years," Albuquerque, New Mexico, November 1992.

Petty, Susan, Susan Petty Consulting; Livesay, Bill, Livesay Consultants, Inc., prepared for National Renewable Energy Laboratory, "Database of Hydrothermal Sites in the U.S. With Potential for Electric Power Generation," March, 1993.

U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, April 2013.

Western Governors' Association, "Geothermal Task Force Report: Clean and Diversified energy Initiative," January 2006.

Appendix 6-D: Model Abstract

Model name:
Geothermal Electric Submodule

Model acronym:
GES

Description:
The GES projects regional geothermal capacity supplies and cost and performance characteristics used in competing geothermal technologies with fossil, nuclear, and other renewable electricity generating alternatives for each forecast year and region needing new generating capacity in the EMM. Regional geothermal supplies are based on each region's share of geothermal resources estimated for 250 identified U.S. geothermal sites, with (1) capital cost estimates for each geothermal site, (2) two-step low-to-high cost estimates of the number of megawatts of capacity available at select site, (3) assumptions for increasing capital costs for increasing portions of the high estimates for each site, and (4) capacity factors, fixed operation and maintenance costs, heat rates, and CO_2 emissions rates for each site. Within each region for each model iteration in each forecast year, the GES decrements already chosen resources, arrays all unused geothermal supply in increasing cost order, determines from the EMM the maximum price (avoided cost) likely to be competitive in the EMM, and then provides the EMM three increasing levelized cost-quantity pairs of available capacity in each region for use in competition with other technologies.

Purpose of the model:
The purpose of the GES is to provide the Electricity Capacity Planning module (ECP) the projected amounts of available geothermal generating capacity and its cost and performance characteristics for competition in the ECP for new regional electricity supply in the western United States.

Most recent model update:
March 2016.

Part of another model?:
The GES submodule is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

Official model representative:
Chris Namovicz
Renewable Electricity Analysis Team,
Office of Electricity, Coal, Nuclear and Renewables Analysis
U.S. Energy Information Administration, EI-34
1000 Independence Ave., SW
Washington, DC 20585
Phone: (202) 586-7120
e-mail: chris.namovicz@eia.gov

Documentation:

This chapter constitutes the documentation of the GES.

Archive media and installation manual(s):

The GES is archived as part of the NEMS production runs.

Energy system described:

Hydrothermal geothermal and near-field EGS energy resources of the western United States and the costs and performance characteristics of the technologies converting them to electricity supply.

Coverage:

- Geographic: EMM regions 19, 20, and 21.
- Time Unit/Frequency: Annual through 2040.
- Products: Electricity
- Economic Sectors: Electricity Generators

Modeling features:

- Modeling Structure: The model operates at the level of individual geothermal sites aggregated to segmented EMM regional averages.
- Model Technique: Levelized electricity costs from each supply segment of each site in each region are arrayed in increasing cost order, then aggregated into three increasing average-cost segments in each iteration in each year, along with attendant quantities (megawatts) and average heat rates and capacity factors.
- Incorporates short-term cost elasticities of supply, technological optimism, and learning.

Independent expert reviews conducted:

None. However, during development of the submodule ongoing review and comment were obtained from the DOE Office of Energy Efficiency and Renewable Energy, Office of Power Technologies, the National Renewable Energy Laboratory, and from DynCorp Corporation, among others. See Appendix 6-C: Bibliography, above.

Status of evaluation efforts by sponsor:

None.

7. Conventional Hydroelectricity Submodule

Model purpose

The Conventional Hydroelectricity Submodule (CHS) represents U.S. conventional hydroelectricity ("hydro") resources supply along with each site's technology cost and performance characteristics used to project new conventional hydroelectric capacity for central station electricity supply through the mid-term future. More specifically, the CHS does the following:

- Provides the Electricity Market Module (EMM) Electricity Capacity Planning (ECP) submodule the available supply (megawatts) of new conventional hydroelectric generating capacity 1 megawatt or greater (and not more than 10 cents per kilowatthour) as well as its related average cost and performance characteristics based on information about known conventional hydroelectric sites.
- Reduces supply available for additional future capacity as conventional hydroelectric capacity resources are used, including capacity identified from historical data, from reported plans, and from resources already chosen in earlier forecasting iterations by the ECP.
- Adjusts estimated levelized costs of hydroelectricity from each site based on its public acceptance and the probability of meeting environmental requirements (environmental suitability factor).
- Changes average calculated hydroelectric capital costs, reducing them to reflect experience (learning-by-doing); short-term elasticities are not applied for conventional hydroelectric.
- Permits changes in the assumed hydroelectric capital costs for use in alternative cases through the use of capital-cost coefficients by (a) individual site or (b) for all sites in a specific year(s).

Identification of sites and costs for use in the CHS was originally estimated by the Idaho National Engineering and Environmental Laboratory from lists assembled from Federal Energy Regulatory Commission license applications and other survey information.[21] However, starting with *AEO2006*, EIA staff eliminated the representation of some large sites found by inquiry to no longer exist and, for retained sites 100 megawatts or greater, replaced generalized site capacity factors with individual site capacity factors estimated by the Federal Energy Regulatory Commission.

Relationship of the Conventional Hydroelectricity Submodule to Other Models
The CHS interacts primarily with the ECP. Relationships between the CHS and other NEMS components include

- CHS provides new capacity availability, performance, and cost information to the ECP for making planning decisions.
- CHS uses new capacity build decisions from the ECP to decrement available new conventional resources and capacity.

---

[21] 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).

- CHS uses financial parameters and tax data for calculating ECP-based avoided costs to determine the highest cost at which new hydro supply can compete, setting the upper-cost bound of hydro supply.

Modeling rationale

For each NEMS region, the Conventional Hydroelectricity Submodule develops three-part estimates of regional conventional hydroelectric supplies – total megawatts available in order of three increasing-cost price and quantity pairs. These are used to compete conventional hydroelectric technologies with fossil, nuclear, and other central-station Renewable Electricity generating alternatives, for each forecast year and region needing new generating capacity.

Fundamental assumptions

In the underlying hydro resource database, each named hydroelectric site is characterized by its name, location, ownership, resource, cost, and performance characteristics, notably including its (a) components of capital cost, (b) average monthly and annual capacity factors, (c) fixed and variable operating costs, and (d) estimated probability of meeting legal, cultural, and environmental barriers, plus additional identifying information. For each model iteration within each forecast year and region, the CHS arrays all available hydro sites from least to highest cost at or below the avoided cost (plus an additional percentage to account for market-sharing, that is, to accept some capacity that is "close" to competitive) determined in the previous model iteration (an estimate of the upper bound of likely acceptable cost in the current iteration). The CHS then segments the array into three parts—a least-cost, middle, and upper-cost segment—and determines the capacity-weighted average (a) capital cost, (b) operations and maintenance costs, and (c) capacity factors for each group, and then provides the EMM a conventional hydroelectric supply in the form of three increasing levelized cost-quantity pairs of available hydroelectric capacity.

A significant submodule tool enables the analyst to adjust the CHS to influence forecasts of new hydroelectric capacity by adjusting the proportions of the overall cost range attributed to each segment. A downward adjustment to the proportion of the array (share of the overall range of cost) characterized in the lowest-cost segment, for example, would lower both the average cost of the first segment— thereby increasing the probability of being selected—but relatively decreasing the quantity of capacity likely to be selected. Increasing the proportion of the overall cost range in a segment increases the amount of capacity available in that range but also increases the average capital cost of the capacity as a consequence. Moreover, because each of the three segments characterizes an average, decisions regarding proportions also influence the magnitude of the increase in cost between steps, with large proportions yielding large cost increases and small steps yielding small average increases.

Input data for the supplies were initially provided by the Idaho National Engineering and Environmental Laboratory (INEEL) under a project jointly funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy and the U.S. Energy Information Administration.[22] The effort is described in *Estimation of Economic Parameters of U.S. Hydropower Resources* INEEL/EXT-03-00662 (Idaho Falls, Idaho, June 2003). The original database, named IHRED, "Idaho Hydropower Resource

---

[22] Contract DE-AC007-99ID13727, completed June, 2003.

Economics Database," is available through INEEL or EIA as an appendix to the report. The INEEL database, moreover, represents an initial effort in assigning cost attributes to an already-developed site database, the "Hydropower Evaluation Software" (HES) database, based on (1) The Federal Energy Regulatory Commission's Hydropower Resource Assessment database developed from hydropower licensing actions, (2) the Nationwide Rivers Inventory Database developed and maintained by the National Park Service, and (3) supporting information from state resource and energy agencies.[23] The more recent INEEL IHRED effort supplemented the HES by providing generalized estimates of capital and other costs, as well as generalized (regional) estimates of capacity factors. Costs and other monetary values in IHRED are expressed in 2002 dollars (NEMS expresses these same values in 1987 dollars).

For *AEO2006* and subsequent reports, EIA modified the IHRED in the following ways: First, HES-estimated capacity factors specific to each hydro site replaced the regional generalized estimates from IHRE. In general, the site-specific estimated capacity factors are lower than the IHRED factors but are considered superior, based on specific assessments of the sites. Second, to reduce workload, EIA eliminated from consideration all sites for which an offline estimate of the levelized cost of generation exceeded 10 cents per kilowatthour (2002 dollars), given the near impossibility of any such site being selected in any conceivable scenario. Third, the IHRED database was separated into two groups, "small" sites, 100 megawatts or less, and "large" sites, greater than 100 megawatts; data on all "small sites" were accepted for use. Finally, large sites were arrayed from least to highest cost and then individually reviewed, to the extent permitted by time and resources, contacting site owners or state agencies to verify the existence and viability of such sites. Many large sites were found unavailable (already developed, otherwise developed, now precluded by Wild and Scenic Rivers, or other circumstance making development naturally or legally impossible). Not all large sites were examined. Documentation of calculations and modifications can be found in the EIA-maintained Excel files "HydroLessThan10cents033004.xls" and "HydroCritiqueTop100041904.xls."

Resources

The CHS characterizes economic supply of both run-of-river and storage dams for conventional hydroelectric power at new or existing sites 1 megawatt or greater. The model incorporates data on some—though not all—potential hydroelectricity supply, including undeveloped sites with no dam, opportunities for adding hydroelectric capacity at existing dams without hydropower, and opportunities to increase capacity at existing hydroelectric facilities.

Exclusions

The CHS does not represent all hydroelectric potential. First, the CHS does not represent opportunities less than 1 megawatt capacity. Second, the CHS does not enumerate new pumped storage hydroelectricity potential, an energy storage technology using off-peak coal or nuclear-powered electricity to lift water to an upper pool for later peaking hydro generation. (Operation of existing pumped storage, however, is modeled in the EMM.) Third, the supply also omits sites excluded from development by federal statutes and policies, including hydro resources excluded by the Wild and Scenic Rivers Act (or sited at the upstream or downstream ends of wild and scenic streams or on a tributary, in

---

[23] Alison M. Conner, James E. Francfort, and Ben N. Rinehart, Idaho National Engineering and Environmental Laboratory, *U.S. Hydropower Resource Assessment, Final Report*, Contract DE-AC07-94ID13223 (Idaho Falls, Idaho, December 1998).

National Parks, or otherwise excluded by federal or state law or in a federally designated exclusion zone). Furthermore, the CHS does not represent offshore (ocean) hydro, in-stream (non-impoundment) potential, additional potential from refurbishing existing hydro capacity, or increased output opportunities from efficiency or operational improvements, any or all of which could also add to U.S. hydroelectric supply. In addition, the CHS does not represent any sites for which off-line EIA estimates made in 2004 indicated levelized per-kilowatthour costs (in 2002 dollars) greater than 10 cents per kilowatthour. EIA staff also eliminated from the supply a number of sites 100 megawatts or greater that, based on contacts with owning firms, were concluded to not be available today – with the identified resources already developed, excluded from development by law, or otherwise unable to offer additional potential today. Finally, the CHS does not account for any unknown additional conventional hydroelectric potential that might become available at known sites included in these estimates, but at costs higher than would have been competitive when FERC licenses were sought or surveys conducted – and therefore not estimated.

Capital costs

Overnight capital costs – and all other costs - are expressed in 2002 dollars. Components of overnight capital costs include licensing, construction, and a range of individual environmental mitigation costs (see below) as applicable to individual sites. Construction costs include land and rights, structures and improvements, reservoirs, dams, waterways, equipment, and access roads, rail, and bridges. Construction costs were derived by INEEL primarily from 1990-2000 FERC Form 1, *Annual Report of Major Electric Utilities, Licensees, and Others*.

Learning by doing

"Learning by Doing" refers to reductions in a technology's capital costs as experience with the technology is gained, expressed in NEMS as a function of the total amount of capacity in place. Therefore, the capital costs of conventional hydroelectric plants decrease in NEMS as additional capacity is built.

For a description of learning by doing in NEMS, see either *Assumptions for the Annual Energy Outlook or Electricity Market Module of the National Energy Modeling System, Model Documentation Report* for the relevant *Outlook* year. Conventional hydroelectricity is considered a mature technology, meaning that hydroelectricity is already well developed and that capital costs will likely decrease at the slowest rate.

NEMS also includes a minimum decrease in capital costs independent of actual builds.

Short-term elasticities

In NEMS, capital costs for most technologies are assumed to increase if capacity increases rapidly within a given year, thereby temporarily squeezing supply resources (such as skilled labor, materials, and manufacturing). More information for these elasticities can also be found in the Assumptions and Documentation reports. These short-term elasticities are not applied to conventional hydroelectricity, because U.S. and global infrastructure are currently considered fully capable of meeting all demand for the mature technology.

Mitigation costs – construction component

For sites not prohibited from development but nevertheless facing environmental mitigation requirements, the construction costs of such mitigation are individually estimated and included among capital costs derived from a variety of sources documented in the INEEL report. Individual categories of potential mitigation cost include archeological requirements, fish and wildlife protection, scenic or recreation requirements, water quality monitoring, and fish passage requirements. All are expressed in 2002 dollars per kilowatt and are included among capital costs.

Mitigation costs – public acceptance component

IHRED-estimated mitigation costs account for the "bricks and mortar" construction costs of mitigation requirements. To account for the litigation, licensing, and public acceptance costs of mitigation, EIA adapted the HES environmental "suitability factor" to estimate the probability of a hydroelectric project's successful development in light of all individual environmental characteristics of the site. Suitability factors range from 0.90 (the greatest probability of meeting environmental requirements and being developed), through 0.75, 0.50, 0.25, and finally, 0.10. The HES included no estimates of the costs of overcoming likely objections. However, EIA incorporated into its submodule an arbitrary estimate of levelized additional costs per kilowatthour, in order to represent the added costs of meeting environmental requirements – such as for legal challenges, studies, public outreach, etc. - in addition to the engineering costs already accounted:

If Site Probability = 0.90, then add   0.00 mills to levelized cost (1987$)
If Site Probability = 0.75, then add   3.00 mills to levelized cost (1987$)
If Site Probability = 0.50, then add   5.00 mills to levelized cost (1987$)
If Site Probability = 0.25, then add   8.00 mills to levelized cost (1987$)
If Site Probability = 0.10, then add 10.00 mills to levelized cost (1987$)

These cost adjustments almost certainly eliminate most of the 0.25 and 0.10 probability sites from practical consideration and greatly reduce the competitive potential of 0.50 sites as well. Changing the costs associated with site probabilities offers another opportunity for analyst influence on hydroelectric supply costs.

Fixed operation and maintenance costs

Fixed Operation and Maintenance (O&M) costs include operation and maintenance supervision and engineering, as well as maintenance of structures, reservoirs, dams, waterways, and electric plant; where applicable, fixed O&M includes the FERC annual charge noted below. Fixed O&M costs were derived from FERC Form 1 data for 1990-2001 and are expressed in 2002 dollars per kilowatt per year.

FERC annual charge

For plants with a capacity greater than 1.5 megawatts, FERC charges plant owners an annual fee based on plant capacity and annual generation. The FERC annual charge is considered part of fixed O&M and is estimated using an estimate of constant annual generation derived by INEEL, based on 1999 charges,.

Variable operation and maintenance costs

Variable O&M maintenance costs, also derived from FERC Form 1 data, include estimates for charges for water for power, hydraulic and electric expenses, miscellaneous hydraulic power expenses, and rents. Variable O&M is expressed in 2002$ mills per kilowatthour.

Capacity factors

The IHRED database contains both estimated monthly and annual capacity factors for each site. However, EIA replaced these regional average annual capacity factors with the individually determined annual capacity factors established by FERC or in other specific studies underlying the HES database; monthly IHRED capacity factors were then modified in proportion to the annual factor adjustment. In general, the individual capacity factors are lower than the generalized estimates. Moreover, EIA also applied exceptions, using the IHRED estimate or 65% (whichever was lower) for undeveloped sites for which no FERC capacity factor was available, and 35% for incremental capacity for which no FERC capacity factor was available. Where the FERC capacity factor exceeded 65% for new sites or 35% for incremental capacity, EIA assigned either 65% or 35%, given that the EIA bound, while arbitrary, is higher than the averages for known sites, and the FERC values appear to often be in error (at times exceeding 100%).

Regional adjustment factors are used in the CHS to enable modification of projected hydroelectric output on a regional level. This may be necessary for years where projected hydroelectric generation is anomalously high or low. Current regional adjustment factors are set so that the result of multiplying them by the site-specific capacity factors approaches a 20-year average.

Heat rates

Conventional hydroelectric facilities tend to be highly efficient; the Federal Energy Regulatory Commission cites modern hydroelectric turbines to be about 90% efficient (90% of input energy converted to output electricity), suggesting an average input heat rate equivalent under 3800 Btu per kilowatthour.[24] EIA has adopted a convention of using the average heat rate for fossil-fueled generators to represent the primary energy consumption of all renewable generation sources that do not require the combustion of a fuel, including hydroelectric. This is currently set at the heat rate for fossil-fueled steam-electric plants of 9,756 Btu per kilowatthour.[25]

Alternative approaches

Prior to developing the conventional hydroelectric submodule, EIA staff extensively polled hydroelectricity analysts and organizations and conducted ongoing exchanges with contacts at the National Hydropower Association, Oak Ridge National Laboratory, the Bonneville Power Administration, the Tennessee Valley Authority, and others. Although many annual and short-term regional forecasting models of expected output from existing hydroelectric capacity can be found, no models of mid- or

---

[24] Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States, Developed and Undeveloped* (Washington, D.C. January 1, 1992), page xx. Applying the 90% efficiency cited by FERC to the 3412-Btu-per-kilowatthour energy content of electricity yields an input heat rate of 3,791 input Btu per kilowatthour.

[25] See Table A6 at http://www.eia.gov/totalenergy/data/annual/#appendices .

longer-term hydroelectric supply were found, either of resources expressed in terms of economic supply or in terms of their competition with other central station electricity supplies.

Conventional Hydroelectricity Submodule structure

The CHS **SUBROUTINE HYDRO** has five basic components:

1. **Incorporates data:** On its initial iteration, subroutine **GET_HYSITE_DATA** reads the hydroelectric site data from the **HYDSITE.TXT** input data file containing records of each individual hydroelectric site, including state and NEMS region, nameplate capacity, capital and O&M cost components, and capacity factors. Subroutine **GET_HYDATA** reads in the annual capital cost multipliers, build-bounds, public acceptance mitigation costs and the supply curve cost segment ranges from the input data file, **WHYDRO.TXT**. Together the two build the **HYDSITE** conventional hydroelectric supply structure. Capital costs are the sum of licensing, construction, and environmental mitigation costs; both fixed and variable O&M costs are incorporated; there are no fuel charges for hydroelectricity, although the FERC annual charge is included, where applicable, with fixed O&M. The annual capital cost multipliers are applied to the capital costs before leaving the **GET_HYSITE_DATA** subroutine. The cost multipliers will usually have the value 1.00 for reference cases and various values less than 1.00 for alternate scenarios such as high renewables cases.

2. **Develops NEMS overall regional conventional hydroelectric supplies:** In each iteration, subroutine **BLD_HYD_CURVES** first creates NEMS regional conventional supplies for each NEMS region (Alaska and Hawaii are processed in the hydroelectric submodule but not used by the EMM). Within each NEMS region, sites are arrayed from least to greatest in order of estimated levelized cost, resulting in an aggregate conventional hydroelectric supply for each region in each iteration, in the array **HYDCURVE**.

3. **Provides sub-supplies for specific regional demands:** For each iteration of the EMM, the CHS determines the maximum levelized cost (avoided cost) at which hydroelectric supply in each region can compete. The maximum competitive value is (1) the levelized cost of the highest-cost technology actually selected in the immediately prior iteration of the ECP plus (2) an additional percentage representing the market-sharing algorithm.[26] As a result, all remaining hydroelectric capacity able to generate at or below the previous iteration's maximum competitive value is offered as new hydroelectric supply in the current iteration. Next the subroutine **BUILD_HYD_CURVES** segments each region's aggregate hydroelectric supply among three increasing-cost quantity pairs using capacity-weighted average costs per kilowatthour. This provides the EMM three quantities of available conventional hydroelectric capacity, as well as their respective O&M costs and seasonal and annual capacity factors at three increasing levelized costs for each region. The gross cost difference between the least-cost unused hydroelectric capacity and the ECP-adjusted avoided cost is used to identify the three groups. The least-cost group includes all unused capacity in the least-cost quartile (capacity whose levelized cost is equal to or less than +25% of the gross cost

---

[26] The market-sharing algorithm exists in recognition that in real markets technologies that are "close" in cost to the least-cost technology will occasionally be selected for economic and other reasons not represented in the modeling. Under the sharing algorithm, the closer in cost a specific other technology is to the least-cost technology, the greater (yet small) share of the available market will be taken by that technology.

difference). It is important to note that the quantity in this group is not the least-cost 25 percent of capacity, but whatever proportion of capacity occurs in the lowest 25 percent of the cost range. The second group includes all capacity between the 25th percentile and the 75th percentile; and the third group includes all remaining capacity above the 75th cost percentile. All available capacity in each cost group is then conveyed to the EMM as available supply, with one levelized cost associated with each group. The one levelized cost transmitted for each group equals the capacity-weighted levelized average cost for the individual sites' costs within the group. A model variable enables the analyst to vary the initial percentage thresholds. The consequence of lower thresholds is lower average costs – and greater ability to compete – but reduced quantities available to compete, whereas higher thresholds yield greater supplies but higher (and less-competitive) average costs. Recognizing that the three segments yield significant increases in average costs (discontinuities) from one step to the next, the choice of thresholds can result in significant differences in NEMS selections of conventional hydroelectric capacity, particularly if choices have the effect of limiting supply to one (or none) of the segments.

4. **Decrements available capacity:** Within subroutine **BUILD_HYD_CURVES**, for each iteration, CHS reduces available conventional hydroelectric capacity in each region in response to (a) external reports of new hydroelectric builds in the region or (b) selection by the EMM in earlier iterations.

5. **Provides diagnostics:** For each iteration, subroutine **WRITE-HYDB** provides diagnostic information on hydroelectric capacity, sites chosen, technology costs, and performance. Diagnostics provided through Excel output file **HYDRO_OUT.XLS** include the following data sets:

Hyd_Input_Data displaying quantities of capacity available at each hydroelectric site;

Hyd_Curve_Data displaying in least-to-highest cost order each hydroelectric site's capacity and estimated cost per kilowatthour;

Hyd_Curve_Info displaying aggregate conventional hydro supplies and average cost per kilowatthour as available in each NEMS region for each forecast year, values transmitted to the Electricity Market Module (EMM) as aggregate hydroelectric supply; and

Hyd_Builds displaying quantities of conventional capacity built in each NEMS region in each forecast year.

Key computations and equations

This section describes the most important equations in the CHS.

Reading the data

In the first iteration, data for the hydroelectric sites are read in from the **HYDSITE** input file by the CHS subroutine, **GET_HYSITE_DATA**. The site data are stored in the HYDSITE data structure, which is defined below. Subroutine **GET_HYDATA** reads the hydro parameters from the input file **WHYDRO**.

HYDSITE Data Structure:

PROJNAME	Project Name
PROJNUM	Project Number
STATE	State Location

SITE_ID	Site ID
NERC	EMM Region
LATITUDE	Latitude
LONGITUDE	Longitude
CLASS	Site Class Code:C=Coop, F=Federal, I=Industrial,
	M=Municipal, P=Private Utility, R=Private Non-Utility,
	N/A=Not Available
UNITTYPE	C=Conventional, R=Reversible, Z=Missing
PLNTTYPE	Plant Type
PROJSTATUS	Project Status
DAMSTATUS	Dam Status
WSPROT	Wild/Scenic Protection Y=Yes, N=No
WSTRIB	Wild/Scenic Tributary, Location Y=Yes, N=No
ENVVALUES	Environmental Values, Y=Yes, N=No
	1=Cultural Value, 2=Fish, 3=Geological, 4=Historical,
	5=Other, i.e., rare wetland, wilderness designation, 6=Recreation
	7=Scenic, 8=Wildlife, 9=Threatened/Endangered Wildlife
	10=Threatened/Endangered Fish
LANDCODES	Federal Land Codes, Y=Yes, N=No
	1=FLC103, National Park, Monument, Rec area, etc.,
	2=FLC104, National Forest or Grassland,
	3=FLC105, National Wildlife Refuge, Game Preserve, or Fish Hatchery
	4=FLC106, National Scenic Waterway or Wilderness Area
	5=FLC107, Indian Reservation
	6=FLC108, Military Reservation
	7=FLC198, Not on Federal Land
SITEPROB	Project Environmental Suitability Factor
	.10 = Development prohibited or highly unlikely
	.25 = Major reduction in likelihood of development
	.50 = Likelihood of development reduced by half
	.75 = Minor reduction in likelihood of development
	.90 = Little effect on likelihood of development
LISCCOST	Licensing Cost 2002 $K
CONSCOST	Construction Cost 2002 $K
DEVCOST	Overnight Development Cost 2002 $K
MIT_ARCH	30 Year Archaeological and Historical mitigation cost 2002 $K
MIT_FISH	30 Year Fish and Wildlife mitigation cost 2002 $K
MIT_SCEN	30 Year Scenic and Recreation mitigation cost 2002 $K
MIT_WATER	30 Year Water Quality Monitoring Cost 2002 $K
MIT_PASS	30 Year Fish Passage cost 2002 $K
MIT_TOTAL	Total mitigation cost 2002 $K
TOTDEV_COST	Total Development Costs (Mit_Total + Devcost) 2002 $K
UNITDEV_COST	Total Unit Development Costs 2002$/kW

COE	Levelized Cost 2002$/MWh
CAP_COST	Capital Cost 2002$/kW
TOTFOM_COST	Avg Annual Fixed O&M Cost 2002 $K
TOTVOM_COST	Avg Annual Variable O&M Cost 2002 $K
FOM_COST	Avg Annual Fixed O&M Unit Cost 2002$/kW
VOM_COST	Avg Annual Variable O&M Unit Cost 2002$/MWh
FERC_COST	FERC Annual Charge (Applicable if >= 1.5 MW) 2002 $K
UNITFERC_COST	FERC Annual Charge Unit Cost (Applicable if >= 1.5 MW) 2002$/KW
POTENTIAL_CAP	Potential Capacity (MW)
CAPCOST_MULT	Yearly Capital Cost Multipliers by Hydro Sites
CAP_COST_ADJ	Capital Cost Adjustment Factors
MON_CAPACITY_FACTOR(12)	0.00 TO 1.00 - monthly capacity factors
AVG_CAPACITY_FACTOR	0.00 TO 1.00 - average annual capacity factors

In each iteration, the capital, O&M, and levelized cost of energy for each site is calculated, with capital costs adjusted for learning and technological optimism. Technological optimism and learning effects are estimated in subroutine ELEC_OPT in the electricity capacity planning (ECP) submodule of the EMM.

Building regional hydroelectric supplies

In each iteration, data on supplies at each site are merged with cost data from other sites in each region and arrayed for competition in the ECP within the region. The CHS first constructs a hydroelectric supply curve of levelized cost of energy and capacity available for each EMM region. CHS then segments the competitive part of that array into three generalized increasing cost segments (as described in the Conventional Hydroelectric Submodule Structure section), passing to the ECP the total capacity available in each increasing cost segment along with the capacity-weighted cost and performance parameters for the segment.

For each region and in each iteration, the CHS receives a maximum cost from the EMM, a value equal to the COE of the highest cost capacity previously selected in each region, called the Regional Avoided Cost, plus the market-sharing tolerance. This avoided cost is used to determine the competitive part of the arrayed costs.

Avoided Cost = (Regional Maximum Prior COE) * (1.0 + Market Sharing Tolerance)

The subroutine **BUILD_HYD_CURVES** iterates within each region until the capacity available in the first (lowest-cost) step is greater than zero or 10 iterations have occurred, incrementing the threshold cost 10% for each iteration. The cumulative values calculated in this subroutine include the following:

AVAIL_SUPPLY	= Megawatts available for each record
CUM_SUPPLY	= Cumulative sum available megawatts in each region
SYS_CAP_COST	= Cumulative capacity-weighted capital cost, 3 segments
SYS_CAP_FAC	= Cumulative capacity-weighted capacity factor, 3 segments
SYS_MON_CAP_FAC	= Cumulative capacity-weighted monthly capacity factors, 3 segments
SYS_COST	= Cumulative capacity-weighted COE, 3 segments

SYS_VOM_COST   = Cumulative capacity-weighted Variable O&M cost, 3 segments
SYS_FOM_COST   = Cumulative capacity-weighted Fixed O&M cost, 3 segments

From these cumulative values **BUILD_HYD_CURVES** then determines the specific value for the cost and performance variables for each of the three segments of available hydroelectric supply in each region. The cost and performance variables calculated include the following:

CAP_COST   = Capital cost
CAP_FAC   = Capacity factor
MON_CAP_FAC   = Monthly Capacity factors
FOM_COST   = Fixed O&M Cost
VOM_COST   = Variable O&M cost

The above values are calculated as weighted averages as shown in the equations below, where i represents each individual site:

Average_Capital_Cost $= (\sum_i (CAP\_COST_{(i)} * Capacity_{(i)}))/ Cumulative\_Capacity$
Average_FOM_Cost $= (\sum_i (FOM\_COST_{(i)} * Capacity_{(i)}))/ Cumulative\_Capacity$
Average_VOM_Cost $= (\sum_i (VOM\_COST_{(i)} * Capacity_{(i)}))/ Cumulative\_Capacity$
Average_Cap Fac $= (\sum_i (CAP\_FAC_{(i)} * Capacity_{(i)}))/ Cumulative\_Capacity$
Average_Mon_Cap Fac $= (\sum_i (MON\_CAP\_FAC_{(i)} * Capacity_{(i)}))/ Cumulative\_Capacity$

The CHS passes the ECP actual values only for the first of the three segments; values for steps 2 and 3 are expressed as weights applicable to the values in the first segment. The variables passed to the EMM include the following:

EMM_CAP_COST
EMM_CAP_FAC
EMM_MON_CAP_FAC
EMM_CAPACITY
EMM_VOM_COST
EMM_FOM_COST

Other features of the Hydroelectric Submodule

Construction Lead Time, Construction Cost Profile, and First On-Line Year: In the CHS, new hydroelectric plants are constructed over a four-year time period, with capital costs allocated in the annual proportions 15%, 22%, 30%, and 33%.

Learning, Short-Term Elasticities, and Technological Optimism: Capital Costs for hydroelectric generating technologies are affected by learning-by-doing (as are all generating technologies), as well as by technological optimism. For a description of these characteristics and assumptions and values used for hydroelectric, see "Electricity Market Module" Assumptions to the Annual Energy Outlook.

Appendix 7-A: Inventory of Variables, Data and Parameters

Values for this inventory are included in the body of this chapter, along with reference to the Excel files supporting the conventional hydroelectricity submodule. Questions about the submodule can be directed to the Official Model Representative, listed in Appendix 7-D. Data files for the CHS are maintained in the Office of Electricity, Coal, Nuclear, and Renewables Analysis (OECNRA). The INEEL deliverable is also available through OECNRA.

Appendix 7-B: Mathematical Description

Questions about the CHS algorithm can be directed to the Official Model Representative, listed in Appendix 7-D. The conventional hydroelectricity submodule computes the levelized cost of energy for three increasing cost segments of conventional hydroelectric supply in each NEMS region in each NEMS iteration for each forecast year. Rationales are explained in the "Model Purpose" and "Fundamental Assumptions" portion of this documentation. The levelized cost for each site is calculated as follows:

$$COE_{i,y,r} = \frac{\left(CCST_{i,y} + LCST_{i,y} + MCST_{i,y}\right) \times FCF_r \times LFACT_y \times OPFACT_y + FOM_i + FERC_i}{CF_i \times 8760 \times 1000} + VOM_i + PUBCOST_i$$

where

i	= Hydroelectric Site
y	= Current Year
r	= NEMS Region
COE_i	= Levelized cost of energy for hydroelectric site i.
$CCST_{i,y}$	= Construction costs for hydroelectric site i in year y, \$/kW.
$LCST_{i,y}$	= Licensing costs for hydroelectric site i in year y, \$/kW.
$MCST_{i,y}$	= Total mitigation costs for hydroelectric site i in year y, \$/kW.
FCF_r	= Fixed Charge Factor in EMM region r for hydroelectric technology, fraction.
$LFACT_y$	= Learning Factor for hydroelectric technology in year y, fraction.
$OPFACT_y$	= Technological Optimism Factor for hydroelectric technology in year y, fraction.
FOM_i	= Fixed O&M costs for hydroelectric site i, \$/kW.
$FERC_i$	= FERC Annual Charge for hydroelectric site i, 1987 \$/kW.
CF_i	= Capacity Factor for hydroelectric site i, fraction.
VOM_i	= Variable O&M costs for hydroelectric site i, \$/MWh.
$PUBCOST_i$	= Public Acceptance Cost for hydroelectric site i, \$/MWh.

The levelized costs by hydroelectric site are then sorted from least to highest cost, resulting in an aggregate regional hydroelectric supply array. These regional supply arrays are then used to generate the three-step EMM supply curves.

Appendix 7-C: Bibliography

Conner, Alison M. , Francfort, James E., and Rinehart, Ben N., Idaho National Engineering and Environmental Laboratory, *U.S. Hydropower Resource Assessment*, *Final Report*, Contract DE-AC07-94ID13223 (Idaho Falls, ID, December 1998).

Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States, Developed and Undeveloped* (Washington, DC, January 1, 1992).

Hall, Douglas G., Hunt, Richard T., Reeves, Kelly S., and Carroll, Greg R., Idaho National Engineering and Environmental Laboratory, *Estimation of Economic Parameters of U.S. Hydropower Resources* INEEL/EXT-03-00662 (Idaho Falls, ID, June 2003).

Appendix 7-D: Model Abstract

Model name:
Conventional Hydroelectricity Submodule

Model acronym:
CHS

Description:
The CHS converts lists of identified available U.S. conventional hydroelectric potential and costs into three-part increasing-cost regional supply projections (quantity-cost pairs) for each NEMS region for each forecast year. Input data for each site include its state and NEMS region, components of capital cost, fixed and variable operations and maintenance costs, and capacity factors. All sites able to produce electricity at or below an avoided cost determined by NEMS in the previous forecast cycle (adjusted upward for market sharing) become eligible to compete as new hydroelectric supply averaged among one of the three increasing cost groups. After selecting some capacity, the CHS decrements the available supply for the next iteration by the amount taken in the current cycle.

Purpose of the model:
The purpose of the CHS is to provide the Electricity Capacity Planning (ECP) module the amounts of available conventional hydroelectric generating capacity, their costs, and performance characteristics for competition in the ECP for new regional electricity supply.

Most recent model update:
September 2012

Part of another model?:
The CHS submodule is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

Official model representative:
Michelle Bowman
Renewable Electricity Analysis Team,
Office of Electricity, Coal, Nuclear, and Renewables Analysis
U.S. Energy Information Administration, EI-34
1000 Independence Ave., SW
Washington, DC 20585
Phone: (202) 586-0526
E-mail: michelle.bowman@eia.gov

Documentation:
This chapter constitutes the documentation of the CHS.

Archive media and installation manual(s):

The CHS is archived as part of NEMS production runs.

Energy system described:

Conventional hydroelectric supply potential 1 megawatt or greater for impoundment sites (a) undeveloped, (b) with dams but no hydroelectric, or (c) with potential for additional hydroelectric; the supply does not include pumped storage opportunities, in-stream (non-impoundment) potential, ocean-current potential, or refurbishments of existing capacity or operational changes that increase output.

Coverage:

- Geographic: EMM regions 1 – 22 (Note: Alaska and Hawaii are included in the database and processed in the submodule, but excluded from the EMM)
- Time Unit/Frequency: Annual through 2040
- Products: Electricity
- Economic Sectors: Central Station Electricity Generators

Modeling features:

- Modeling Structure: The model operates at the level of individual conventional hydroelectric sites aggregated to segment-level EMM regional averages.
- Model Technique: Levelized electricity costs of each site in each region are arrayed in increasing cost order, then aggregated into three increasing average-cost segments in each iteration in each year, along with corresponding capacity quantities (megawatts), average heat rates, and capacity factors.
- Incorporates short-term cost elasticities of supply, technological optimism, and learning.

Input sources:

The primary data input for the conventional hydroelectricity supply is a dataset prepared specifically to support the modeling. The dataset is prepared under contract by the Idaho National Engineering and Environmental Laboratory. The INEEL contract work integrated data published by Hall, Douglas G., Hunt, Richard T., Reeves, Kelly S., and Carroll, Greg R., (INEEL) in *Estimation of Economic Parameters of U.S. Hydropower Resources* INEEL/EXT-03-00662 (Idaho Falls, Idaho, June 2003), along with information from other documents cited in Appendix 7-C.

Independent expert reviews conducted:

None. However, the CHS methodology was presented at a May 10, 2005 Renewable Electricity Modeling Forum with the specific purpose of exposing the submodule to independent expert review.

Status of evaluation efforts by sponsor:

None.