Concepts, Data Sources, and Techniques
Handbook of Energy Modeling Methods

Short-Term Energy Outlook Model Documentation: Electricity Supply module

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Table of Contents

Table of Figures

1. Introduction

The Electricity Supply module is a component of the U.S. Short-Term Energy Model (USSTEM) within EIA's Short-Term Integrated Forecasting System (STIFS). It provides forecasts for the *Short-Term Energy Outlook* (STEO) for the following data series that measure the performance of U.S. electricity industry operations and markets:

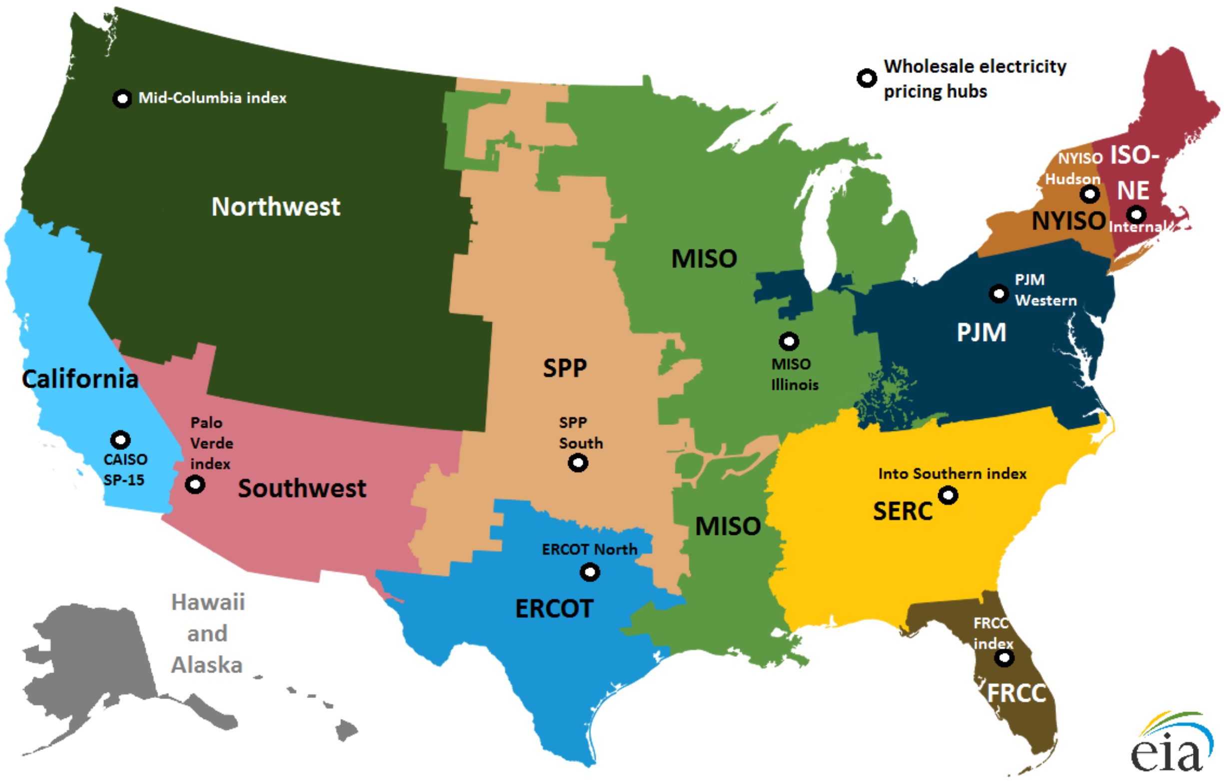
- Electricity generation from the following sources:
  - Natural gas
  - Coal
  - Nuclear
  - Renewable energy
  - Conventional hydropower
  - Wind power
  - Solar power
  - Biomass
  - Geothermal
  - Pumped-storage hydropower
  - Petroleum
  - Other gases
  - Other nonrenewable fuels
- Consumption of the following fossil fuels for electricity generation and useful thermal output
  - Coal
  - Natural gas
  - Petroleum
- Wholesale electricity market prices
- Transmission and distribution losses of electricity
- Net electricity trade between the United States and Canada and between the United States and Mexico

All data series in the Electricity Supply module represent electricity supply from U.S. power plants that have a capacity of at least 1 megawatt (MW), which is consistent with the data reported in our other publications such as the *Electric Power Monthly*. The module produces forecasts of electricity generation and fuel consumption for three sectors:

- Electric power sector
- Industrial sector
- Commercial sector

For each of the three sectors, the Electricity Supply module produces forecasts for the entire United States. In addition, we produce regional electricity generation and fuel consumption forecasts for the electric power sector. The STEO electricity supply regions represent aggregations of geographic areas known as balancing authorities, which are entities that coordinate the supply and demand of electricity within designated areas of the United States. For the regional definitions in the Electricity Supply module, we group the balancing authorities into 12 regions that share generation and transmission infrastructure. The electricity supply regional definitions within USSTEM are similar to the regional definitions used in our other publications such as the *Hourly Grid Monitor* and the *Electric Monthly Update*.

Figure 1. *Short-Term Energy Outlook* (STEO) electricity supply regions



In addition to forecasts of regional electric power sector generation and fuel consumption, we forecast representative wholesale electricity prices for each of the 11 regions in the continental United States. In areas of the country where an organized wholesale market exists, the regional representative price is the one at the hub most commonly cited in trade publications. In areas without wholesale trading, EIA uses spot power prices developed by S&P Global (SNL) as the regional representative price.

Table 1. Short-Term Energy Outlook (STEO) electricity supply regions and associated wholesale electricity prices

STEO Electricity Supply Region	Wholesale Electricity Price Location
New England	ISO-New England Internal hub
New York	New York ISO Hudson Valley zone
Mid-Atlantic	PJM Western hub
Southeast	SERC spot price, Into Southern hub
Florida	Florida Reliability spot price
Midwest	MISO Illinois hub
Central	SPP South hub
Texas	ERCOT North hub
Northwest	Mid-Columbia spot price

Southwest	Palo Verde spot price
California	CAISO SP-15 hub
Hawaii and Alaska	no regional price

2. Electricity Supply Model Structure

We create STEO electricity supply forecasts using two broad inter-related models, which each consist of various component modules: USSTEM and the UPLAN Network Power Model. USSTEM is the primary tool that we use to produce our STEO forecasts across all types of energy sources and market activities. The modules in USSTEM operate as a large system of econometric regression models and identity equations that are solved using the Eviews statistical software. The Electricity Supply module consists of components within USSTEM to estimate the following items:

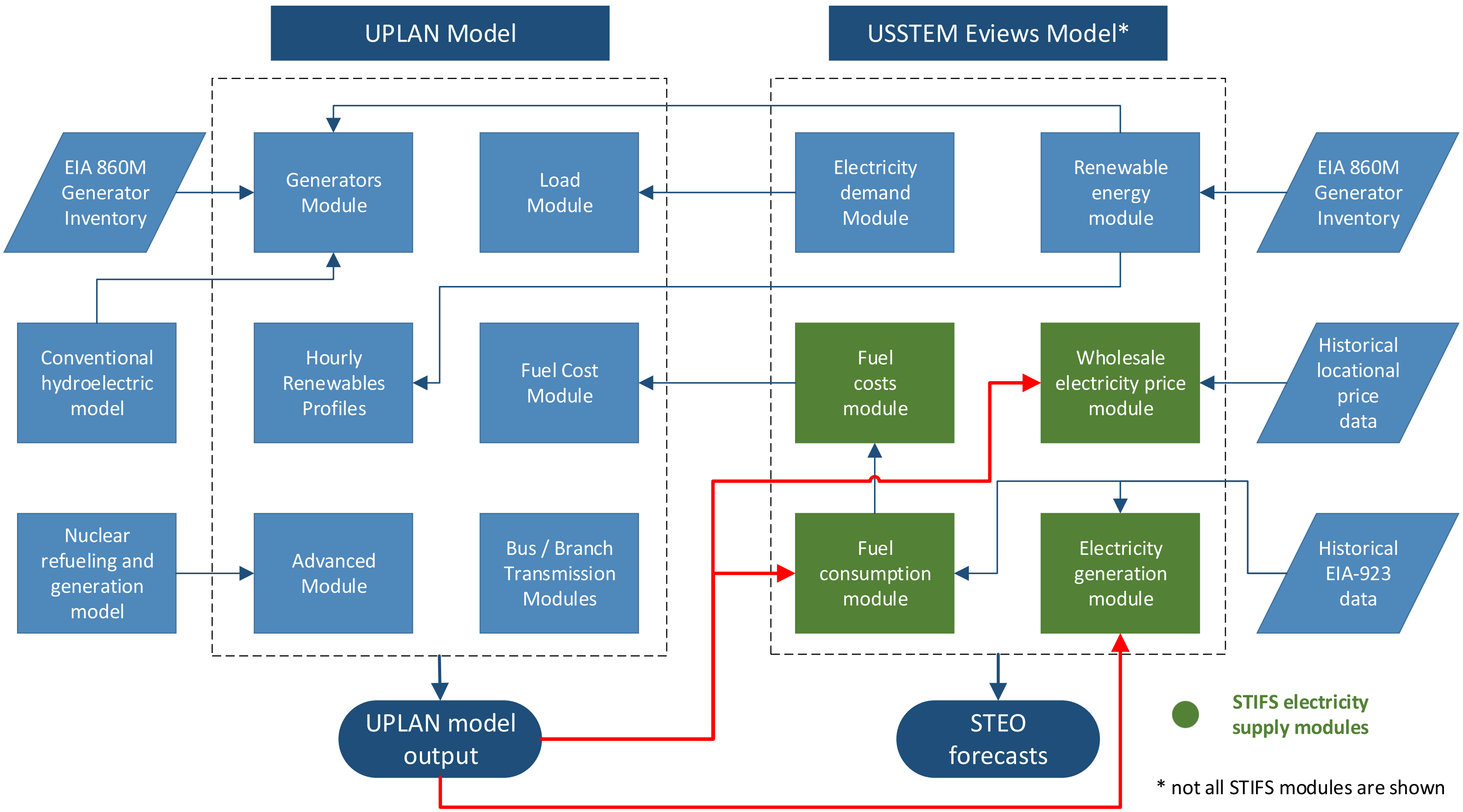
- Electricity generation
- Wholesale electricity prices
- Fuel consumption by power generators
- Cost of fuel delivered to power generators

The module forecasts electricity supply for the commercial, industrial, and electric power sectors. Most of the modeling for the commercial and industrial sectors is done in USSTEM with linear regression models.

To develop the forecasts for electricity supply by the electric power sector, we use a propriety production cost model called UPLAN that was developed by LCG Consulting based in Los Altos, California. UPLAN operates using a more granular time period and geographical representation than USSTEM. The components of the Electricity Supply module in USSTEM use the results from the UPLAN model runs to calculate the STEO electric power sector supply forecasts. Each year, LCG Consulting provides us with a baseline of input information to run UPLAN that they derive from LCG's PLATO database of the electric power industry. We supplement LCG's data with information obtained from our surveys and from third-party sources.

In addition to the data inputs that go into the USSTEM and UPLAN models, data flow between the two models, as shown in Figure 2. Generally, the UPLAN model is solved first, and the solution output is then fed into the USSTEM model in Eviews to produce the published STEO electricity supply forecasts.

Figure 2. Short-Term Energy Outlook (STEO) U.S. electricity supply model components



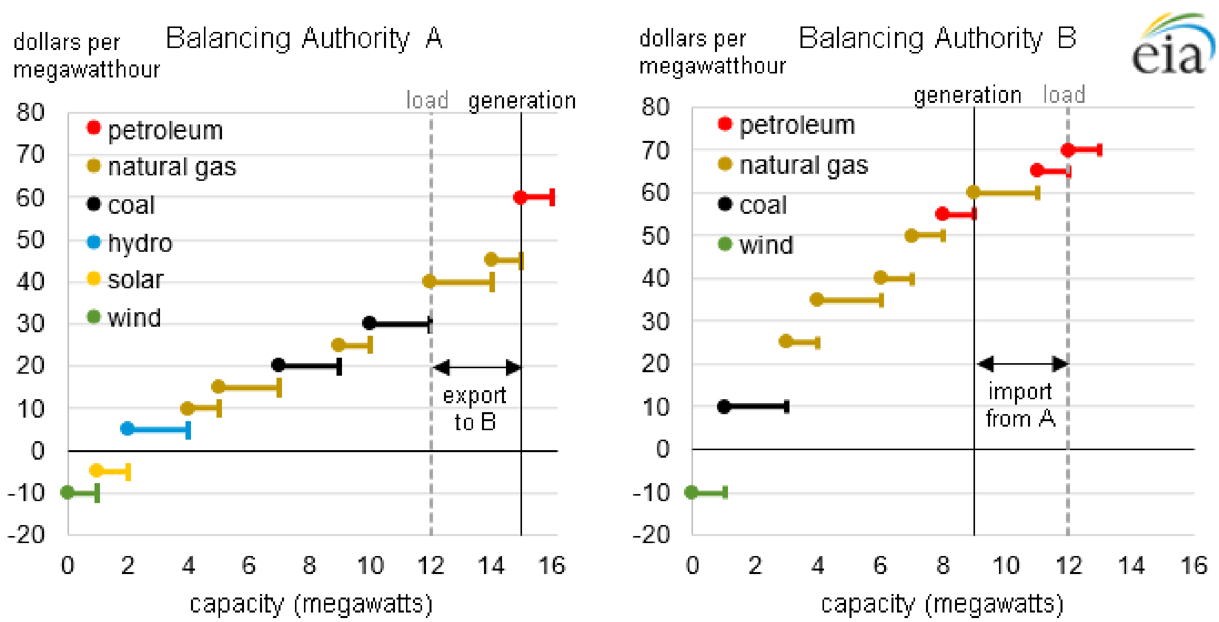
3. UPLAN Network Power Model

We use the Network Power Model (NPM) version of UPLAN to do most of the modeling for the STEO electric power sector supply forecasts. UPLAN NPM is a proprietary software package that functions as a production cost model to simulate electric system operation.

3.1. Production cost model

A production cost model optimizes the dispatch of electricity generation by minimizing total system costs for meeting a specific level of electricity load (demand), subject to various constraints. The optimization can be illustrated with generating capacity dispatch stack charts as shown in Figure 3, which shows the characteristics of a hypothetical electricity system consisting of two balancing authorities, each with similar loads of 12 MW over one hour.

Figure 3. Simple model of electricity dispatch based on production costs



In each chart, the capacities of the generating units in each balancing authority are sorted, or *stacked*, by each generator's offer price, which generally reflects its operating costs. Fossil-fuel power plants have to account for the costs of the fuel used for electricity generation. Renewable energy resources don't incur fuel costs, but they do need to account for other operating and maintenance costs. Some renewables, such as solar and wind, can earn tax credits that more than offset their costs, resulting in negative offers. Although both areas in this example have similar loads, the mix of generating facilities is different. Balancing Authority A has more renewable energy resources and more efficient fossil fuel generators than Balancing Authority B.

In this simplified example, each balancing authority could act independently and use its resources to generate exactly 12 MW of electricity to fulfill the load in each area. In that case, the total costs for Balancing Authority A would be relatively low ($160) while Balancing Authority B would have to spend much more to meet its load ($435). However, if the two balancing authorities dispatch their resources together to meet their combined load of 24 MW, they could lower the total system cost to $535 (compared with $595 in the isolated case above) by having area A generate 15 MW and area B generate 9 MW. In that case, the lower cost Balancing Authority A would generate 3 MW more than its load, and this excess electricity would flow to Balancing Authority B to meet its load.

In reality, electricity supply systems are much more complex than this simple representation, with hundreds (or even thousands) of generating resources and connections between numerous balancing authorities. Furthermore, balancing authorities must meet various system constraints in addition to matching total system generation to total load at each point in time. Some important limitations we must account for are the various physical constraints on electricity flows, such as transmission connections between regions. Production cost models are designed as mathematical formulations that optimize the dispatch of generation resources in a complex electricity supply system while reliably meeting all necessary constraints.

UPLAN NPM is an expanded version of a simple production cost model that works as a two-stage process to simulate generation and power flows between predefined locations. The first stage of the simulation optimizes unit commitment of generation resources for meeting customer load during a given period. The second stage uses a network optimization method to find the lowest cost generation units for each hour in the simulation period that will fulfill each location’s hourly load, subject to the constraints on power flows between points within the system. The model can incorporate various other constraints as well, including generator ramp rate limits, unit availability, renewable resource patterns, fuel supply constraints, etc.

UPLAN optimizes the hourly dispatch of electricity across 125 zones of the continental United States. Some of these zones correspond to balancing authorities, but some zones represent more detailed areas within balancing authorities. The UPLAN model can be run separately for the zones located in the Eastern, Western, and ERCOT (Texas) interconnections. We do not use UPLAN to model electricity operations in Mexico or Canada, but we instead use USSTEM to model electricity imports and exports between those countries and the United States.

3.2. UPLAN data sources

We use forecasts from the Electricity Supply module components of USSTEM and data provided by LCG Consulting for solving the UPLAN model to produce the STEO forecasts. The data are entered into six primary component modules in UPLAN:

- Generator module
- Load forecast module
- Fuel cost forecast module
- Hourly renewables profiles
- Transmission bus / branch module
- Maintenance / outage module

3.2.1. Electricity generators

The largest component of UPLAN's databases is its generator table, which is the the model's primary source of information about electricity supply. The generator table contains a variety of operating characteristics and identifying information for each generating unit in the modeled system. The licensed databases that LCG provides to us each year include an inventory of generating units with detailed information about all of the unit characteristics in the generator table. LCG uses data from various sources, including EIA, to compile this inventory.

To develop the STEO forecast, we merge the characteristics from LCG's database with information from EIA's Preliminary Monthly Electric Generator Inventory, which is based on data from Form EIA-860, *Annual Electric Generator Report*, and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. Merging these two data sources allows us to incorporate the latest information available about generator characteristics—such as installation and retirement dates, planned capacity uprates, or changes in primary energy source—into the STEO forecast. Only those power plants operated by the electric power sector in the continental United States (in other words, excluding Hawaii and Alaska) are used for STEO forecasting in the UPLAN model.

We identify one representative unit for each combination of type of energy source and technology type from the UPLAN generators table. These representative units have the most typical characteristics of each type of generating technology. As we learn about newly announced capacity additions, analysts add these new generators to the database with known information, such as capacity, online dates, and location. Each newly added generator assumes other characteristics used in UPLAN modeling from the representative unit that corresponds to the new generators's energy source and technology.

The database that LCG provides to EIA includes profiles of hourly capacity factors for wind and solar energy generators throughout the United States. These hourly profiles reflect the diverse output performance of renewable energy resources, which can vary substantially based on the geographic location. Some profiles are unique to individual wind or solar projects, while others represent average hourly capacity factors over a broader area.

Power industry investors have installed a large number of relatively small utility-scale solar photovoltaic generating units in recent years. To reduce the model run time without substantially changing the results, we consolidate existing utility-scale solar photovoltaic generators in the Eastern Interconnection that are in the same state and with the same hourly generating profile into a single block of capacity for each state/profile combination. Planned installations of solar generating units are not consolidated. Each planned installation is modeled as available separately after it comes online.

3.2.2. Electricity demand

Electricity demand information for the UPLAN model is contained in the load forecast module. The database provided by LCG includes estimates of monthly net energy for load for each zone for the current year. The database also includes hourly load shapes for each zone during a typical year. The model forecasts hourly load values by applying these hourly load shape factors to estimates of monthly net energy for load for each of the future years.

We develops our forecasts of net energy for load for the STEO electricity supply regions in the Electricity Demand module of USSTEM. Section 4 explains how these forecasts are created. The monthly load forecasts for the 11 continental U.S. STEO regions are converted to monthly load forecasts for the 165 UPLAN modeling zones by applying the relative load shares from a zonal load database supplied by LCG. Forecasts of hourly load within each zone are calculated by applying the hourly load shape factors from LCG's licensed database.

3.2.3. Fuel costs

Fuel cost inputs are one of the primary determinants of the simulated mix of generation fuels in UPLAN. The licensed LCG database includes monthly forecast values for the upcoming year for biomass, uranium, coal, natural gas, and petroleum. However, we forecast our own delivered fossil fuel prices for input into UPLAN to develop the STEO electricity supply forecasts. One of the USSTEM Electricity Supply modules forecasts monthly average fuel costs for natural gas, coal, petroleum liquids, and petroleum coke delivered to the electric power sector. Details about the USSTEM fuel cost module are discussed in Section 4.

USSTEM forecasts regional coal and natural gas fuel costs for the nine census divisions, along with U.S. average fuel cost forecasts for petroleum liquids and petroleum coke. Each fossil fuel generator in UPLAN is assigned its relevant monthly fuel cost data, based on its location. Fuel costs for biomass and nuclear generators are also represented in UPLAN. We use the national prices provided by LCG for this data.

3.2.4. Nuclear power generation

Power generation by nuclear reactors is relatively predictable. Units usually operate at capacity factors of 95% or more, except when a unit is brought down for refueling and maintenance. UPLAN inputs for nuclear generators include each reactor's average monthly capacity factor along with the projected refueling schedules. The UPLAN model treats nuclear generators as must-run units, meaning that they will be committed and dispatched at the specified capacity factors, except during days when they are taken offline for refueling and maintenance.

We have developed a schedule of projected refueling outages for each nuclear reactor, based on an analysis of historical refueling episodes as reported in the Nuclear Regulatory Commission's (NRC) daily status reports. We calculate the median number of refueling days per cycle and the median number of months between refueling cycles from historical NRC data going back to 2010. We assume that the number of days for future refueling episodes is the lower of the number of days in the most recent outage or the median number of historical refueling days per cycle. This selection of scheduled refueling days accounts for fleetwide improvements in the refueling process over time. We adjust median refueling cycle times to fit either an 18-month or 24-month interval. Future reactors are assumed to use an 18-month refueling cycle.

We develop capacity factors for nuclear generators for use in UPLAN by analyzing historical capacity factors for each reactor using monthly generation levels from Form EIA-923, *Power Plant Operations Report*, and historical capacity data from Form EIA-860. These capacity factors only reflect the utilization of their reactors during non-refueling days. For each reactor, we use monthly historical data from the past 10 years to develop a linear regression model of capacity factors. The explanatory variables in each model are the number of refueling days during the month and the number of days the reactor was offline during the month because of a forced outage. We obtain the refueling and forced outage data from the NRC daily status reports. The regression modes provide the UPLAN capacity factor inputs using the scheduled refueling periods and assuming the average monthly forced outage rate over the past 10 years.

4. USSTEM Electricity Supply Modules

We use modules in the USSTEM to create the published STEO electricity supply forecasts for the electric power sector. These modules incorporate information from the UPLAN model solution output. In some cases, such as for nuclear generation, we calculate the STEO monthly forecasts directly from the UPLAN output by summing the simulated hourly generation for a specific energy source and region. In most cases, however, we integrate the UPLAN output into the USSTEM in Eviews, which develops the STEO forecasts for electricity supply by calculating the year-over-year changes in the simulated UPLAN output and applying these changes to historical data.

To create the STEO forecasts for electricity supply with UPLAN output, we first develop a base case scenario in UPLAN that represents a simulation of the previous historical year. In some cases, we may calibrate this baseline scenario by adjusting the generator dispatch offers so that the simulated patterns of generation in each interconnection match the historical data from the Form EIA-923 survey as closely as possible. Simulated forecast-year scenarios include the same generator inventory as the base year historical scenario (including information on scheduled capacity additions/retirements), but they also reflect the input data for load, fuel costs, hydroelectric output, and nuclear outages for each forecast year.

The USSTEM Electricity Supply modules compares year-over-year changes in the UPLAN results for the forecast scenarios with the historical base case and then applies these changes to actual historical data to produce a STEO forecast that is consistent with recent trends. We use variations on this methodology to create the forecasts for electricity generation, fuel consumption, and wholesale power prices.

4.1. Data Sources

The USSTEM modules use monthly data, and the STEO tables report monthly values. Our primary source for historical data in the electricity generation and fuel consumption modules is Form EIA-923. In this survey, we collect information on the operation of electric power plants and combined heat and power (CHP) plants in the United States that each have a total generating capacity of at least 1 MW. The information includes data on electric power generation, fuel consumption, fossil fuel stocks, and delivered fossil fuel cost.

For most EIA publications, we aggregate power plant data from the Form EIA-923 to the state or census division level. To produce the STEO forecasts, however, the USSTEM Electricity Supply modules create historical Form EIA-923 estimates by aggregating across balancing authorities to the regions shown in Figure 1. The national-level historical electricity data published in the STEO should match U.S. data from other EIA publications such as the *Electric Power Monthly* and *Monthly Energy Review*.

To calculate historical electricity generation and fuel consumption estimates, we group balancing authorities into regions as they are grouped for our Electric System Operating Data system. Information about the balancing authority associated with individual generating plants comes from the Form EIA-860 survey. This set of regional definitions is based on the *current* geographic footprint of electricity market regions. We use this approach to make the historical estimates more consistent with the way the industry would have operated in the past given the current structure of electricity markets. The resulting data may not accurately represent historical generation in the previous structure of these markets.

USSTEM also uses monthly wholesale electricity prices. For the STEO regions that match a regional transmission organization (RTO) or independent system operator (ISO) area, USSTEM calculates a historical monthly price as the simple average of the locational marginal prices (LMPs) at the region's hub during on-peak hours (7:00 a.m.–10:00 p.m., Monday–Friday, excluding holidays). For the STEO regions in areas without an ISO or RTO (Northwest, Southwest, SERC, and FRCC), the historical wholesale price is the average of the daily on-peak spot power price values for the regional hub as reported by S&P Global Market Intelligence.

4.2. Electric Power Sector Generation Forecasts

USSTEM models electricity generation by energy source in the electric power sector using shares of total generation to ensure that estimates of component values by source sum to the estimated total. The use of generation shares also tends to reduce volatility in forecast year-to-year changes, compared with using absolute changes or percentage growth. USSTEM calculates the STEO electricity generation forecasts by applying year-over-year changes in generation shares from the UPLAN simulations to the historical generation share for the base case year.

For the continental United States as a whole, electricity supply must balance electricity demand. Total continental U.S. electric power sector generation is defined in USSTEM to be equal to the total continental U.S. load (electricity demand delivered over the power grid), and we assume no unserved load exists. So, total continental U.S. electric power sector generation (and total U.S. electricity load) is a combination of the following variables:

- U.S. retail sales of electricity across all sectors
- U.S. electricity transmission and distribution losses
- U.S. direct use of electricity by combined heat and power generators
- U.S. generation of electricity by combined heat and power generators
- U.S. net imports of electricity from Canada and Mexico
- Total generation of electricity in Hawaii and Alaska

Total supply of electricity is equal to total demand, adjusted for any net imports of electricity from outside the United States, and also includes transmission and distribution losses. USSTEM estimates total U.S. electricity imports and exports using a linear regression equation. The explanatory variables in these equations are as follows:

- Monthly dummy variables to reflect seasonality
- Total U.S. hydroelectric generation

- Relative prices of U.S. natural gas and coal fuel costs

Transmission and distribution losses are also modeled with a linear regression equation using the ratio of losses to total U.S. retail sales of electricity as the dependent variable. The independent variables include monthly dummies and the number of cooling and heating degree days to account for extreme temperatures.

Although a few direct current (DC) transmission links exist between the three North American interconnections, allowing small amounts of electricity to flow between them, we assume for modeling purposes that the total generation in each interconnection is equal to its load and that no power flows outside of the interconnection. Econometric equations in USSTEM estimate the total load/generation for the Western and Texas interconnections. The model calculates total load/generation for the Eastern Interconnection as the difference between continental U.S. load/generation and the sum of the Texas and Western values.

Electricity generated in one region is made available to meet the load in that region or any other region within the interconnection. Therefore, the load values for each STEO region may not necessarily equal the forecast level of generation for that region because electricity may flow between areas within an interconnection. Forecasts of total electricity generated in each region are calculated within the USSTEM by applying the year-over-year change in the region-to-interconnection generation. It is not necessary to estimate generation shares for the ERCOT market because it is the only STEO modeling region in the Texas Interconnection.

The forecast generation for each energy source within the STEO electricity supply regions are determined in a similar way—by applying year-over-year changes in the fuel's share of total regional generation from the UPLAN simulation. Because we estimate generation for each type of fuel using generation shares in USSTEM, the sums of the fuel-specific generation values are equal to the total regional generation forecasts.

4.3. Electric Power Sector Fuel Consumption Forecasts

The consumption of fossil fuels for electricity generation depends on both the amount of electricity generated and the heat rate of the generating units that are dispatched. Each generator in the UPLAN model simulation is assumed to have heat rates that vary depending on the amount of the generator's capacity that is dispatched. For natural gas and coal, USSTEM forecasts monthly fuel consumption for each region by multiplying the forecast electricity generation by the average regional heat rate from the same month in the previous year, adjusted by a factor that accounts for change from the previous year, in the UPLAN simulated aggregate heat rate.

The amount of petroleum liquids consumed for electric generation is relatively small compared with that of coal or natural gas. USSTEM calculates the consumption of petroleum fuels using a simple identity that relates modeled fuel consumption to modeled electricity generation and the average heat rate over the previous 12 months. Using an average heat rate for each fuel over a longer period avoids the possibility of model errors if generation from that fuel in any given month is zero. For regions that have not historically used any petroleum liquids for generation, we assume that the forecast level of consumption is zero.

4.4. Commercial and Industrial Sector Electricity Supply Forecasts

In addition to the electric power sector, we publish electricity generation and fuel consumption by the commercial and industrial sectors. Power plants operated within these two sectors are generally combined heat and power (CHP) units that provide power to commercial or industrial establishments for use onsite and may supply excess generation to the transmission grid. We only forecast national (not regional) generation and fuel consumption for the commercial and industrial sectors in the STEO.

USSTEM first forecasts the amount of each fossil fuel consumed for electricity generation by U.S. CHP generators in the commercial and industrial sectors, and then the module develops forecasts of generation levels from these fuel consumption forecasts. The fuel consumption forecasts are generally estimated using regression models where the independent variables are:

- U.S. electricity-weighted industrial production index (industrial sector equations)
- U.S. level of private-sector employment (commercial sector equations)
- U.S. average cost of associated fossil fuel

These fuel consumption forecasts are then used by other modules within USSTEM. Forecasts of electricity generation by CHP generators for each fossil fuel type are developed using regression equations where the primary independent variable is the level of fuel consumption.

For most non-fossil sources of power generation in the commercial and industrial sector, USSTEM sets the forecast equal to the level of generation in the same month from the previous historical year. However, U.S. industrial and commercial forecasts for wind and solar generation are developed from regression models using the total amount of generating capacity as the main explanatory variable.

4.5. Delivered Fuel Cost Forecasts

The relative cost of fossil fuels is one of the primary determinants of the mix of energy sources used for electricity generation. Forecasts for the costs of fuel delivered to power generators are developed in USSTEM using regression models, and these monthly forecast values are passed through as inputs into the UPLAN model as discussed in Section 3. Fuel costs for petroleum liquids and petroleum coke are modeled at the national level. For the average U.S. delivered cost of petroleum liquids, the explanatory variables in the model equation include the following:

- WTI crude oil price (current month and lagged month values)
- Monthly change in U.S. electric power sector distillate fuel oil stocks

The explanatory variables for U.S. petroleum coke fuel cost are

- West Texas Intermediate (WTI) crude oil price (current month and lagged month values)
- U.S. cost of coal for power generation (current month and lagged month values
- Monthly change in U.S. electric power sector petroleum coke stocks

Forecasts of delivered fuel costs for natural gas and coal are developed from regression models for each census division. The dependent variable in the regional natural gas fuel cost equations is the difference between the regional cost and the Henry Hub natural gas spot price. The independent variables in the regional natural gas cost equations include

- Difference between census division cooling degree days and the previous 10-year average
- Difference between census division heating degree days and the previous 10-year average
- Monthly dummy variables
- Dummy variable for months in which the Henry Hub spot price exceeds $3.50 per million Btu

The regression model equations for regional costs of coal delivered to power generators include the following explanatory variables:

- U.S. weighted average spot price of coal
- U.S. diesel fuel price
- U.S. electric power sector coal stocks
- Monthly dummy variables
- Dummy variable for months in which the Henry Hub spot price exceeds $3.50 per million Btu

The regression model equations for delivered costs of both regional natural gas and coal include a dummy variable for Henry Hub natural gas prices above $3.50 per million Btu, because, at this price level, the relative amount of generation between coal and natural gas becomes more volatile.

4.6. Wholesale Electricity Price Forecasts

LMP forecasts are among the primary outputs of the UPLAN electricity model, and they provide the value of electricity at certain locations and reflect electricity generation and load patterns as well as transmission system limits. The zonal version of UPLAN produces LMPs for each of the 125 zones represented in the zonal model. Instead of reporting all of these zonal results in the regular STEO publication, we report a representative wholesale price for each STEO supply region. USSTEM bases the forecast values for these wholesale prices on one or more of the zonal LMPs within the STEO supply region, as shown in Table 1. Some STEO supply regions use the LMP from a single UPLAN zone as the representative wholesale price. In other STEO regions, the wholesale price is calculated as the load-weighted average of the prices from multiple zones.

UPLAN also breaks out the LMP into energy, congestion, and loss components. The forecast wholesale price we publish in the STEO represents the full LMP, including all these elements. To produce wholesale price forecasts for the STEO that are consistent with recent historical trends, the STEO model bases its projections on the year-over-year growth rates in the simulated UPLAN LMPs.