Independent Statistics & Analysis
U.S. Energy Information Administration

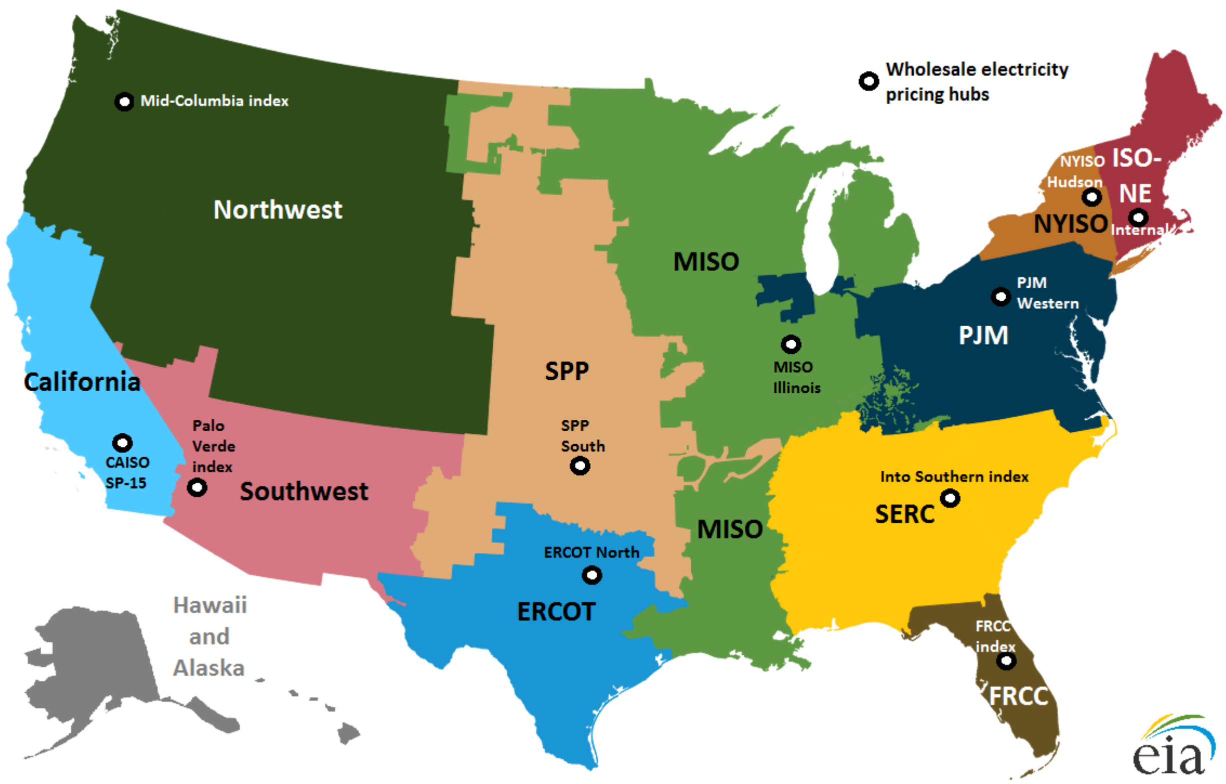
Short-Term Energy Outlook Supplement: Expanded Forecasts for Wholesale Electricity Prices and Electricity Generation & Fuel Consumption

August 2019

1. Overview

Beginning with the August 2019 *Short-Term Energy Outlook* (STEO), the U.S. Energy Information Administration (EIA) is revising the presentation and modeling of its forecasts for electricity supply and pricing in the United States to better reflect U.S. electricity markets and operations. EIA is introducing forecasts of electric power sector generation and fuel consumption for 12 electricity supply regions, as shown in Figure 1. These revised STEO forecast regions generally correspond to the current structure of electricity market and system operations areas in the United States. In addition, EIA is beginning to forecast average peak-period wholesale electricity prices for each STEO electricity supply region, with the exception of Hawaii and Alaska.

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



Source: U.S. Energy Information Administration

EIA has traditionally presented electricity data in its publications for geographical areas using state boundaries and groups of states such as census divisions or regions. The STEO had produced forecasts of electricity generation and fuel consumption for the four broad census regions (Northeast, Southeast, Midwest, and West). However, a state-based geographic representation of the data does not adequately reflect how the industry produces and supplies electricity in the United States.

The structure of the electricity industry and the behavior of power generators vary among different areas of the country. U.S. electricity supply and demand is coordinated by power operators working within various geographic areas known as balancing authorities that are distributed throughout the three main U.S. interconnections (East, West, and Texas). Some balancing authorities operate centralized wholesale electricity markets that match electricity generation with electricity demand.

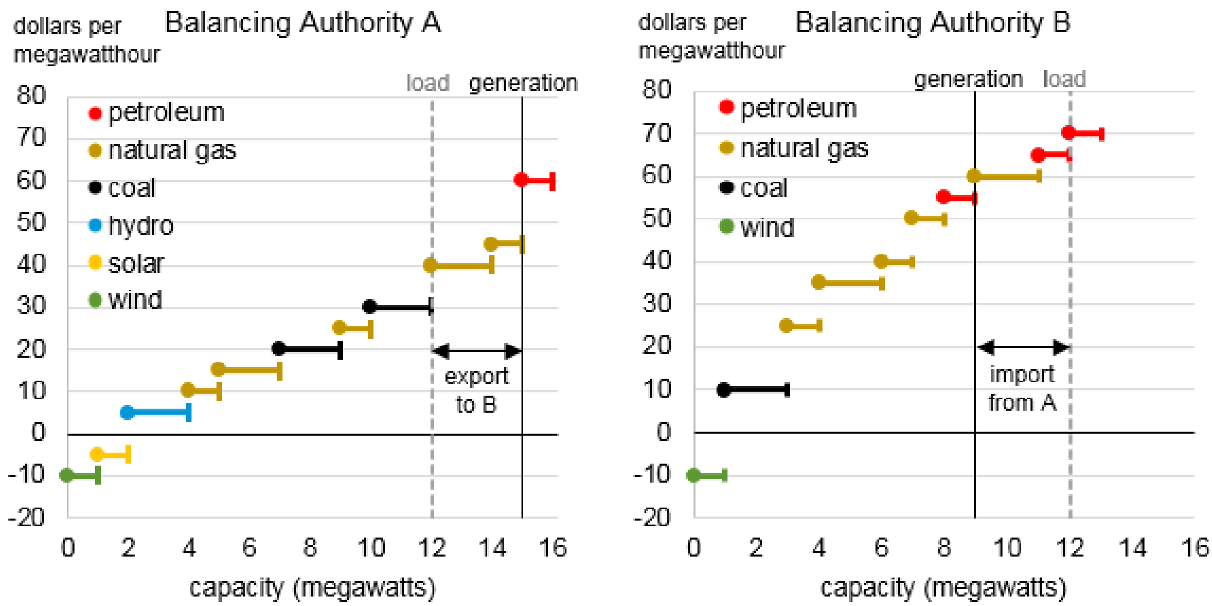
Balancing authorities with wholesale electricity markets are usually associated with an electric grid operated by a regional transmission organization (RTO) or independent system operator (ISO). In other parts of the country, power generators and electric distribution companies allocate electricity through bilateral transactions and other agreements. In either case, the lowest cost electricity generators are generally selected (dispatched) to fulfill area electricity demand at any point in time, all while accounting for various constraints that reflect the limitation of the electricity system. The new electricity supply regions in the STEO better reflect how electricity is produced in balancing authority dispatch areas and wholesale markets.

Redefining the electricity supply regions in the STEO also provides EIA the opportunity to present new forecasts of wholesale electricity prices that can measure the value of electricity supplied in different areas of the United States. Wholesale electricity prices are often measured using the concept of a locational marginal price (LMP), which represents the value of electricity at a certain location within an ISO or RTO. LMPs reflect the region's generation and load patterns along with transmission system limits. The regional STEO wholesale hub price forecasts act as summary measures of LMPs in areas managed by ISOs and RTOs, and they represent the value of bilateral transactions in other dispatch areas of the country.

In addition to expanding the available STEO electricity supply and pricing forecasts, EIA has also redesigned its short-term model to produce these forecasts. The forecasts published in the STEO are developed in EIA’s Regional Short-Term Energy Model (RSTEM), which consists of an integrated system of equations and identities that link the various components of the U.S. energy industry together. RSTEM consists of submodules for each energy source (crude oil, electricity, coal, etc.) and industry function (production, demand, prices, etc.).

The new structure of the electricity supply module in RSTEM is based on a production cost modeling framework. A production cost model optimizes the dispatch of electricity generation by minimizing total system cost for meeting a specific level of electricity load (demand) subject to the limitations of various constraints. The optimization can be illustrated with generating capacity dispatch stack charts as shown in Figure 2, which shows the characteristics of a hypothetical electricity system consisting of two balancing authorities, each with similar load of 12 megawatts (MW) over one hour.

Figure 2. Hypothetical electricity generation capacity dispatch stack for two balancing authorities



Source: U.S. Energy Information Administration

In each chart, the capacity of the generating units in each balancing authority are sorted, or *stacked*, by each generator's offer price, which generally reflects their 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 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) whereas 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 so that it can 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. 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.

EIA's revised forecasting approach models electricity supply for the STEO forecasts using the UPLAN production cost optimization model package that was developed by LCG Consulting based in Los Altos, California. EIA uses the solution results provided by this proprietary software package to develop the STEO forecasts of monthly electricity generation, fuel consumption, and wholesale prices. The UPLAN model uses input data assumptions that are derived from EIA historical data sources and from other modules with RSTEM, along with data provided by LCG. The electricity supply modules within RSTEM use information from the UPLAN model solution output to create the published STEO electricity forecasts.

The next section of this STEO supplement provides a general overview of the UPLAN Network Power Model and how EIA links it with RSTEM. Section 3 describes the data that are used by the RSTEM electricity model, including the sources for this information. Section 4 shows the general convention for naming model variables in RSTEM. Section 5 discusses the development of the input assumptions for the UPLAN model. Section 6 describes how the UPLAN solution output is incorporated into the RSTEM model to produce the STEO forecasts for electricity generation, fuel consumption, and wholesale price forecasts. The final section of this supplement discusses how the forecast data are published in the standard STEO tables.

2. UPLAN Network Power Model

LCG Consulting's UPLAN software package is an integrated modeling tool for simulating electricity industry operations and power markets on an hourly basis. The foundation of UPLAN is a production cost (or economic dispatch) model, designed to simulate the way a bulk power system operates. A production cost model determines the lowest cost way to dispatch a system of interconnected generators to meet the system's electricity load (demand) at every location at every hour during the simulation period.

The UPLAN Network Power Model (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 dispatches the lowest cost generation units for each hour in the simulation period so that each location's hourly load is fulfilled, while meeting the constraints on power flows between points within the system using a network optimization methodology. The model can incorporate various other constraints as well, including generator ramp rate limits, unit availability, renewable resource patterns, fuel supply constraints, etc.

The complexity and realism of model simulations with UPLAN-NPM depend on the locational representation with the modeled power system. The most accurate representations involve modeling individual electrical nodes within the power system. Each generating unit and load point is assigned to a node within the network database. Interconnecting branches are established between the individual nodes to attempt to realistically mimic the flow of power on the U.S. transmission network.

When UPLAN-NPM is configured with this nodal locational structure, it can be run as a full-featured optimal power flow (OPF) model that represents security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) at the most granular geographic level possible. UPLAN-NPM's network optimization algorithm can solve with a full alternating current (AC) or direct current (DC) transmission network model that incorporates detailed branch characteristics such as voltage, reactance, and resistance properties. A full AC/DC OPF simulation of UPLAN-NPM typically optimizes across hundreds or thousands of nodes and can involve considerably long run times.

Such nodal modeling is very resource-intensive and is most appropriate for analyzing scenarios in localized geographical areas for a short simulation period. A more manageable approach for modeling the electricity system of the entire United States is to structure locations in UPLAN-NPM into zones that represent a large number of nodes within a geographical area. These zones are typically defined to represent balancing authorities or groups of balancing authorities. These zone definitions include all the generators supplying power to the balancing authorities, and each zone has total hourly load the model must fulfill. Branches are defined in UPLAN-NPM to connect the zones and to model power flows. Zonal model branch constraints generally do not reflect all the electrical characteristics as branch constraints in a nodal OPF model. Branches in a zonal model are typically constrained only by the line rating (i.e., the maximum power that can flow on each branch).

Structuring UPLAN-NPM as a more manageable zonal model for use in RSTEM is appropriate because the STEO produces forecasts that cover the entire United States for as long as a two-year period. However, UPLAN-NPM provides EIA the flexibility to augment the STEO forecast by running the model in nodal/OPF mode for scenarios with a more limited scope.

Figure 3 provides an overview of the relevant modules of the UPLAN model and the RSTEM model, and it illustrates how data flow between the components of the two models. The six primary components of the UPLAN model are the

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

These components of UPLAN-NPM incorporate various sets of input data and assumptions for solving the model. Each year, LCG Consulting provides EIA with a baseline set of input information for these modules that it derives from LCG’s PLATO database. EIA supplements LCG’s data with information obtained from EIA’s surveys and other third-party sources. Section 4 describes the input data in more detail.

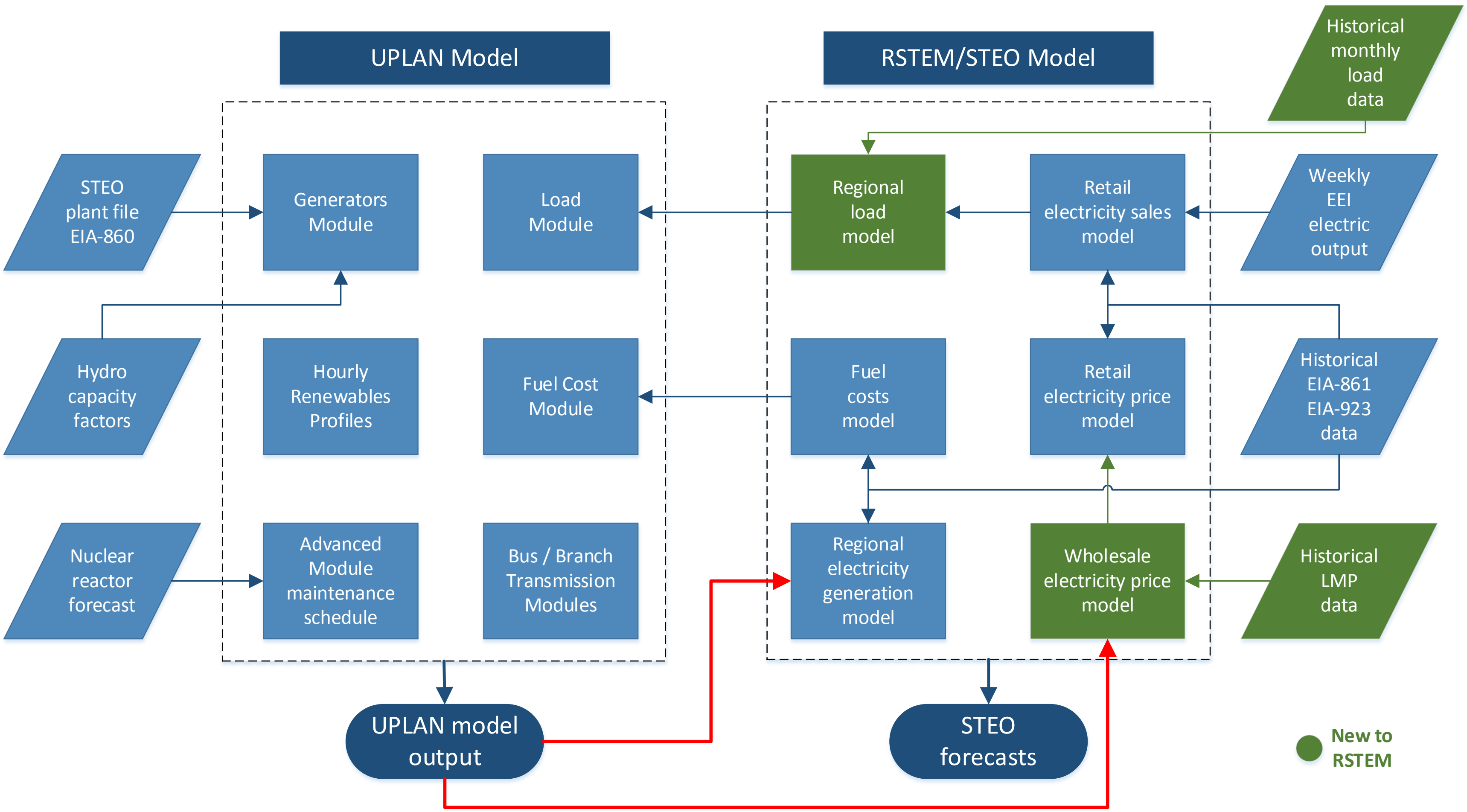
UPLAN-NPM produces a large amount of detailed output that summarizes model solutions. Output reports describe results such as

- Generation and fuel consumption
- Operating costs for individual units
- Energy flows between zones or nodes
- Locational marginal price information

UPLAN produces reports that show hourly results or can be aggregated to other periods, and they can summarize output for different geographical areas. Section 5 describes how EIA incorporates the report output from UPLAN-NPM solutions into RSTEM for creating the STEO electricity supply forecasts.

RSTEM contains six electricity-related modules. The electricity generator fuel cost model and the electricity demand (load) model provide input data for running the UPLAN model. Output report data from the UPLAN model solution provide input back into the RSTEM electricity supply (generation and fuel consumption) and wholesale price models to produce the STEO forecasts. The next section discusses the structure and source of data for the electricity supply variables in RSTEM.

Figure 3. Data flow between UPLAN model and RSTEM model



Source: U.S. Energy Information Administration
Notes: RSTEM = Regional Short-Term Energy Model, EEI = Edison Electric Institute, LMP = locational marginal price

3. RSTEM electricity supply variables and data

The variables EIA uses in the RSTEM model generally follow a similar naming convention that identifies the energy source, the type of product/activity, and the location. Table 1 provides an illustration for one of the STEO electricity generation variables.

Table 1. RSTEM variable naming convention, example for PJM region coal generation

Variable name: CLEPGEN_PJ

Characters	CL	EP	GEN	PJ
Position	1 and 2	3 and 4	5	7 and 8
Identity	Energy source	Industry sector	Type of variable	Location

In this example, CLEPGEN_PJ is the variable name for electric power sector (EP) coal (CL) generation (GEN) in the PJM (PJ) region. The electricity supply model in RSTEM provides forecasts for three types of variables:

- GEN – Net generation
- CNS – Fuel consumption
- LOAD – Net energy for load

Electricity supply in the electric power sector is modeled on a regional basis using the UPLAN model. The modeling of electricity supply in the commercial and industrial sectors is discussed later in the documentation. The variable coding for the two sectors is

- EP – Electric power sector
- IN – Industrial sector
- CM – Commercial sector

The variable codes for the energy sources used to produce electricity are listed in Table 2.

Table 2. Fuel codes used by RSTEM model

CL – Coal	NU – Nuclear
NG – Natural gas	HP – Pumped storage hydropower
PA – Petroleum	RT – Renewable energy sources
RF – Residual fuel oil	HV – Conventional hydropower
DK – Distillate fuel oil	WN – Wind power
OP – Other petroleum liquids	SO – Solar
PC – Petroleum coke	BM – Biomass
OG – Other gases	GE – Geothermal

As discussed above, the RSTEM electricity supply model works with data for 12 regions, as shown in Figure 1. The location identifiers in the model variable names are

- NE –New England (ISO-NE)
- NY – New York (NYISO)
- PJ – Mid-Atlantic (PJM RTO)
- SE – Southeast Reliability Council (SERC)
- FL – Florida Reliability Council (FRCC)
- MW – Midwest (Midcontinent ISO)
- TX – Electric Reliability of Texas (ERCOT)
- SP – Central (Southwest Power Pool)
- CA – California
- SW – Southwest
- NW – Northwest
- HA - Hawaii and Alaska

The wholesale electricity hub price variables in RSTEM are named in a similar way. These variable names use the standard STEO code for price (U) to indicate the variable type. For example, ELWHU_CA is the variable name for the electricity (EL) wholesale (WH) price (U) in California's (CA) hub.

Table 3. RSTEM wholesale price variable naming convention, example for California region

Variable name: ELWHU_CA

Characters	EL	WH	U	CA
Position	1 and 2	3 and 4	5	7 and 8
Identity	Energy source	Industry sector	Type of variable	Location

The RSTEM modules solve with a monthly frequency. Consequently, EIA must structure its data inputs into RSTEM with a monthly format, and the STEO tables report monthly values. EIA's primary source for historical data in the electricity generation and fuel consumption models is Form EIA-923, *Power Plant Operations Report*. EIA uses this survey to collect information on the operation of electric power plants and combined heat and power (CHP) plants in the United States that have total capacity of at least 1 MW. The information includes data on electric power generation, fuel consumption, fossil fuel stocks, and delivered fossil fuel cost.

Most EIA publications present data from Form EIA-923 by aggregating the power plant information to the state level or census division level. To produce the STEO forecasts, the RSTEM electricity model creates historical data from Form EIA-923 by aggregating across balancing authorities to the regions shown in Figure 1.

Information about the balancing authority associated with individual generating plants comes from the Form EIA-860 survey, *Annual Electric Generator Report*. EIA groups balancing authorities into zones for the STEO electricity supply data like they are for EIA's Electric System Operating Data system. This method of mapping balancing authorities into modeling zones for calculating historical data is based on the *current* geographic footprint of electricity market regions. EIA uses this approach to make the STEO forecasts 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.

EIA obtains data for historical monthly net energy for load from the North American Electric Reliability Corporation's (NERC) Energy and Supply (ES&D) database, which is based on information collected through the Form EIA-411 survey, *Coordinated Bulk Power Supply Program Report*. Recent load data comes directly from the individual ISO and RTO websites, and EIA estimates some load data using the Electric System Operating Data system.

Historical wholesale electricity prices are also structured on a monthly basis in RSTEM. For the STEO regions that match an RTO or ISO area, historical monthly prices are calculated as the simple average of the LMPs at that 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 price index values for the regional hub as reported by S&P Global Market Intelligence.

The representative historical wholesale electricity prices are shown in Table 4. EIA develops a forecast wholesale electricity price from the UPLAN model results for each STEO region. Some of these forecast electricity prices are calculated directly from the modeled LMP for a specific UPLAN zone. In other cases, the forecast price is based on a load-weighted average of a collection of the zonal LMPs in the STEO region. More detail about modeling the STEO wholesale price forecasts is provided in Section 6.

Table 4. STEO region wholesale price locations

STEO region		Representative historical price	Forecast LMP in UPLAN zone(s)
Eastern Interconnection			
NE	New England	ISO-NE Internal hub LMP	NEP_WCMA
NY	New York	NYISO Hudson (zone G) LMP	NY_HUDSON
PJ	Mid-Atlantic	PJM Western hub LMP	PJM_PENELEC, PJM_PEPCO, PJM_BGE, PJM_METED
MW	Midwest	MISO Illinois hub LMP	MISO_AMIL, MISO_CWLP, MISO_SIPC
SP	Central	SPP South hub LMP	SPP_AEPW, SPP_OKGE, SPP_WFEC
SE	Southeast	Southern index	SOCO_SOCO
FL	Florida	FRCC index	FRCC
Western Interconnection			
NW	Northwest	Mid-Columbia index	NORTHWEST
SW	Southwest	Palo Verde index	ARIZONA
CA	California	CAISO SP-15 LMP	SOCAL, SANDIEGO
Texas Interconnection			
TX	Texas	ERCOT North LMP	LZ_NORTH

4. UPLAN model input data

At the beginning of each year, LCG Consulting provides EIA with new datasets from its PLATO database, which covers the Eastern, Western, and Texas Interconnections. These datasets provide information about many of the North American power system's characteristics including operational data for generators, hourly availability profiles for wind and solar generators, hourly load profiles for each model zone, and the line rating characteristics of the connecting branches.

The databases used in UPLAN use zone definitions that generally correspond with the geographic footprints of balancing authorities or areas managed by reliability coordinators. The Eastern Interconnection database has about 125 zones, the database covering the Western Interconnection has 35 zones, and the database for the Texas Interconnection has 4 zones. Ten of the zones in the Eastern and Western databases represent Canadian areas, and one zone represents the Mexico-CFE (Comisión Federal de Electricidad) area within the Western Interconnection. For STEO electricity supply forecasts, only the zones located within the continental United States are modeled in UPLAN.

The databases provided by LCG include a blend of public and proprietary information and are provided annually under EIA's license. EIA updates the STEO forecasts monthly, and therefore must incorporate information that changes on a more frequent basis. To create the STEO forecasts, EIA uses data inputs for the UPLAN model that consist of a blend of information from LCG's annual PLATO database, EIA monthly survey data, input data from other RSTEM modules, and some exogenous forecasts.

LCG's licensed database accounts for a large share of the input information used for solving the UPLAN model to create the STEO forecasts. Each month, EIA compiles information to update five primary categories of data in the database:

- Generator characteristics
- Zonal load forecasts
- Fuel cost forecasts
- Hydro generation forecasts
- Nuclear reactor performance

Generator characteristics

The largest component of UPLAN's databases is its generator table, which is the primary source of information in the model 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 EIA each year include an inventory of generating units with detailed information about all of the unit characteristics in the generators table. LCG develops this inventory from various sources, including EIA.

To develop the STEO forecast, EIA merges the characteristics from LCG's database with information from EIA's *Preliminary Monthly Electric Generator Inventory* (which is based on the Form EIA-860 and Form EIA-860M surveys). Merging these two data sources allows EIA 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. Only those power plants operated by the electric power sector in the continental United States (i.e., excluding Hawaii and Alaska) are used for STEO forecasting in the UPLAN model.

EIA identifies one representative unit for each combination of fuel type and prime mover from the UPLAN generators table because these units have the most typical characteristics of each type of generating technology. As EIA learns about newly announced capacity additions, these new generators are added to the database with known information such as capacity, online dates, and location. The new generators assume other characteristics used in UPLAN modeling from the representative unit corresponding to that generator's fuel source and prime mover.

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, EIA consolidates existing utility-scale solar photovoltaic capacity in the Eastern Interconnection into a single entry for each zone and hourly generating profile. Planned installations of solar generating units are not consolidated so that they will be made available separately in the model after they come online.

Zonal load forecasts

The primary inputs for electricity demand in the UPLAN model are the hourly load forecasts for each zone. To maintain stability in an electrical transmission system, power generators must produce enough electricity at each point in time to meet electricity demand, often referred to as electrical load. Net energy for load is the amount of generation that generators must produce to meet an area's electricity demand, accounting for transmission and distribution losses and for electricity flows into and out of the area.

The UPLAN database provided by LCG includes estimates of monthly zonal net energy for load 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 shapes to estimates of monthly net energy for load.

For the continental United States as a whole, electricity supply must balance electricity demand. The RSTEM model connects these two parts of the industry using the following identity for total electricity load supplied by the electric power sector in the continental United States:

$$\begin{aligned} ELLOAD_{COUS} &= EXRCP_{US} + TDLO_{US} + ELDU_{US} - CHEO_{US} - ELNI_{US} - TOEPGEN_{HAK} \\ &= TOEPGEN_{COUS} \end{aligned} \quad (1)$$

where

$ELLOAD_{COUS}$ = total electricity load, continental United States
$EXRCP_{US}$ = U.S. retail sales of electricity across all sectors
$TDLO_{US}$ = U.S. electricity transmission and distribution losses
$ELDU_{US}$ = U.S. direct use of electricity by combined heat and power generators
$CHEO_{US}$ = U.S. generation of electricity by combined heat and power generators
$ELNI_{US}$ = U.S. net imports of electricity from Canada and Mexico

$TOEPGEN_{HAK}$ = total generation of electricity in Hawaii and Alaska
$TOEPGEN_{COUS}$ = total generation of electricity, continental United States

One of the modules within RSTEM provides initial forecasts of monthly net energy for load for each of the STEO regions. The model creates these regional load forecasts from econometric equations in which the primary explanatory variables are retail sales of electricity. The retail electricity sales module in RSTEM creates forecasts for the 10 census divisions, which do not perfectly align with the new STEO electricity supply regions. The load forecasts for each STEO electricity supply region are a function of retail sales in the census region that is most closely matched with the supply region. EIA also includes cooling and heating degree day forecasts for the component states as explanatory variables.

The following equation shows an example for forecasting an initial estimate of load in the Southwest electricity supply region:

$$\begin{aligned} ELLOAD_t^{*SW} = {} & b_1 EXTCP_t^{MTN} + c_1 ZWCD_t^{AZ} + c_2 ZWCD_t^{NM} + c_3 ZWHD_t^{AZ} + c_4 ZWHD_t^{NM} \\ & + d_1 JAN_t + d_2 FEB_t + d_3 MAR_t \cdots + d_{10} OCT_t + d_{11} NOV_t + d_{12} DEC_t \end{aligned} \quad (2)$$

where

$ELLOAD_t^{*SW}$ = initial estimate of electricity load in Southwest STEO electricity supply region
$EXTCP_t^{MTN}$ = total retail sales of electricity in Mountain Census division
$ZWCD_t^{S}$ = cooling degree days for *S* = Arizona (AZ) and New Mexico (NM)
$ZWHD_t^{S}$ = heating degree days for *S* = Arizona (AZ) and New Mexico (NM)
$JAN_t,\ FEB_t, \ldots NOV_t, DEC_t$ = monthly dummy variables

The Midcontinent ISO (MISO) STEO electricity supply region has two separate load equations to forecast load in the northern and southern areas of the region.

The RSTEM model then scales the initial estimates of monthly net energy for load ($ELLOAD_R^*$) from the regional equations by the ratio of the total load for the continental United States, as calculated in equation (1), and the sum of the initial regional loads estimates:

$$ELLOAD_{SW} = ELLOAD_{SW}^* \times \frac{ELLOAD_{COUS}}{\sum_R ELLOAD_R^*} \quad (3)$$

The model then distributes these adjusted monthly load forecasts for the 11 continental U.S. STEO regions to the 165 UPLAN modeling zones by applying the relative shares from the zonal load database supplied by LCG. Forecasts of hourly load within each zone are calculated by applying the hourly load shapes from LCG's licensed database.

Fuel costs forecasts

EIA's forecast fuel cost inputs are one of the primary determinants of the simulated mix of generation fuels in UPLAN. Although the licensed LCG database includes monthly forecast values for a base simulation year for various fuel groups, EIA forecasts its own delivered fossil fuel prices for input into UPLAN to develop the STEO electricity supply forecasts.

One of the RSTEM modules forecasts monthly average fuel costs for natural gas, coal, petroleum liquids, and petroleum coke delivered to the electric power sector. Natural gas and coal fuel cost forecasts are produced for the nine census divisions. These fuel cost forecasts correspond to the historical data published in EIA's *Electric Power Monthly*.

EIA's surveyed regional natural gas costs to the electric power sector are generally well correlated with the Henry Hub natural gas price. Other variables that help determine the fuel cost forecasts are regional heating and cooling degree days. In addition, in areas of the country where many households heat with natural gas, the electric power sector natural gas fuel cost is affected by the amount of residential natural gas consumption, especially in the winter months. EIA forecasts natural gas fuel prices from econometric equations that model the difference, or basis, between the census division fuel price and the Henry Hub natural gas price:

$$\begin{aligned} NGEPU_t^D - NGHHUUS_t = {} & a_1(ZWHD_t^D - ZWHD10yr_t^D) + a_2(ZWCD_t^D - ZWCD10yr_t^D) \\ & + b_1 JAN_t + b_2 FEB_t + b_3 MAR_t \cdots + b_{10} OCT_t + b_{11} NOV_t + b_{12} DEC_t \end{aligned} \tag{4}$$

where

$NGEPU_t^D$ = average natural gas fuel cost delivered to electric power sector in census division *D*
$NGHHUUS_t$ = Henry Hub natural gas fuel price
$ZWHD_t^D$ = heating degree days for census division *D*
$ZWHD10yr_t^D$ = previous 10-year average heating degree days for census division *D*
$ZWCD_t^D$ = cooling degree days for census division *D*
$ZWCD10yr_t^D$ = previous 10-year average cooling degree days for census division *D*
$JAN_t,\ FEB_t, \ldots NOV_t, DEC_t$ = monthly dummy variables

The primary explanatory variables for the regional coal fuel cost equations are the U.S. composite spot price of coal, electric power sector coal stocks, and the cost of diesel fuel for transportation.

$$CLEPU_t^D = a_0 + b_1 CLSPUUS_t + b_2 CLPS\_EP_t + b_3 DSRTUUS_t \tag{5}$$

where

$CLEPU_t^D$ = average U.S. cost of coal delivered to electric power sector in census division *D*
$CLSPUUS_t$ = average U.S. composite coal spot price
$CLPS\_EP_t$ = end-of-month U.S. electric power sector coal stocks
$DSRTUUS_t$ = average U.S. diesel fuel price

RSTEM also produces forecasts for U.S. prices for petroleum liquids and petroleum coke. In addition to fossil fuel costs, UPLAN inputs are also included for the costs of biomass, landfill gases, and uranium based on data in the UPLAN database licensed from LCG.

Conventional hydroelectric forecast

EIA develops initial estimates for aggregate regional monthly hydroelectric generation outside of UPLAN. The most significant forecast is EIA's estimate of hydropower in the Pacific Northwest (i.e., Oregon and Washington), which produces nearly half of the nation's hydroelectric generation. Hydropower generation in this region is very strongly correlated with water supply output from the Dalles Dam on the Columbia River.

EIA uses the Northwest River Forecast Center's (NWRFC) water supply outlook of the Columbia River to produce an initial estimate of monthly hydropower generation for the Pacific Northwest region. The water supply forecast is given for the upcoming water year (October–September). EIA bases its hydropower forecast beyond this period on the previous 30-year average level of monthly generation. For areas of the country outside the Pacific Northwest, EIA assumes regional hydropower forecasts follow the 30-year average.

For input into UPLAN, these regional aggregate monthly estimates are converted into daily capacity factors for each hydroelectric generator in each region. UPLAN then dispatches these units each hour at the given capacity factor, with a share of the hourly generation designated to be at a constant baseload level and the remainder designated to follow the zone's hourly load profile.

Nuclear generation forecast

The primary inputs for the STEO's forecast of nuclear generation are also developed outside of RSTEM and UPLAN. Power generation by nuclear reactors is relatively predictable, with units usually operating at capacity factors of 95% or more, except when a unit is brought down for refueling and maintenance. EIA matches historical monthly generation levels from the Form EIA-923 survey with daily power level percentages as reported by the Nuclear Regulatory Commission (NRC) in its daily status reports. This matching provides an estimate of the typical maximum output for each reactor along with the average capacity factor during non-refueling periods. These average capacity factors also account for forced outages that may happen from time to time.

EIA has developed a schedule of projected refueling outages for each nuclear reactor, based on an analysis of historical refueling episodes as reported in NRC's daily status reports. EIA calculates the median number of days in refueling and the median number of months between refueling cycles from the historical NRC data. Median refueling cycles are adjusted to fit either an 18-month or 24-month interval. The typical cycle and number of days in refueling are then applied to the most recent refueling episode for each reactor.

Nuclear unit input for UPLAN includes each reactor's average monthly capacity factor along with the projected refueling schedules. The model treats nuclear generators as must-run units so that they will be committed and dispatched at the specified capacity factor (except during those days when they are taken offline for refueling and maintenance).

5. Developing STEO forecasts from UPLAN output

EIA creates STEO electricity supply forecasts for the electric power sector from information contained in the UPLAN model solution output. In some cases, such as for nuclear generation, the STEO monthly forecasts are calculated directly from the UPLAN output by summing up the simulated hourly generation for a specific fuel and region. In most cases, however, EIA integrates the UPLAN output into RSTEM, which develops the STEO forecasts by analyzing the year-over-year changes in the simulated UPLAN output and applying these changes to historical data.

EIA implements this methodology for creating the STEO forecast using UPLAN output by first developing a base case scenario in UPLAN that represents a simulation of the previous historical year. In some cases, EIA may calibrate this baseline scenario by adjusting the generator dispatch offers so that the simulated patterns of generation and wholesale prices in each interconnection match the historical data as closely as possible.

RSTEM incorporates the results from this base case scenario and compares them with the results from simulated scenarios for the forecast years. Simulated forecast scenarios include the same generator information as the base case historical scenario (including information on future capacity additions/retirements), but also reflect the input data for load, fuel costs, hydroelectric output, and nuclear outages for that particular forecast year.

The model 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. EIA uses variations on this methodology to create the forecasts for electricity generation, fuel consumption, and wholesale power prices.

Electric Power Sector Generation Forecasts

RSTEM models electricity generation by fuel in the electric power sector using shares of total generation to ensure that estimates of component values sum to the estimated total. In addition, the use of generation shares tends to reduce volatility in year-to-year changes, compared with using absolute changes or percentage growth. RSTEM 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.

Total continental U.S. electric power sector generation is defined in RSTEM to be equal to the total continental U.S. load as calculated in equation (1). EIA assumes no unserved load exists. Although DC links exist between the three North American interconnections, allowing small amounts of electricity to flow between them, EIA assumes for modeling purposes that the total generation in each interconnection is equal to its load and no power flows outside the interconnection. The RSTEM model has econometric equations to 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.

Within each interconnection, electricity generation produced in one region is made available to meet the load in another 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 RSTEM model by applying the year-over-year change in the region-to-interconnection generation shares from the UPLAN simulation output:

$$TOEPGEN_t^r = TOEPGEN_t^I \times \left[\frac{TOEPGEN_{t-12}^r}{TOEPGEN_{t-12}^I} + \left(\frac{toupgen_t^r}{toupgen_t^I} - \frac{toupgen_{t-12}^r}{toupgen_{t-12}^I}\right)\right] \tag{6}$$

where

$TOEPGEN_t^r$ = total electric power sector generation in region *r*
$TOEPGEN_t^I$ = total electric power sector generation in interconnection *I*
$toupgen_t^r$ = total UPLAN simulated generation in region *r*
$toupgen_t^I$ = total UPLAN simulated generation in interconnection *I*

These calculations are not necessary for the ERCOT market because it is the only STEO modeling region in the Texas Interconnection, or $TOEPGEN_t^r = TOEPGEN_t^I$.

The forecast amount of generation for each fuel within the STEO modeling regions is determined in a similar way—by applying year-over-year changes in the fuel's share of total regional generation from the UPLAN simulation. The RSTEM model equation specification for applying the year-over-year changes in UPLAN generation share can be stated as in the following example for natural gas:

$$NGEPGEN_t^r = TOEPGEN_t^r \times \left[\frac{NGEPGEN_{t-12}^r}{TOEPGEN_{t-12}^r} + \left(\frac{ngupgen_t^r}{toupgen_t^r} - \frac{ngupgen_{t-12}^r}{toupgen_{t-12}^r}\right)\right] \tag{7}$$

where

$NGEPGEN_t^r$ = natural gas-fired electric power sector generation in region *r*
$TOEPGEN_t^r$ = total electric power sector generation in region *r*
$ngupgen_t^r$ = UPLAN simulated natural generation in region *r*
$toupgen_t^r$ = total UPLAN simulated generation in region *r*

The RSTEM model includes similar equations to calculate forecast generation for all of the STEO fuel codes listed in Table 2. Because EIA structures the fuel generation equations using generation shares in RSTEM, the sum of the generation values are equal to the total regional generation forecasts from equation (6).

Electric Power Sector Fuel Consumption Forecasts

The consumption of fossil fuels for electricity generation depends on both the amount of generation produced and the heat rate of the generating units that are dispatched. The UPLAN model allows each generator to have heat rates that can vary depending on the blocks of capacity that are dispatched by the model simulation. For natural gas and coal, RSTEM calculates modeled consumption by multiplying the modeled generation from equation (7) by the heat rate from the same month in the previous year, adjusted by how the simulated aggregate heat rate in UPLAN has changed from the previous year. Using natural gas as an example

$$NGEPCON_t^r = NGEPGEN_t^r \times \left(\frac{NGEPCON_{t-12}^r}{NGEPGEN_{t-12}^r}\right) \times \left[\left(\frac{ngupcon_t^r}{ngupgen_t^r}\right) \div \left(\frac{ngupcon_{t-12}^r}{ngupgen_{t-12}^r}\right)\right] \qquad (8)$$

where

$NGEPCON_t^r$ = consumption of natural gas by electric power sector in region *r* during month *t*
$NGEPGEN_t^r$ = natural gas-fired electric power sector generation in region *r* during month *t*
$ngupcon_t^r$ = UPLAN simulated natural gas consumption in region *r* during month *t*
$ngupgen_t^r$ = UPLAN simulated natural gas generation in region *r* during month *t*

The amount of petroleum liquids consumed for electric generation is relatively small compared with that of coal or natural gas. The RSTEM model calculates the consumption of petroleum fuels using a simpler identity that relates modeled consumption to modeled generation and the average heat rate over the previous 12 months.

$$DKEPCON_t^r = DKEPGEN_t^r \times \left[\sum_{n=1}^{12} \left(\frac{DKEPCON_{t-n}^r}{DKEPGEN_{t-n}^r}\right) \div 12\right] \qquad (9)$$

where

$DKEPCON_t^r$ = consumption of distillate fuel by electric power sector in region *r* during month *t*
$DKEPGEN_t^r$ = distillate generation by electric power sector in region *r* during month *t*

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, EIA assumes that the forecast level of consumption is zero.

Wholesale Electricity Price Forecasts

LMPs are some of the primary output of the UPLAN electricity model, providing the value of electricity at certain locations and reflecting generation and load patterns along with transmission system limits. The zonal version of UPLAN produces LMPs for each of the 125 zones within the model. Instead of reporting all of these zonal results in the regular STEO publication, EIA reports a representative wholesale price for each STEO supply region. RSTEM bases the forecast values for these wholesale prices on one or more of the zonal LMPs within that region, as shown in Table 4. Some STEO supply regions use the LMP from a single zone as the representative wholesale price. In other STEO regions, the wholesale price is calculated as the load-weighted average of multiple zones.

UPLAN also breaks out the LMP into energy, congestion, and loss components. The forecast wholesale price EIA publishes 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 off the year-over-year growth rates in the simulated UPLAN LMPs.

$$ELWHU_t^R = ELUPLMP_t^R \times \left(\frac{\text{med}\{ELWHU_{t-1}^R, \cdots, ELWHU_{t-13}^R\}}{\text{med}\{ELUPLMP_{t-1}^R, \cdots, ELUPLMP_{t-13}^R\}}\right) \qquad (10)$$

where

$ELWHU_t^R$ = historical or forecast locational marginal price for STEO region *R*
$ELUPLMP_t^R$ = simulated UPLAN locational marginal price for STEO region *R*

Commercial and Industrial Sector Electricity Supply Forecasts

In addition to the electric power sector, EIA publishes electricity generation and fuel consumption by the commercial and industrial sectors. Power plants operated by these two sectors are generally combined heat and power (CHP) units that provide power for use onsite and may supply excess generation to the transmission grid. EIA only produces national forecasts of generation for the commercial and industrial sectors in the STEO; regional generation forecasts are not produced. RSTEM forecasts U.S. power generation for these sectors using econometric equations. Equations for generation by fuel for the commercial and industrial sectors, for regions in which historical values are consistently non-zero, are a function of monthly dummy variables to capture seasonal generation patterns.

$$NGINGEN_t^{US} = a_1 JAN_t + a_2 FEB_t + \cdots + a_{11} NOV_t + a_{12} DEC_t \qquad (11)$$

where

$NGINGEN_t^{US} =$ U.S. natural gas generation by the industrial sector

$JAN_t,\ FEB_t, \ldots NOV_t, DEC_t =$ monthly dummy variables

In cases where the commercial and industrial sectors have zero generation by a fuel during certain months, EIA sets forecast values equal to the value in the same month from the previous historical year. The RSTEM model calculates forecast fuel consumption by multiplying forecast generation and the average historical ratio of fuel consumption and generation.

6. Changes to the STEO electricity tables

EIA has revised its presentation of electricity industry data in the STEO standard tables and associated datasets to accommodate the expanded electricity supply forecasts. The new Tables 7a, 7b, 7c, 7d, and 7e are shown below. In previous STEO publications, EIA presented electricity generation and consumption data in units of average watthours per day. Beginning with the August 2019 STEO, all electricity-related STEO tables now present data in *total* watthours during a given period (month, quarter, or year).

Table 7a continues to provide the U.S. electricity industry overview with supply and demand data displayed in new units. EIA now includes the new regional wholesale price forecasts under the Power and Fuel Prices section of this table. The retail electricity data on Tables 7b and 7c are unaffected except for the change in units on Table 7b. EIA provides generation forecasts for the new STEO electricity supply regions in Table 7d, which is a two-part table in the PDF and Excel versions. More detail about generation from specific energy sources is available in the customizable STEO table browser.

Table 7e, which previously reported fuel consumption used for electricity generation, has been discontinued from the standard list of STEO tables. EIA continues to show forecasts of U.S. fossil fuel consumption by the electric power sector on the standard tables for the individual fuels as in previous STEO editions. Regional electric power sector fuel consumption forecasts are available in the customizable STEO table browser, along with U.S. forecasts for the industrial and commercial sectors.

Table 7a. U.S. Electricity Industry Overview

U.S. Energy Information Administration | Short-Term Energy Outlook - August 2019

	2018				2019				2020				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2018	2019	2020
Electricity Supply (billion kilowatthours)															
Electricity Generation	1,001	1,014	1,177	985	994	979	1,148	970	999	981	1,136	973	4,178	4,091	4,088
Electric Power Sector (a)	962	975	1,136	945	955	941	1,109	932	960	943	1,095	933	4,018	3,936	3,931
Industrial Sector (b)	36	36	38	37	36	35	36	35	36	35	37	36	146	142	144
Commercial Sector (b)	3	3	4	3	3	3	3	3	3	3	4	3	13	13	13
Net Imports	35	35	37	36	36	34	35	34	35	34	36	35	144	140	141
Total Supply	1,013	1,025	1,190	994	1,005	992	1,164	982	1,012	995	1,151	985	4,222	4,142	4,143
Losses and Unaccounted for (c) .	58	85	73	61	56	73	76	62	52	75	66	62	277	267	256
Electricity Consumption (billion kilowatthours unless noted)															
Retail Sales	921	905	1079	897	913	885	1060	886	925	885	1049	888	3802	3744	3747
Residential Sector	369	328	434	333	362	313	423	327	370	314	418	328	1464	1424	1429
Commercial Sector	325	337	387	328	322	332	383	327	326	333	379	328	1377	1364	1366
Industrial Sector	225	238	256	234	227	238	252	230	228	237	250	230	953	948	945
Transportation Sector	2	2	2	2	2	2	2	2	2	2	2	2	8	8	7
Direct Use (d)	35	35	37	36	36	34	35	34	35	34	36	35	144	140	141
Total Consumption	956	940	1117	933	948	919	1088	920	960	920	1085	923	3946	3875	3888
Average residential electricity usage per customer (kWh)	2,754	2,446	3,240	2,481	2,668	2,308	3,121	2,409	2,697	2,290	3,047	2,394	10,920	10,505	10,428
Prices															
Power Generation Fuel Costs (dollars per million Btu)															
Coal	2.06	2.06	2.06	2.08	2.08	2.08	2.10	2.10	2.12	2.13	2.11	2.11	2.06	2.09	2.12
Natural Gas	3.96	3.09	3.23	4.05	3.71	2.68	2.31	2.67	3.43	2.71	2.71	3.18	3.54	2.78	2.97
Residual Fuel Oil	11.47	13.02	14.02	14.49	12.22	13.99	12.57	12.23	12.75	13.51	12.82	12.59	12.95	12.74	12.90
Distillate Fuel Oil	15.77	16.61	16.82	16.01	14.85	15.86	15.31	16.32	16.75	17.16	17.05	17.14	16.13	15.58	17.00
Retail Prices (cents per kilowatthour)															
Residential Sector	12.59	13.03	13.15	12.75	12.66	13.33	13.32	12.86	12.66	13.43	13.47	13.12	12.89	13.05	13.17
Commercial Sector	10.54	10.60	10.89	10.55	10.41	10.66	10.91	10.51	10.32	10.62	10.96	10.67	10.66	10.63	10.65
Industrial Sector	6.81	6.87	7.22	6.82	6.66	6.77	7.09	6.68	6.69	6.85	7.24	6.82	6.93	6.81	6.91
Wholesale Electricity Prices (dollars per megawatthour)															
ERCOT North hub	33.26	37.01	61.04	34.39	28.41	28.34	34.30	28.63	32.65	28.97	32.84	36.48	41.43	29.92	32.74
CAISO SP15 zone	35.44	27.75	74.86	51.29	50.42	23.30	35.98	37.95	41.25	36.51	38.31	41.07	47.33	36.91	39.29
ISO-NE Internal hub	65.86	36.28	43.53	54.18	47.40	27.15	35.23	40.08	52.41	34.85	34.89	41.44	49.96	37.46	40.90
NYISO Hudson Valley zone	51.52	34.24	41.86	41.95	41.77	25.68	35.05	34.36	37.93	33.85	34.26	33.99	42.39	34.21	35.01
PJM Western hub	47.43	39.73	40.06	39.40	33.79	28.54	34.40	31.79	33.87	31.76	33.76	31.72	41.66	32.13	32.78
Midcontinent ISO Illinois hub	31.22	35.88	37.23	38.30	31.44	27.81	33.65	31.68	32.66	32.23	34.13	32.00	35.66	31.14	32.76
SPP ISO South hub	26.54	28.49	29.97	36.45	29.15	27.14	33.60	31.37	31.05	30.87	35.34	31.29	30.36	30.31	32.14
SERC index, Into Southern	30.84	29.30	31.80	31.18	30.74	29.87	31.24	30.76	30.52	30.23	32.15	30.43	30.78	30.65	30.83
FRCC index, Florida Reliability	30.31	30.19	31.70	31.09	30.71	29.57	28.72	33.04	32.31	29.31	30.02	32.73	30.82	30.51	31.09
Northwest index, Mid-Columbia ..	21.80	18.37	59.99	50.93	55.74	18.55	33.92	37.29	40.44	34.00	37.07	39.94	37.77	36.37	37.86
Southwest index, Palo Verde	26.39	25.76	67.78	42.71	44.23	18.45	38.07	33.54	39.00	36.64	37.67	37.88	40.66	33.57	37.80

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

kWh = kilowatthours. Btu = British thermal units.

Prices are not adjusted for inflation.

(a) Generation supplied by power plants with capacity of at least 1 megawatt operated by electric utilities and independent power producers.

(b) Generation supplied by power plants with capacity of at least 1 megawatt operated by businesses in the commercial and industrial sectors, primarily for onsite use.

(c) Includes transmission and distribution losses, data collection time-frame differences, and estimation error.

(d) Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electrical sales or transfers to adjacent or colocated facilities for which revenue information is not available. See Table 7.6 of the EIA *Monthly Energy Review*.

Historical data sources:

(1) Electricity supply, consumption, fuel costs, and retail electricity prices: Latest data available from U.S. Energy Information Administration databases supporting the following reports: Electric Power Monthly, DOE/EIA-0226; and Electric Power Annual, DOE/EIA-0348

(2) Wholesale electricity prices (except for PJM RTO price): S&P Global Market Intelligence, SNL Energy Data

(3) PJM ISO Western Hub wholesale electricity prices: PJM Data Miner website

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 7b. U.S. Regional Electricity Retail Sales (billion kilowatthours)

U.S. Energy Information Administration | Short-Term Energy Outlook - August 2019

	2018				2019				2020				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2018	2019	2020
Residential Sector															
New England	12.6	10.1	14.1	11.1	12.5	10.1	13.4	10.9	12.7	10.2	12.8	11.0	47.8	46.9	46.7
Middle Atlantic	35.4	29.4	41.6	31.1	35.3	28.1	40.4	30.6	35.8	28.3	38.0	30.5	137.5	134.3	132.6
E. N. Central	49.7	43.7	55.5	44.4	50.0	38.9	55.2	43.8	50.0	39.6	51.9	43.7	193.3	188.0	185.2
W. N. Central	29.4	24.9	29.2	25.0	29.9	21.9	29.2	24.8	29.4	22.1	28.8	24.8	108.5	105.9	105.0
S. Atlantic	93.6	83.7	109.0	86.4	88.3	84.8	107.6	83.3	92.6	81.7	105.4	83.7	372.6	364.0	363.4
E. S. Central	33.1	27.4	36.5	28.2	30.6	25.9	35.0	26.8	32.6	25.7	35.4	26.9	125.1	118.3	120.6
W. S. Central	54.8	53.0	73.9	49.1	51.8	49.8	70.5	48.3	53.5	51.5	73.0	49.0	230.7	220.5	227.0
Mountain	21.5	23.9	33.1	21.6	23.1	22.1	32.6	21.8	23.2	23.4	32.8	22.1	100.2	99.7	101.5
Pacific contiguous	38.0	30.8	40.4	34.6	39.0	30.1	37.9	35.0	38.6	30.2	38.2	35.2	143.8	142.0	142.2
AK and HI	1.2	1.1	1.2	1.2	1.2	1.1	1.1	1.2	1.2	1.0	1.1	1.2	4.7	4.6	4.6
Total	369.3	328.0	434.4	332.6	361.7	312.8	423.0	326.5	369.6	313.7	417.5	328.1	1,464.4	1,424.1	1,428.8
Commercial Sector															
New England	12.7	12.4	14.7	12.5	12.8	12.4	14.0	12.2	12.6	12.0	13.2	11.8	52.3	51.3	49.6
Middle Atlantic	38.8	37.4	44.1	37.7	38.6	36.9	42.9	37.1	38.6	36.5	41.4	37.0	158.1	155.5	153.5
E. N. Central	44.9	45.6	51.1	44.5	44.6	43.6	51.0	44.4	44.8	43.9	49.3	44.4	186.1	183.5	182.3
W. N. Central	25.4	25.7	28.3	25.0	25.6	24.3	28.3	25.1	25.8	24.6	28.2	25.2	104.4	103.3	103.8
S. Atlantic	73.0	78.4	89.7	75.3	72.1	79.7	88.8	74.4	72.8	77.7	87.2	74.5	316.4	315.1	312.2
E. S. Central	21.7	23.0	27.2	22.1	21.0	22.6	26.9	21.9	21.5	22.6	27.0	21.9	94.0	92.5	93.1
W. S. Central	45.1	50.0	58.6	47.5	45.0	49.1	58.7	48.4	46.8	50.7	60.1	49.0	201.2	201.1	206.6
Mountain	22.4	24.5	28.4	23.2	22.7	23.8	28.3	23.4	23.0	24.8	28.4	23.7	98.5	98.1	99.9
Pacific contiguous	39.1	38.6	43.5	38.9	38.0	38.6	42.6	38.9	38.6	38.9	42.7	39.0	160.1	158.2	159.2
AK and HI	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	5.7	5.6	5.6
Total	324.5	337.1	387.0	328.2	321.7	332.4	382.9	327.3	325.7	333.0	379.1	327.9	1,376.7	1,364.2	1,365.8
Industrial Sector															
New England	3.8	3.9	4.3	4.0	3.8	3.9	4.2	4.0	3.8	3.9	4.1	3.9	16.0	15.9	15.8
Middle Atlantic	17.7	17.7	19.7	18.0	17.7	17.2	19.3	17.7	17.7	17.1	18.9	17.6	73.0	71.8	71.3
E. N. Central	44.9	47.1	48.8	45.4	44.8	45.9	47.1	44.0	44.6	45.6	45.8	43.6	186.1	181.8	179.6
W. N. Central	20.9	22.0	23.6	22.0	21.1	22.1	23.4	21.8	21.5	22.3	23.6	22.1	88.5	88.4	89.5
S. Atlantic	33.0	35.3	37.1	34.0	33.0	34.8	35.9	32.7	32.3	33.6	34.6	31.9	139.4	136.4	132.5
E. S. Central	23.1	23.8	26.4	24.0	23.4	24.0	25.8	23.4	23.1	23.3	25.3	22.8	97.3	96.7	94.5
W. S. Central	42.0	45.5	47.8	44.7	44.2	47.3	48.3	44.5	45.1	47.7	49.2	45.3	180.0	184.3	187.2
Mountain	18.8	20.8	23.1	20.2	19.2	20.8	23.3	20.2	19.5	21.2	23.4	20.5	82.8	83.6	84.7
Pacific contiguous	19.5	21.0	23.7	20.8	19.0	21.0	23.6	20.6	19.0	21.0	23.8	20.8	85.0	84.3	84.6
AK and HI	1.2	1.2	1.3	1.2	1.1	1.2	1.3	1.3	1.1	1.2	1.3	1.3	4.9	4.8	4.9
Total	224.8	238.2	255.9	234.2	227.4	238.2	252.3	230.3	227.9	236.8	250.0	229.8	953.1	948.1	944.5
Total All Sectors (a)															
New England	29.3	26.6	33.2	27.7	29.2	26.4	31.8	27.3	29.3	26.1	30.3	26.9	116.7	114.7	112.6
Middle Atlantic	93.0	85.4	106.4	87.7	92.6	83.0	103.5	86.3	93.0	82.8	99.3	86.0	372.6	365.4	361.1
E. N. Central	139.7	136.5	155.6	134.4	139.6	128.5	153.5	132.3	139.6	129.3	147.1	131.8	566.1	554.0	547.7
W. N. Central	75.7	72.6	81.2	72.0	76.7	68.4	80.9	71.7	76.6	69.0	80.6	72.1	301.4	297.7	298.3
S. Atlantic	199.8	197.8	236.1	196.0	193.7	199.7	232.7	190.7	198.0	193.3	227.6	190.5	829.8	816.8	809.4
E. S. Central	78.0	74.1	90.0	74.3	75.0	72.5	87.8	72.1	77.3	71.6	87.7	71.6	316.4	307.4	308.2
W. S. Central	141.9	148.5	180.4	141.4	141.1	146.2	177.6	141.3	145.4	149.9	182.4	143.4	612.2	606.2	621.1
Mountain	62.7	69.3	84.7	65.0	65.1	66.8	84.2	65.5	65.9	69.4	84.7	66.2	281.7	281.6	286.2
Pacific contiguous	96.7	90.6	107.8	94.5	96.2	90.0	104.4	94.8	96.4	90.3	104.9	95.2	389.7	385.4	386.9
AK and HI	3.8	3.7	3.9	3.9	3.7	3.6	3.9	3.9	3.7	3.6	3.9	3.9	15.3	15.0	15.0
Total	920.6	905.2	1,079.3	896.9	912.8	885.2	1,060.1	885.9	925.1	885.4	1,048.5	887.5	3,801.9	3,744.0	3,746.5

- = no data available

(a) Total retail sales to all sectors includes residential, commercial, industrial, and transportation sector sales.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Retail Sales represents total retail electricity sales by electric utilities and power marketers.

Regions refer to U.S. Census divisions.

See "Census division" in EIA's Energy Glossary (http://www.eia.doe.gov/glossary/index.html) for a list of States in each region.

Historical data: Latest data available from U.S. Energy Information Administration databases supporting the following reports: *Electric Power Monthly*, DOE/EIA-0226; and *Electric Power Annual*, DOE/EIA-0348.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 7c. U.S. Regional Retail Electricity Prices (Cents per Kilowatthour)

U.S. Energy Information Administration | Short-Term Energy Outlook - August 2019

	2018				2019				2020				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2018	2019	2020
Residential Sector															
New England	20.56	20.57	20.39	20.64	21.05	21.52	21.23	21.19	21.28	21.50	21.31	21.40	20.53	21.24	21.36
Middle Atlantic	15.62	16.21	16.34	15.80	15.20	16.09	16.11	15.40	14.82	15.94	16.36	15.84	16.00	15.70	15.73
E. N. Central	12.94	13.48	13.09	13.19	12.93	13.84	13.33	13.40	13.17	14.17	13.83	13.90	13.16	13.34	13.74
W. N. Central	10.90	12.63	13.10	11.39	10.71	12.94	13.36	11.68	11.08	13.39	13.93	12.16	12.00	12.12	12.60
S. Atlantic	11.66	11.90	11.82	11.62	11.71	12.12	11.91	11.67	11.57	12.04	11.88	11.75	11.75	11.85	11.81
E. S. Central	10.86	11.40	11.16	11.17	11.11	11.74	11.47	11.48	11.23	12.01	11.71	11.76	11.14	11.44	11.66
W. S. Central	10.52	11.01	10.97	10.83	10.79	11.46	11.20	10.77	10.55	11.25	11.13	10.88	10.85	11.07	10.96
Mountain	11.58	12.24	12.26	11.76	11.52	12.19	12.32	11.85	11.63	12.41	12.62	12.20	12.00	12.00	12.25
Pacific	14.88	15.27	17.07	14.77	14.86	15.81	17.46	15.03	15.19	16.35	17.88	15.33	15.55	15.80	16.19
U.S. Average	12.59	13.03	13.15	12.75	12.66	13.33	13.32	12.86	12.66	13.43	13.47	13.12	12.89	13.05	13.17
Commercial Sector															
New England	16.59	15.92	16.19	16.44	16.72	16.16	16.45	16.61	16.77	16.14	16.50	16.80	16.28	16.49	16.56
Middle Atlantic	12.10	12.22	13.17	12.08	11.56	12.20	12.93	11.64	11.10	11.90	12.86	11.80	12.42	12.11	11.93
E. N. Central	10.10	10.15	10.08	10.10	10.14	10.26	10.16	10.10	10.13	10.31	10.33	10.33	10.11	10.16	10.28
W. N. Central	9.18	10.03	10.38	9.23	8.97	10.07	10.44	9.33	9.16	10.39	10.90	9.76	9.73	9.72	10.07
S. Atlantic	9.61	9.30	9.18	9.41	9.45	9.37	9.21	9.36	9.31	9.23	9.12	9.37	9.36	9.34	9.25
E. S. Central	10.51	10.48	10.34	10.54	10.71	10.71	10.55	10.73	10.88	10.94	10.80	11.03	10.46	10.67	10.91
W. S. Central	8.37	8.17	8.12	7.94	8.15	8.15	7.97	7.69	7.87	7.97	7.93	7.75	8.15	7.98	7.88
Mountain	9.27	9.88	10.01	9.36	9.20	9.64	9.92	9.31	9.19	9.70	10.06	9.51	9.66	9.54	9.64
Pacific	12.91	14.02	15.81	14.10	12.99	14.14	16.21	14.45	13.19	14.28	16.39	14.75	14.25	14.50	14.70
U.S. Average	10.54	10.60	10.89	10.55	10.41	10.66	10.91	10.51	10.32	10.62	10.96	10.67	10.66	10.63	10.65
Industrial Sector															
New England	13.46	12.60	12.83	12.98	13.31	12.62	12.55	12.67	13.28	12.63	12.70	12.84	12.96	12.78	12.86
Middle Atlantic	7.26	6.82	6.86	6.79	6.73	6.58	6.47	6.36	6.59	6.52	6.52	6.43	6.93	6.54	6.51
E. N. Central	7.10	6.96	6.99	7.01	7.02	6.90	6.89	6.90	7.07	7.00	7.04	7.06	7.01	6.93	7.04
W. N. Central	7.04	7.38	7.99	6.93	7.13	7.38	8.17	7.11	7.35	7.61	8.43	7.34	7.35	7.46	7.70
S. Atlantic	6.54	6.40	6.60	6.39	6.22	6.30	6.42	6.18	6.16	6.28	6.47	6.24	6.48	6.28	6.29
E. S. Central	5.74	5.92	5.87	5.88	5.71	5.86	5.74	5.74	5.71	5.90	5.82	5.83	5.86	5.76	5.81
W. S. Central	5.42	5.41	5.65	5.27	5.25	5.31	5.44	5.03	5.24	5.37	5.55	5.14	5.44	5.26	5.33
Mountain	6.10	6.48	6.93	6.05	6.13	6.24	6.70	5.91	6.13	6.28	6.80	6.00	6.41	6.26	6.32
Pacific	8.63	9.52	11.17	9.89	8.68	9.57	11.29	10.01	8.91	9.87	11.66	10.34	9.87	9.96	10.27
U.S. Average	6.81	6.87	7.22	6.82	6.66	6.77	7.09	6.68	6.69	6.85	7.24	6.82	6.93	6.81	6.91
All Sectors (a)															
New England	17.86	17.16	17.49	17.58	18.11	17.65	17.91	17.82	18.24	17.67	17.98	18.06	17.53	17.88	17.99
Middle Atlantic	12.50	12.47	13.23	12.30	12.01	12.34	12.95	11.89	11.67	12.16	12.99	12.13	12.65	12.32	12.25
E. N. Central	10.14	10.11	10.18	10.07	10.13	10.14	10.29	10.12	10.24	10.32	10.53	10.43	10.13	10.18	10.38
W. N. Central	9.26	10.12	10.66	9.27	9.14	10.12	10.83	9.46	9.39	10.45	11.26	9.84	9.85	9.90	10.25
S. Atlantic	10.06	9.88	9.99	9.86	9.92	10.00	10.03	9.82	9.85	9.90	9.99	9.89	9.95	9.95	9.91
E. S. Central	9.25	9.36	9.36	9.27	9.31	9.47	9.50	9.39	9.48	9.68	9.74	9.65	9.31	9.42	9.64
W. S. Central	8.33	8.34	8.63	8.10	8.21	8.36	8.57	7.90	8.04	8.27	8.57	7.99	8.37	8.28	8.24
Mountain	9.12	9.68	10.05	9.13	9.12	9.42	9.96	9.11	9.14	9.57	10.15	9.32	9.54	9.44	9.59
Pacific	12.81	13.39	15.25	13.40	12.88	13.62	15.53	13.68	13.13	13.93	15.85	13.99	13.76	13.97	14.27
U.S. Average	10.45	10.50	10.93	10.39	10.36	10.56	10.96	10.38	10.36	10.61	11.07	10.58	10.58	10.58	10.67

- = no data available

Prices are not adjusted for inflation.

(a) Volume-w eighted average of retail prices to residential, commercial, industrial, and transportation sectors.

Notes: The approximate break betw een historical and forecast values is show n w ith historical data printed in bold; estimates and forecasts in italics.

Regions refer to U.S. Census divisions.

See "Census division" in EIA's Energy Glossary (http://w w w .eia.doe.gov/glossary/index.html) for a list of States in each region.

Historical data: Latest data available from Energy Information Administration databases supporting the follow ing reports: *Electric Power Monthly* , DOE/EIA-0226; and *Electric Power Annual* , DOE/EIA-0348.

Minor discrepancies w ith published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 7d part 1. U.S. Regional Electricity Generation, Electric Power Sector (billion kilowatthours), *continues on Table 7d part 2*

U.S. Energy Information Administration | Short-Term Energy Outlook - August 2019

	2018				2019				2020				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2018	2019	2020
United States															
Natural Gas	286.4	321.7	445.4	312.1	316.1	329.6	464.9	339.6	306.3	345.5	448.2	322.9	1,365.7	1,450.1	1,423.0
Coal	279.3	258.3	325.5	275.5	257.7	213.6	272.8	220.0	255.0	190.5	262.7	226.8	1,138.5	964.1	934.9
Nuclear	206.5	196.1	209.5	195.0	203.5	193.9	207.3	200.7	205.9	185.1	202.5	198.0	807.1	805.5	791.5
Renewable Energy Sources:	179.9	192.8	149.5	156.7	170.9	199.3	158.0	163.9	185.3	214.1	173.5	178.2	678.7	692.1	751.2
Conventional Hydropower	76.7	85.4	63.7	64.3	71.6	82.0	64.3	63.0	72.2	80.6	67.1	63.5	290.1	281.0	283.4
Wind	78.2	74.7	53.5	68.4	74.2	83.2	60.8	77.1	85.2	94.8	67.7	87.2	274.7	295.3	334.9
Solar (a)	12.6	20.9	20.2	12.2	13.4	22.8	22.4	13.9	16.5	27.3	28.2	17.4	65.9	72.6	89.5
Biomass	8.3	7.7	7.9	7.6	7.5	7.2	6.4	5.7	7.1	7.5	6.4	6.0	31.4	26.8	26.9
Geothermal	4.1	4.0	4.3	4.2	4.1	4.1	4.1	4.2	4.3	3.9	4.1	4.1	16.7	16.5	16.5
Pumped Storage Hydropower	-1.4	-1.2	-2.0	-1.4	-1.1	-0.9	-2.2	-1.4	-1.2	-0.8	-2.0	-1.3	-5.9	-5.5	-5.3
Petroleum (b)	8.8	4.5	5.3	4.5	4.8	4.5	5.6	4.5	4.9	4.4	5.5	4.5	23.1	19.3	19.4
Other Gases	1.0	1.0	1.1	0.9	1.1	1.0	1.1	1.0	1.1	1.2	1.1	0.9	4.0	4.3	4.3
Other Nonrenewable Fuels (c)	1.8	1.8	1.5	1.9	1.7	1.8	1.6	1.9	1.7	1.8	1.5	1.8	7.0	7.0	6.7
Total Generation	962.3	975.0	1,135.7	945.2	954.6	943.2	1,111.3	931.7	960.4	942.6	1,095.0	933.2	4,018.3	3,940.8	3,931.1
New England (ISO-NE)															
Natural Gas	10.4	10.0	16.3	11.4	10.7	10.3	17.3	12.6	11.7	11.9	15.5	11.5	48.1	50.8	50.5
Coal	0.6	0.2	0.1	0.2	0.3	0.0	0.1	0.2	0.3	0.0	0.1	0.2	1.1	0.6	0.6
Nuclear	8.2	8.3	8.4	6.5	8.6	6.7	7.3	7.3	7.1	5.4	7.3	6.4	31.4	29.9	26.2
Conventional hydropower	1.8	1.9	1.8	2.2	2.3	2.0	1.8	2.0	2.1	1.8	1.7	1.9	7.8	8.2	7.5
Nonhydro renewables (d)	2.8	2.6	2.6	2.6	2.7	2.8	2.6	2.5	2.9	2.9	2.6	2.6	10.7	10.6	10.9
Other energy sources (e)	1.3	0.4	0.3	0.3	0.3	0.4	0.5	0.5	0.4	0.5	0.4	0.4	2.3	1.7	1.7
Total generation	25.1	23.4	29.6	23.3	24.8	22.2	29.5	25.2	24.4	22.5	27.5	23.0	101.3	101.7	97.5
Net energy for load (f)	30.2	27.2	34.5	28.9	29.7	26.0	33.1	28.4	30.3	27.4	31.9	28.4	120.8	117.2	118.0
New York (NYISO)															
Natural Gas	10.8	12.6	19.3	12.7	11.9	11.4	17.0	12.4	11.7	16.4	21.0	15.6	55.4	52.8	64.7
Coal	0.4	0.0	0.2	0.1	0.3	0.0	0.1	0.1	0.2	0.0	0.0	0.1	0.7	0.5	0.3
Nuclear	10.9	10.0	10.5	11.4	10.4	10.7	11.3	11.6	11.3	8.3	8.7	9.2	42.9	44.0	37.5
Conventional hydropower	7.4	7.8	7.6	8.1	7.7	7.7	7.6	7.2	7.2	7.1	7.2	7.0	30.8	30.2	28.5
Nonhydro renewables (d)	1.8	1.7	1.5	1.6	1.7	1.8	1.6	1.7	1.7	2.0	1.7	1.9	6.6	6.8	7.3
Other energy sources (e)	1.3	0.2	0.1	0.1	0.4	0.1	0.3	0.2	0.5	0.2	0.3	0.2	1.8	1.0	1.1
Total generation	32.6	32.3	39.3	34.0	32.5	31.8	37.8	33.1	32.5	33.9	38.9	34.1	138.2	135.2	139.4
Net energy for load (f)	38.2	36.5	46.1	36.9	37.7	34.8	44.4	36.6	38.1	36.2	43.0	36.7	157.7	153.4	154.0
Mid-Atlantic (PJM)															
Natural Gas	54.6	56.6	78.4	60.3	68.5	63.2	88.4	73.5	68.2	74.5	91.6	73.5	249.9	293.6	307.9
Coal	61.8	51.6	62.4	50.7	53.3	42.3	51.2	43.2	59.5	25.5	39.4	43.0	226.6	190.0	167.3
Nuclear	71.7	69.2	73.2	71.3	69.6	67.8	70.3	67.7	70.0	65.3	67.7	68.0	285.4	275.4	271.0
Conventional hydropower	2.4	2.7	2.6	3.4	3.3	2.8	2.6	3.0	3.0	2.5	2.4	2.9	11.2	11.7	10.9
Nonhydro renewables (d)	9.7	8.3	6.9	8.6	9.4	9.5	7.5	9.2	9.9	10.3	7.9	10.0	33.6	35.6	38.0
Other energy sources (e)	1.9	0.5	0.4	0.7	0.7	0.8	1.3	1.1	1.2	1.1	1.2	1.1	3.4	3.9	4.7
Total generation	202.1	188.9	223.9	195.1	204.8	183.9	219.0	197.8	211.8	179.2	210.2	198.7	810.1	805.5	799.9
Net energy for load (f)	199.9	184.3	217.1	188.0	197.0	175.4	209.0	181.9	198.0	175.3	204.1	182.2	789.4	763.3	759.6
Southeast (SERC)															
Natural Gas	55.7	59.0	76.1	55.7	56.0	59.6	74.5	58.9	61.2	65.4	72.7	58.4	246.5	249.0	257.7
Coal	44.3	45.0	53.9	42.3	35.1	40.6	48.7	31.1	36.2	36.0	46.5	31.8	185.5	155.6	150.5
Nuclear	52.0	50.7	53.5	48.5	52.3	51.9	54.3	53.2	52.0	49.4	54.1	53.0	204.8	211.8	208.5
Conventional hydropower	7.4	8.2	7.6	10.5	10.5	8.7	7.7	9.1	9.5	7.7	7.0	8.9	33.7	35.9	33.2
Nonhydro renewables (d)	2.7	3.8	3.7	2.5	2.8	4.0	3.9	2.4	3.2	5.5	5.5	3.2	12.7	13.2	17.5
Other energy sources (e)	0.4	-0.1	-0.5	-0.1	0.0	0.0	0.2	0.2	0.3	0.2	0.2	0.2	-0.3	0.5	0.9
Total generation	162.5	166.6	194.3	159.4	156.7	164.8	189.2	155.1	162.4	164.3	186.0	155.5	682.9	665.9	668.2
Net energy for load (f)	165.2	165.4	191.9	158.9	160.1	161.1	187.1	156.7	165.8	158.0	183.8	156.0	681.4	665.1	663.5
Florida (FRCC)															
Natural Gas	34.0	41.8	50.6	39.2	35.5	45.6	51.4	29.3	31.2	40.1	49.1	30.4	165.5	161.7	150.9
Coal	6.3	6.7	7.8	6.1	3.7	4.9	5.4	9.8	7.2	4.9	5.6	8.0	26.9	23.9	25.7
Nuclear	7.5	7.7	7.0	7.1	7.6	6.4	7.3	7.5	7.2	6.7	7.4	7.8	29.3	28.8	29.1
Conventional hydropower	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Nonhydro renewables (d)	1.3	1.3	1.3	1.3	1.5	1.7	1.4	1.4	1.9	2.3	2.1	1.8	5.2	6.0	8.0
Other energy sources (e)	1.0	0.8	1.1	0.7	0.8	0.9	1.1	0.6	0.8	0.8	1.1	0.6	3.5	3.3	3.2
Total generation	50.2	58.4	67.9	54.3	49.2	59.5	66.7	48.5	48.4	54.8	65.3	48.7	230.7	223.9	217.2
Net energy for load (f)	49.5	59.1	68.5	54.0	48.5	61.6	66.8	51.7	48.7	57.4	65.8	51.8	231.0	228.6	223.7

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Data reflect generation supplied by power plants with a combined capacity of at least 1 megawatt operated by electric utilities and independent power producers.

(a) Large-scale solar generation from power plants with more than 1 megawatt of capacity. Excludes generation from small-scale solar photovoltaic systems.

(b) Residual fuel oil, distillate fuel oil, petroleum coke, and other petroleum liquids.

(c) Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, nonrenewable waste, and miscellaneous technologies.

(d) Wind, large-scale solar, biomass, and geothermal

(e) Pumped storage hydroelectric, petroleum, other gases, batteries, and other nonrenewable fuels. See notes (b) and (c).

(f) Regional generation from generating units operated by electric power sector, plus energy receipts from minus energy deliveries to U.S. balancing authorities outside region.

Historical data: Latest data available from U.S. Energy Information Administration databases supporting the following reports: *Electric Power Monthly*, DOE/EIA-0226;

Projections: EIA Regional Short-Term Energy Model.

Table 7d part 2. U.S. Regional Electricity Generation, Electric Power Sector (billion kilowatthours), *continued from Table 7d part 1*

U.S. Energy Information Administration | Short-Term Energy Outlook - August 2019

	2018				2019				2020				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2018	2019	2020
Midcontinent ISO (MISO)															
Natural Gas	34.0	41.7	49.4	30.7	35.1	39.7	54.1	42.9	34.3	44.1	52.3	38.7	155.8	171.8	169.4
Coal	82.5	77.8	93.6	80.7	77.5	62.4	77.8	60.6	71.7	60.8	75.1	61.4	334.6	278.3	268.9
Nuclear	26.4	22.9	25.7	23.3	25.3	22.7	26.5	25.8	26.9	22.3	26.8	24.9	98.3	100.2	100.9
Conventional hydropower	2.7	2.8	2.1	2.3	2.5	2.7	2.2	2.1	2.3	2.4	2.0	2.0	10.0	9.4	8.7
Nonhydro renewables (d)	18.1	15.0	11.9	16.0	17.1	17.4	13.3	17.8	20.2	20.7	16.1	21.2	60.9	65.6	78.2
Other energy sources (e)	2.0	1.7	1.9	1.7	1.9	1.7	2.5	2.2	2.2	2.1	2.5	1.9	7.2	8.3	8.6
Total generation	165.8	161.8	184.6	154.7	159.4	146.6	176.3	151.3	157.5	152.3	174.7	150.1	666.8	633.6	634.7
Net energy for load (f)	162.0	163.4	184.8	158.9	161.1	153.6	181.3	158.0	162.4	156.8	177.3	157.3	669.1	654.0	653.8
Southwest Power Pool (SPP)															
Natural Gas	11.9	18.1	22.5	12.6	13.3	15.6	23.5	16.9	16.3	16.8	21.4	15.4	65.0	69.4	69.9
Coal	27.9	24.5	34.2	27.3	27.3	18.5	29.7	18.5	21.6	15.9	30.2	17.7	113.8	93.9	85.5
Nuclear	4.2	2.8	4.3	3.5	4.4	4.3	4.3	2.5	4.1	4.2	4.4	3.6	14.8	15.6	16.3
Conventional hydropower	4.0	4.3	3.1	3.6	3.8	4.1	3.2	3.1	3.4	3.6	2.9	3.0	14.9	14.2	13.0
Nonhydro renewables (d)	18.7	18.5	13.1	16.6	18.1	20.2	15.4	19.4	21.1	23.0	16.5	21.1	66.9	73.1	81.8
Other energy sources (e)	0.2	0.2	0.1	0.2	0.2	0.3	0.2	0.2	0.2	0.1	0.2	0.2	0.8	0.9	0.7
Total generation	66.9	68.3	77.3	63.7	67.1	63.1	76.2	60.6	66.8	63.6	75.5	61.1	276.2	267.0	267.0
Net energy for load (f)	60.1	63.8	74.0	58.9	60.4	59.5	73.1	58.3	60.5	59.7	72.2	58.8	256.8	251.3	251.2
Texas (ERCOT)															
Natural Gas	33.6	41.2	56.9	34.3	34.0	41.6	57.9	37.8	27.7	37.2	50.8	28.7	166.1	171.3	144.4
Coal	18.6	22.0	26.4	22.6	18.1	18.1	23.1	16.0	20.6	18.9	25.9	21.7	89.6	75.4	87.1
Nuclear	10.8	10.2	10.9	9.3	10.4	9.6	10.8	10.4	11.2	8.8	11.0	10.4	41.2	41.2	41.5
Conventional hydropower	0.2	0.3	0.2	0.4	0.4	0.3	0.2	0.3	0.4	0.3	0.2	0.3	1.1	1.3	1.2
Nonhydro renewables (d)	19.4	21.9	15.0	17.5	19.5	23.7	17.3	20.1	23.4	29.3	22.5	24.4	73.7	80.5	99.5
Other energy sources (e)	0.3	0.4	0.0	0.3	0.4	0.4	0.0	0.3	0.4	0.4	0.0	0.3	1.0	1.1	1.1
Total generation	83.0	95.9	109.5	84.4	82.8	93.7	109.4	84.9	83.7	94.9	110.3	85.9	372.8	370.8	374.8
Net energy for load (f)	83.0	95.9	109.5	84.4	82.8	93.7	109.4	84.9	83.7	94.9	110.3	85.9	372.8	370.8	374.8
Northwest and Rockies															
Natural Gas	17.4	16.2	28.7	19.4	20.9	16.4	32.8	20.8	13.3	15.1	27.7	16.3	81.7	90.9	72.3
Coal	25.2	20.0	30.8	30.5	29.7	17.9	25.5	27.0	28.8	19.9	29.9	31.4	106.6	100.0	110.0
Nuclear	2.5	2.1	2.5	2.5	2.5	1.3	2.3	2.5	2.5	2.3	2.3	2.5	9.7	8.6	9.6
Conventional hydropower	43.6	45.2	27.9	27.6	30.9	38.4	28.3	30.7	34.3	41.2	33.6	32.1	144.3	128.3	141.1
Nonhydro renewables (d)	12.5	12.7	10.7	10.6	10.6	13.5	11.5	11.1	11.6	14.0	11.6	12.6	46.5	46.7	49.8
Other energy sources (e)	0.2	0.2	0.3	0.2	0.2	0.2	0.4	0.3	0.2	0.3	0.4	0.3	1.0	1.1	1.2
Total generation	101.5	96.5	101.0	90.9	94.7	87.7	100.9	92.4	90.7	92.7	105.6	95.1	389.8	375.6	384.1
Net energy for load (f)	88.9	82.7	91.6	86.3	90.9	81.7	90.5	85.8	87.5	82.1	91.0	86.2	349.5	348.8	346.8
Southwest															
Natural Gas	6.1	10.9	18.2	12.2	10.5	12.8	21.3	12.9	8.3	10.6	21.7	14.2	47.4	57.6	54.8
Coal	9.3	8.9	12.9	11.7	9.7	7.1	8.8	10.6	6.9	6.7	6.9	8.2	42.9	36.3	28.6
Nuclear	8.5	7.3	8.5	6.8	8.6	7.5	8.6	7.8	8.7	7.4	8.6	7.7	31.1	32.5	32.4
Conventional hydropower	2.9	4.0	3.6	2.4	3.0	4.3	3.7	1.9	2.8	3.8	3.4	1.9	13.0	13.0	11.9
Nonhydro renewables (d)	2.1	2.8	2.3	2.0	2.1	2.9	2.5	2.2	2.5	3.1	2.6	2.4	9.1	9.7	10.5
Other energy sources (e)	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Total generation	28.9	34.0	45.6	35.1	33.9	34.7	45.0	35.5	29.1	31.6	43.2	34.4	143.5	149.1	138.3
Net energy for load (f)	22.5	28.8	35.3	23.6	23.2	26.3	34.8	23.6	22.8	27.6	35.0	23.7	110.2	107.9	109.1
California															
Natural Gas	17.1	13.1	27.9	23.0	18.6	12.8	26.0	20.9	21.6	12.7	23.8	19.4	81.0	78.3	77.5
Coal	1.9	1.3	2.5	2.8	2.2	1.3	2.0	2.4	1.7	1.5	2.6	2.8	8.5	7.8	8.6
Nuclear	3.7	4.9	4.9	4.7	3.8	4.9	4.4	4.4	4.8	4.9	4.3	4.4	18.2	17.5	18.5
Conventional hydropower	3.8	7.6	6.7	3.3	7.0	10.6	6.6	2.9	6.8	9.8	6.2	2.9	21.4	27.2	25.7
Nonhydro renewables (d)	13.8	18.3	16.4	12.8	13.6	19.4	16.2	12.7	14.4	20.1	16.8	13.2	61.3	61.8	64.5
Other energy sources (e)	0.0	0.1	0.1	-0.1	-0.2	0.2	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.1	0.2
Total generation	40.2	45.3	58.6	46.6	45.0	49.0	55.2	43.3	49.4	49.0	53.9	42.7	190.6	192.6	195.1
Net energy for load (f)	59.1	64.2	78.3	62.7	59.5	63.4	75.8	61.9	58.9	63.6	76.7	62.3	264.3	260.6	261.7

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Data reflect generation supplied by power plants with a combined capacity of at least 1 megawatt operated by electric utilities and independent power producers.

(a) Large-scale solar generation from power plants with more than 1 megawatt of capacity. Excludes generation from small-scale solar photovoltaic systems.

(b) Residual fuel oil, distillate fuel oil, petroleum coke, and other petroleum liquids.

(c) Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, nonrenewable waste, and miscellaneous technologies.

(d) Wind, large-scale solar, biomass, and geothermal

(e) Pumped storage hydroelectric, petroleum, other gases, batteries, and other nonrenewable fuels. See notes (b) and (c).

(f) Regional generation from generating units operated by electric power sector, plus energy receipts from minus energy deliveries to U.S. balancing authorities outside region.

Historical data: Latest data available from U.S. Energy Information Administration databases supporting the following reports: *Electric Power Monthly*, DOE/EIA-0226;

Projections: EIA Regional Short-Term Energy Model.