Electricity Market Module of the National Energy Modeling System: Model Documentation 2025

July 2025

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Updates

This report describes the model documentation that the Electricity Market Module (EMM) used for the *Annual Energy Outlook 2025* (AEO2025). We included the following major changes from the AEO2022 version of the documentation, which cover legislation and regulation changes as well model updates:

Legislation and regulation

- Updated tax credits for new technologies based on the Inflation Reduction Act of 2022
- Added tax credit for existing nuclear plants as defined in the Inflation Reduction Act of 2022
- Incorporated updates to Section 111 of the Clean Air Act, regulating CO_2 emissions from existing coal generation and new natural gas-fired power plants based on EPA's rulings in spring 2024

Model updates

- Added hydrogen turbine and biomass with carbon capture and storage as new electricity generation technologies
- Added a retrofit option for coal-fired power plants to cofire with coal and natural gas, at fixed shares[1]
- Addressed issues on mixing fossils with renewable types in the market-sharing algorithm by setting multiple subgroups for sharing
- Updated capital costs for most utility-scale electric generating technologies
- Updated overall system load shapes load shapes and end-use specific load shapes for residential, commercial and electric vehicle demands
- Added necessary features to interface with the new Hydrogen Market Module (HMM)
- Added necessary features to interface with the new Carbon Capture, Allocation, Transportation and Storage (CCATS) Module

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[1] This feature was added primarily to reflect the compliance option for EPA's updates to Section 111, which requires a minimum of 40% natural gas cofiring. However, the option in the model remains regardless of legislation, and historically coal plants have been cofiring with natural gas during times of low natural gas prices.

1. Introduction

The National Energy Modeling System (NEMS) was developed to provide 20- to 25-year projections and analyses of energy-related activities. NEMS uses a central database to store and pass inputs and outputs between the various components. The NEMS Electricity Market Module (EMM) provides a major link in the NEMS framework (Figure 1). In each model year, EMM receives electricity demand projections from the NEMS demand modules, fuel prices from the NEMS fuel supply modules, expectations from the NEMS system module, and macroeconomic parameters from the NEMS macroeconomic module. EMM estimates the actions taken by electricity producers (electric utilities and nonutilities) to meet demand in the most economical manner. EMM then outputs electricity prices to the demand modules, fuel consumption to the fuel supply modules, emissions to the Integrating Module, and capital requirements to the macroeconomic module. The model iterates until a solution is reached for each projection year.

EMM represents:

- Capacity planning, generation, transmission, and pricing of electricity (subject to delivered prices for coal, petroleum products, natural gas, and biomass)
- Cost of centralized generation facilities
- Macroeconomic variables for costs of capital and domestic investment
- Electricity load shapes and demand

The submodules consist of capacity planning, fuel dispatching, finance and pricing, and electricity load and demand (Figure 2). In addition, the fuel dispatching and capacity planning submodules represent nonutility supply and electricity trade. NEMS demand and fuel supply modules represent nonutility generation from cogenerators and other facilities, whose primary business is not electricity generation, is represented. EMM represents all other nonutility generation. The generation of electricity is accounted for in 25 supply regions (Figure 3). EMM does not explicitly model Alaska and Hawaii, but it estimates generation and consumption projections for those states for reporting national totals.

Operating (dispatch) decisions are made by choosing the mix of plants that minimizes fuel, variable operating and maintenance (O&M), and environmental costs, subject to meeting electricity demand and environmental constraints. Capacity expansion is determined by the least-cost mix of all costs, including capital, O&M, and fuel. Electricity demand is represented by load curves, which vary by region, season, and time of day.

Because the EMM regions are based on electricity markets that do not typically follow state borders, the EMM also uses fuel regions to more directly communicate with the fuel supply modules. The EMM fuel regions (Figure 4) represent unique combinations of the Census divisions, coal demand regions and natural gas market demand regions that the different NEMS modules use to pass fuel prices, and the EMM can then map fuel consumption back at the same regional level. The EMM fuel region definitions also ensure states within a specific regional carbon policy are grouped together, if necessary.

EMM also represents distributed generation that belongs to electricity suppliers. The end-use demand modules of NEMS determine consumer-owned distributed generation, and the demand for the power sector is typically provided net of any onsite generation. However, because the end-use models cannot

accurately reflect how each distributed generation contributes to changing total load in each time slice, EMM represents distributed generation while it tries to satisfy the total end-use demand. To address this modeling requirement, EMM receives total end-use demands without removing onsite distributed generation and then dispatches both power sector and distributed generation capacity, including rooftop PV, using detailed solar resource profiles. This process allows distributed generation capacity, including the end-use PV, to affect the net load requirements at the proper times, sending more accurate signals to EMM regarding generation and capacity requirements at peak load times. The overall generation requirement for EMM is unchanged, and demand and generation reports still reflect the end-use distributed generation in the appropriate end-use sector. EMM considers construction, operating, and avoided transmission and distribution costs associated with utility-owned distributed generation to evaluate these options as an alternative to central-station capacity.

The solution to the EMM submodules is simultaneous in that, directly or indirectly, the solution for each submodule depends on the solution to every other submodule. A solution sequence through the submodules can be summarized as follows:

- The Electricity Load and Demand Submodule processes electricity demand to construct load curves.
- The Renewable Electricity Storage Submodule solves to determine the capacity factor by time slice of intermittent generation, hydroelectric plants and battery storage and the value of potential additions of battery storage.
- The Electricity Capacity Planning Submodule projects the construction of new generating plants, the retirement (if appropriate) of existing plants, the level of firm power trades, and the addition of scrubbers and other equipment for environmental compliance.
- The Electricity Fuel Dispatch Submodule dispatches the available generating units, allowing surplus capacity in selected regions to be dispatched for another region's needs (economy trade).
- The Electricity Finance and Pricing Submodule calculates electricity prices, based on both average and marginal costs.

Electricity Load and Demand Submodule

The Electricity Load and Demand (ELD) Submodule performs two major functions:

- Translate census division demand data into EMM region data, and vice versa
- Translate total electricity consumption projections into system load shapes

The demand for electricity varies during the course of a day. Electricity powers many different technologies and end uses, each requiring a different level of capacity for different lengths of time. ELD generates load curves representing the variations in the demand for electricity. For operational and planning analysis, a load duration curve, which represents the aggregated hourly demands, is constructed. Because demand varies by geographic area and time of year, the ELD submodule generates load curves for each region and season for operational purposes.

Figure 1. National Energy Modeling System

Macroeconomic Activity Module

Economic activities Energy service demands

Aggregate energy prices

Carbon Capture, Allocation, Transportation, and Sequestration Module

Regional CO_2 prices

Regional captured CO_2 quantities

International Energy Module

Imported crude and product supply curves

U.S. crude and products imports

Supply

Hydrocarbon Supply Module

Natural Gas Market Module

Coal Market Module

Renewable Fuels Module

NEMS Integrating Module

Convergence condition control

Emissions

Regional demand for energy products at a given price

Regional prices at set consumption level, short-run supply curves

Demand

Residential Demand Module

Commercial Demand Module

Industrial Demand Module

Transportation Sector Module

Delivered fuel prices, energy services, economic activity

Demand for energy fuels, technology, or efficiency choices

Optimal fuel mix Capacity expansions Electricity prices

Electricity demand Delivered fuel prices Environmental constraints

Regional demand for hydrogen and fuel prices

Regional hydrogen prices, short-run supply curves

Oil product demands Crude and HGL supply curves

Optimal capacity and supply mix of products Refinery-gate and delivered petroleum product prices Oil import quantities and prices

Conversion

Electricity Market Module

Hydrogen Market Module

Liquid Fuels Market Module

Figure 2. Electricity Market Module structure
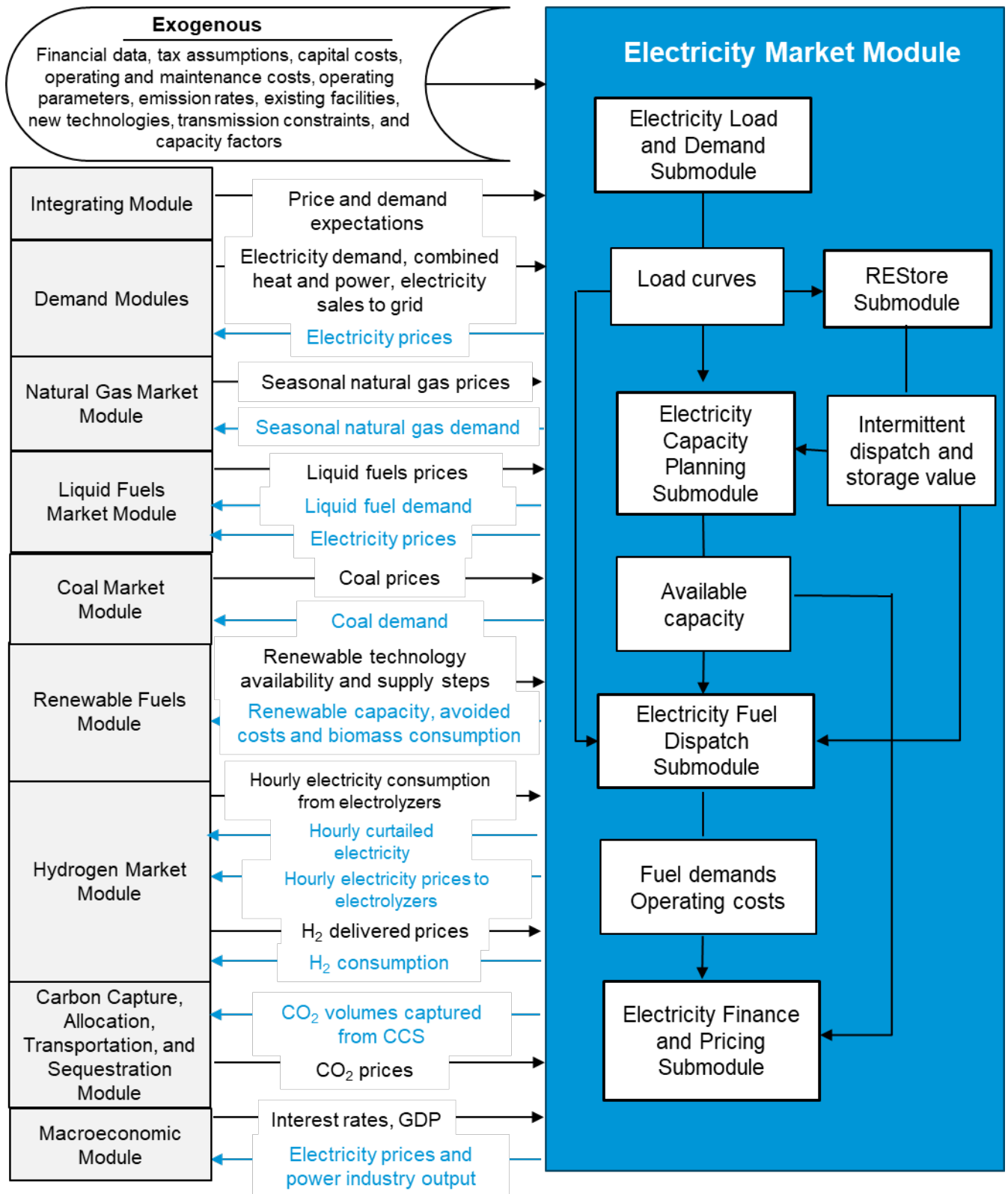
EMM Outputs	Inputs from NEMS	Exogenous Inputs
Electricity prices and price components	Electricity sales	Financial data
Fuel demands	Fuel prices	Tax assumptions
Capacity additions	Cogeneration supply and fuel consumption	Capital costs
Capital requirements	Electricity sales to the grid	Operation and maintenance costs
Emissions and captured CO_2	Renewable technology characteristics, allowable capacity, and costs	Operating parameters
Renewable capacity	Renewable capacity factors	Emissions rates
Avoided costs	Gross domestic product	New technology characteristics
	Interest rates	Existing facilities
		Transmission constraints

Figure 3. Market model supply regions
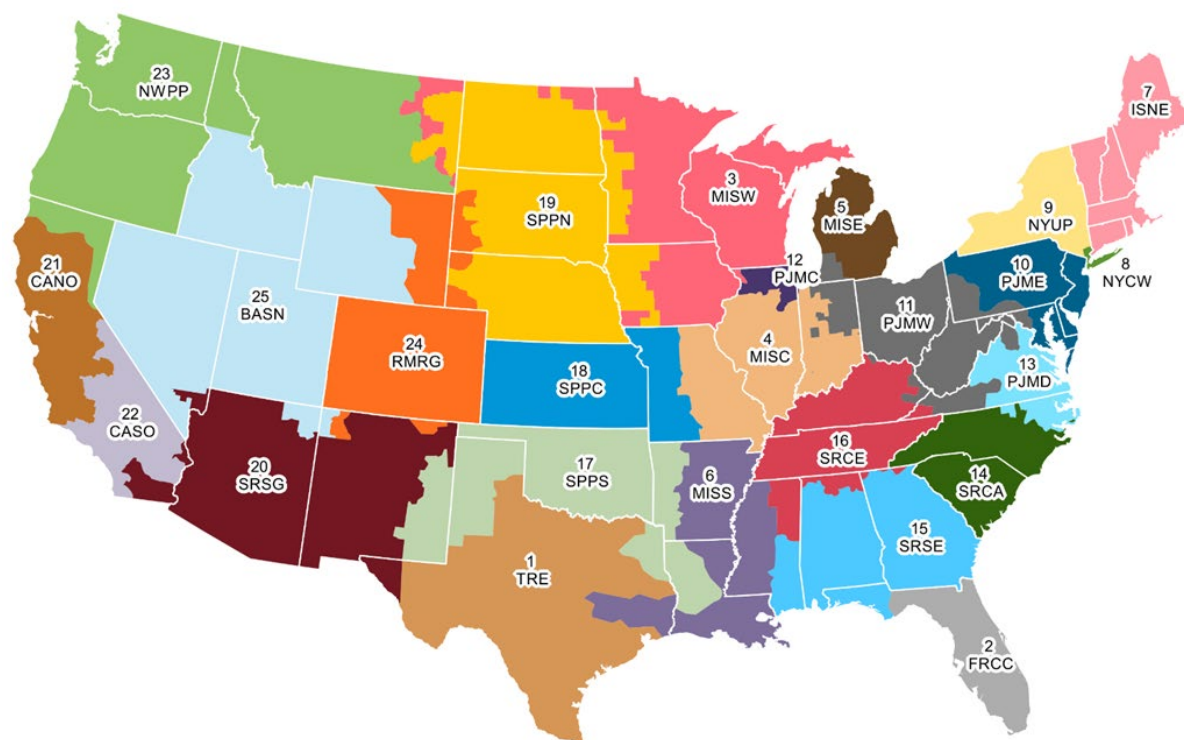
EMM Region ID	NERC/ISO subregion	EMM Region ID	NERC/ISO subregion
1- TRE	Texas Reliability Entity	14- SRCA	SERC Reliability Corporation/East
2- FRCC	Florida Reliability Coordinating Council	15- SRSE	SERC Reliability Corporation/Southeast
3- MISW	Midcontinent ISO/West	16- SRCE	SERC Reliability Corporation/Central
4- MISC	Midcontinent ISO/Central	17- SPPS	Southwest Power Pool/South
5- MISE	Midcontinent ISO/East	18- SPPC	Southwest Power Pool/Central
6- MISS	Midcontinent ISO/South	19- SPPN	Southwest Power Pool/North
7- ISNE	NPCC/ New England	20- SRSG	WECC/Southwest
8- NYCW	NPCC/NYC & Long Island	21- CANO	WECC/CA North
9- NYUP	NPCC/Upstate NY	22- CASO	WECC/CA South
10- PJME	PJM/East	23- NWPP	WECC/Northwest Power Pool
11- PJMW	PJM/West	24- RMRG	WECC/Rockies
12- PJMC	PJM/Commonwealth Edison	25- BASN	WECC/Basin
13- PJMD	PJM/Dominion		

Figure 4. Electricity Fuel Regions
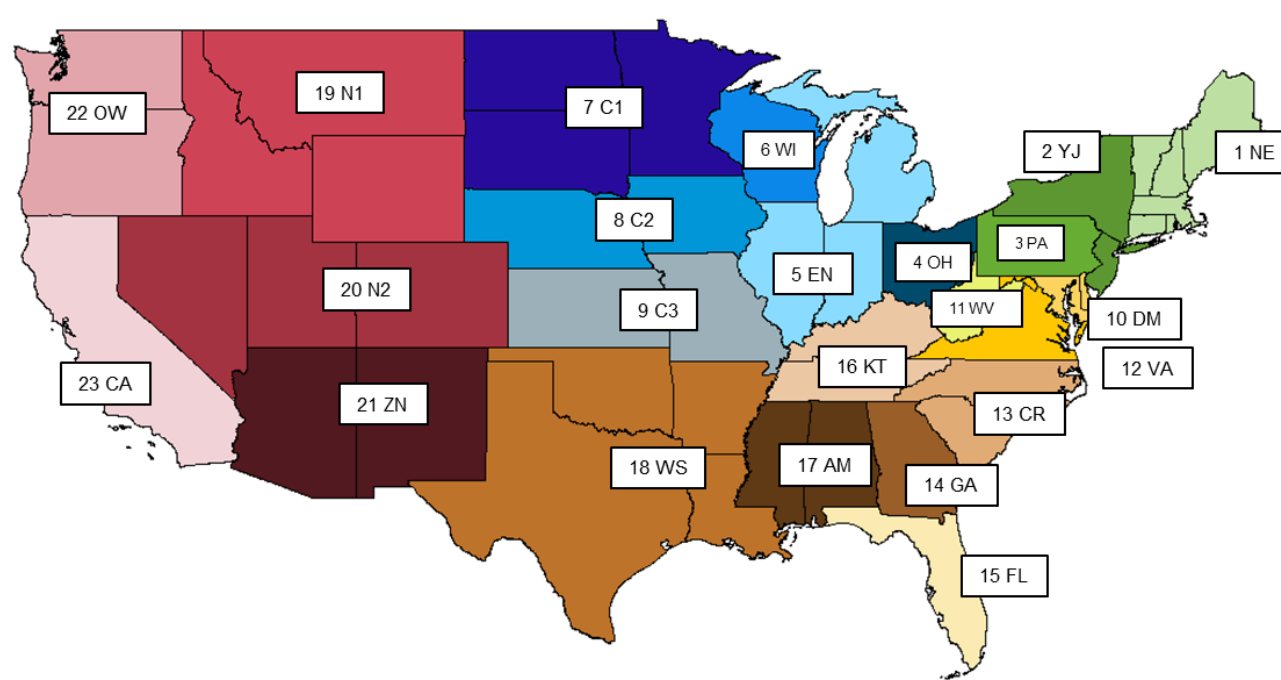
Renewable Electricity Storage Submodule (REStore)

The Renewable Electricity Storage Submodule (REStore) models the value of new energy storage capacity, dispatch of existing generation capacity, and curtailments of intermittent renewable technologies at a temporal resolution of 576 representative hours per year (12 months, 2 day types – weekday and weekend, 24 hours). EMM aggregates the hourly generation output from REStore into the nine EMM time slices to determine the generation of intermittent renewable technologies hydroelectric power, and diurnal storage by region and model year. EMM also receives the storage capacity available to provide spinning reserves by region and time slice. EMM uses the value of storage provided by REStore when making its capacity planning decisions. The Renewable Fuels Model (RFM) uses the hourly profiles provided by REStore to determine the battery storage capacity credit calculation. The Hydrogen Market Module (HMM) uses hourly electricity prices and available generation from REStore in its calculation to determine electrolyzer operation and hydrogen fuel pricing (Appendix 3.D. outlines complete REStore model documentation.)

Electricity Capacity Planning Submodule

The Electricity Capacity Planning (ECP) Submodule determines how to best meet expected growth in electricity demand, given available resources, expected load shapes, expected demands and fuel prices, environmental constraints, and technology costs and performance characteristics. When new capacity is required to meet electricity demand, the technology is chosen by the timing of the demand increase, the expected use of the new capacity, the operating efficiencies and the construction, and operating costs of available technologies.

ECP evaluates retirement decisions for fossil fuel and nuclear plants and captures responses to environmental regulations. It includes traditional and nontraditional sources of supply. ECP also

represents changes in the competitive structure (for example, deregulation). Because of competition, no distinction is made between utilities and nonutilities as owners of new capacity.

The use of the capacity is important in the decision-making process. A technology with relatively high capital costs but comparatively low operating costs (such as coal-fired technologies) may be the appropriate choice if the capacity is expected to operate continuously (base load). However, a plant type with high operating costs but low capital costs (such as a natural gas-fired turbine technology) may be the most economical selection to serve the peak load (in other words, the highest demands on the system), which occurs infrequently. The intermediate (or cycling) load occupies a middle ground between base and peak load and is best served by plants that are cheaper to build than base-load plants and cheaper to operate than peak-load plants (such as a natural gas-fired combined-cycle plant).

Technologies are compared on the basis of total capital and operating costs incurred over a 30-year period. As new technologies become available, they compete against conventional plant types. Fossil fuel, nuclear, and renewable generating technologies are represented. ECP assumes base overnight capital costs to be the current cost per kilowatt for a unit constructed today. During the AEO2025 cycle, EIA commissioned an external consultant to develop current cost estimates for utility-scale electric-generating plants.[2] Regional multipliers are applied to base overnight costs to reflect cost differences in building in different regions of the country. The regional factors from AEO2025 are based on recommendations from the cost study. An annual cost factor is calculated based on the macroeconomic variable tracking the metals and metal products in the Producer Price Index, thereby creating a link between construction costs and commodity prices. Any available tax credits, such as an investment tax credit or production tax credit, are accounted for by adjusting the capital cost or operating cost.

ECP captures uncertainty about investment costs for new technologies using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate, and the technological optimism factor declines.

Learning factors represent reductions in capital costs as a result of learning by doing.[3] Learning factors are calculated separately for each of the major design components of the technology. Generally, overnight costs for new, untested components are assumed to decrease by 20% for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. Technologies that are already commercialized are assumed to start at either the 10% or 1% learning step based on analyst judgement about their relative maturity and future learning potential.

Initially, investment decisions are determined in the ECP using cost and performance characteristics that are represented as single point estimates corresponding to the average (expected) cost. However, these parameters are also subject to uncertainty and are better represented by distributions. If the distributions of two or more options overlap, the option with the lowest average cost is not likely to capture the entire market. So, ECP uses a market-sharing algorithm to adjust the initial solution and

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[2] Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, Sargent & Lundy, January 2024.

[3] For a more detailed description, see U.S. Energy Information Administration, *NEMS Component Design Report Modeling Technology Penetration* (Washington, DC, March 1993).

reallocate some of the capacity expansion decisions to technologies that are competitive but do not have the lowest average cost.

After projecting the construction of new capacity, the submodule passes total available capacity by technology (Table 1) to the Electricity Fuel Dispatch Submodule and new capacity expenses to the Electricity Finance and Pricing Submodule.

Table 1. Summary of Electricity Market Module technologies

Fossil fuel-fired	Nuclear
Existing coal	Existing nuclear
Ultra-supercritical coal with and without sequestration	New build nuclear – multiple designs
Natural gas/oil steam	
Natural gas/oil combined cycle—multiple designs	
Combined cycle with sequestration	**Renewables**
Combustion turbine—multiple designs	Conventional hydropower
Natural gas-fired fuel cells	Geothermal
Natural gas-fired distributed generation	Solar-thermal
	Solar-photovoltaic
Other	Solar-photovoltaic battery hybrid
Hydrogen Turbine	Wind – onshore and offshore
Pumped storage hydropower	Biomass with and without sequestration
Battery storage	Municipal solid waste

Electricity Fuel Dispatch Submodule

The objective of the Electricity Fuel Dispatch (EFD) Submodule is to represent the economic, operational, and environmental considerations in electricity dispatching and trade. Given available capacity, firm power purchase agreements, fuel prices, and load curves, EFD minimizes variable costs as it solves for generation facility utilization and economy power exchanges to satisfy demand in each time period and region. EFD dispatches utility, independent power producer, and small power producer plants throughout a transmission network until demand is met. A linear programming approach allows a least-cost optimization of plants based on their operating costs and any transmission costs. Limits on emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from generating units and the engineering characteristics and maintenance requirements of units serve as constraints. The dispatch explicitly accounts for spinning reserve requirements and provides several operating options for any given plant to allow for co-optimization of the production of energy with the deployment of spinning reserves. Finally, the annual operation of plants for each region is separated into nine time periods to reflect seasonal and diurnal variation in electricity demand, using three seasons each containing three load slices.

Interregional economy trade (in other words, transactions that are not firm contracts) is also represented in the EFD. The simultaneous dispatch decision across all regions linked by transmission networks allows generation in one region to satisfy electricity demand in an adjacent region, resulting in a cost savings. Economy trade with Canada occurs in a similar manner as interregional economy trade.

Surplus Canadian energy displaces U.S. energy in an adjacent U.S. region if it results in cost savings. After dispatching, fuel use is reported back to the fuel supply modules in the regions where the fuel was consumed. Operating expenses and revenues from trade are calculated for the Electricity Finance and Pricing Submodule, with operating costs based on generation within the region and wholesale power costs calculated based on the amount of power bought or sold and the marginal price of energy at the time of the trade.

Electricity Finance and Pricing Submodule

The Electricity Finance and Pricing (EFP) Submodule tallies the costs of building capacity, buying power, and generating electricity and then uses these costs to compute both competitive and regulated end-use electricity prices. For those states that still regulate electricity generation, the EFP simulates the cost-of-service method to determine the price of electricity. The EFP submodule calculates total revenue requirements for each area of utility operation—generation, transmission, and distribution—by using:

- Historical costs for existing plants (derived from various sources such as Federal Energy Regulatory Commission (FERC) Form 1, *Annual Report of Major Electric Utilities, Licensees and Others*, and Form EIA-412, *Annual Electric Industry Financial Report*)
- Cost estimates for new plants
- Fuel prices from the NEMS fuel supply modules
- Unit operating levels
- Plant phase-in and decommissioning costs
- Purchased power costs

Revenue requirements shared over sales by customer class yield the price of electricity for each class. In addition, EFP generates detailed financial statements.

For those states that have deregulated their electricity generation markets, EFP determines competitive prices for electricity generation. Unlike cost-of-service prices, which are based on average costs, competitive prices are based on marginal costs.[4] The competitive price also includes a capacity payment, which is designed to represent a proxy for additional capital recovery that must be procured from consumers apart from modeled energy sales. While similar to capacity markets that may exist in several regions, it is not intended as a detailed representation of the various ways that markets price reliability services. The capacity payment also recovers costs associated with meeting spinning reserve requirements in the EFD. Prices for transmission and distribution are assumed to remain regulated, so the delivered electricity price under competition is the sum of the marginal price of generation and the average price of transmission and distribution.

EFP calculates the delivered price of electricity for each EMM region and passes it to the end-use demand models in NEMS. The price transmitted is either the cost-of-service price, the competitive price, or a combination of both, depending on whether a given EMM region has committed to competitive

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[4] Marginal costs are primarily the operating costs of the most expensive plant required to meet demand in a given region during a given time period.

electricity markets, what percentage of the region's sales are in competitive markets, and how long the region has been competitive.

Emissions

EMM tracks emission levels for sulfur dioxide (SO_2), nitrous oxide (NO_x), and mercury (Hg). Facility development, retrofitting, and dispatch are constrained to comply with the requirements of the Clean Air Act Amendments of 1990 (CAAA90). EMM also represents California Assembly Bill 398 (AB398) which updated and extended the California Global Warming Solutions Act of 2006 limits on carbon dioxide (CO_2) emissions; and the Regional Greenhouse Gas Initiative (RGGI), which limits CO_2 emissions from electricity generating facilities in 11 northeastern states (New Jersey reentered the program in 2019 and Virginia joined the program in 2020). Federal regulations include EPA's Mercury and Air Toxics Standards (MATS) to regulate hazardous air pollutants. EMM also incorporates EPA's Cross State Air Pollution Rule (CSAPR), which the Supreme Court upheld as a replacement for the Clean Air Interstate Rule (CAIR). The CSAPR rule regulates annual SO_2 emissions for 21 states, annual NO_x emissions for 17 states, and seasonal NO_x emissions for 22 states.

EMM includes updates to Section 111 of the Clean Air Act (CAA) as finalized by EPA in April 2024[5]. The ruling requires existing steam turbines at coal-fired power plants to either convert to a natural gas-fired steam unit or cofire with at least 40% natural gas by 2030 if the units are intended to retire by January 1, 2039, or they must be retrofitted with a carbon capture and sequestration (CCS) system with a 90% capture rate by 2032 if they are intended to operate beyond January 1, 2039. AEO2025 represents these requirements for existing coal plants, allowing the model to make economic decisions regarding conversion fully to natural gas-fired operation, conversion to cofire with natural gas, or retrofit with a CCS system by the appropriate deadlines.

EPA also revised carbon pollution standards for new, modified, and reconstructed power plants under CAA Section 111(b). The emission rate for newly constructed coal steam units maintains the 2015 standard of 1,400 pounds of CO_2 per megawatthour, which requires at least partial sequestration. The EMM allows new coal technologies (ultra-supercritical technology) with either 30% or 95% removal rates to be built if economical. The 2024 rule also created different categories for compliance by new natural gas-fired technologies. Plants built after 2023 that are run at a greater than 40% capacity factor must operate with 90% CO_2 capture after 2031, while plants operating at intermediate or low load levels have standards consistent with current efficient designs and use of natural gas or other low-emitting fuel. The AEO2025 represents this restriction in operation on any new natural gas-fired combined-cycle plants that are built without CCS. The EMM does not explicitly represent modified or reconstructed power plants, which are also covered by the rule.

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[5] U.S. Environmental Protection Agency, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, April 25,2024

2. Electricity Load and Demand Submodule

The Electricity Load and Demand (ELD) Submodule translates census region annual electricity consumption projections from the NEMS demand submodules into regional, seasonal and time-of-day load shapes needed to simulate power plant operations and capacity planning decisions in the EMM.

Broadly speaking, the ELD submodule performs two major functions:

- Translates census division annual demand data into EMM region annual data, and vice versa
- Translates the regional, annual electricity consumption projections into seasonal and time-of-day load shapes (load duration curves)

Model objectives

ELD prepares seasonal, time-of-day representations of electricity demand for use in power plant operations and capacity planning decisions. Using historical information on the annual time profile of electricity demand (in other words, system load shapes) at the regional level together with load shape information for individual end-uses (for example, heating, lighting, air conditioning), ELD constructs seasonal and time-of-day load shapes for each year of NEMS operation.

Aggregation level

As with all of the EMM, ELD operates at a 25-region level. The regions are based on North American Electric Reliability Corporation (NERC) regions and subregions as well as Independent System Operator (ISO) and Regional Transmission Organization (RTO) region boundaries, as of 2019 (Figure 3). Two NERC regions are represented in their entirety: Texas Reliability Entity (TRE) and Florida Reliability Coordinating Council (FRCC). EMM defines the other electricity supply regions by splitting the remaining NERC or ISO/RTO regions. In the Northeast Power Coordinating Council (NPCC), the New England states constitute one region, and New York is represented by two subregions. The PJM RTO and the Midcontinent ISO (MISO) each have four subregions. The SERC Reliability Corporation and the Southwest Power Pool each have three subregions, and the Western Electricity Coordinating Council has another six subregions. Because of the topography of the electrical grid in the United States, these regions represent electricity markets better than other options, such as census regions.

Relationship to other modules

The ELD submodule interacts with the ECP, EFD, and EFP submodules within the EMM (intra-module linkages) and with the NEMS demand modules and hydrogen market module (inter-module linkages) (Figure 5). The end-use demand modules, including residential, commercial, industrial, and transportation, provide annual electricity demand by end-use category. The Hydrogen Market Module provides electricity demand related to the operation of electrolyzers to the EMM directly, while other small amounts of electricity used in the fuel modules are passed through the industrial demand module (for example, electricity used in LNG pipelines).

Figure 5. Input/output flows for the Electricity Load and Demand Submodule
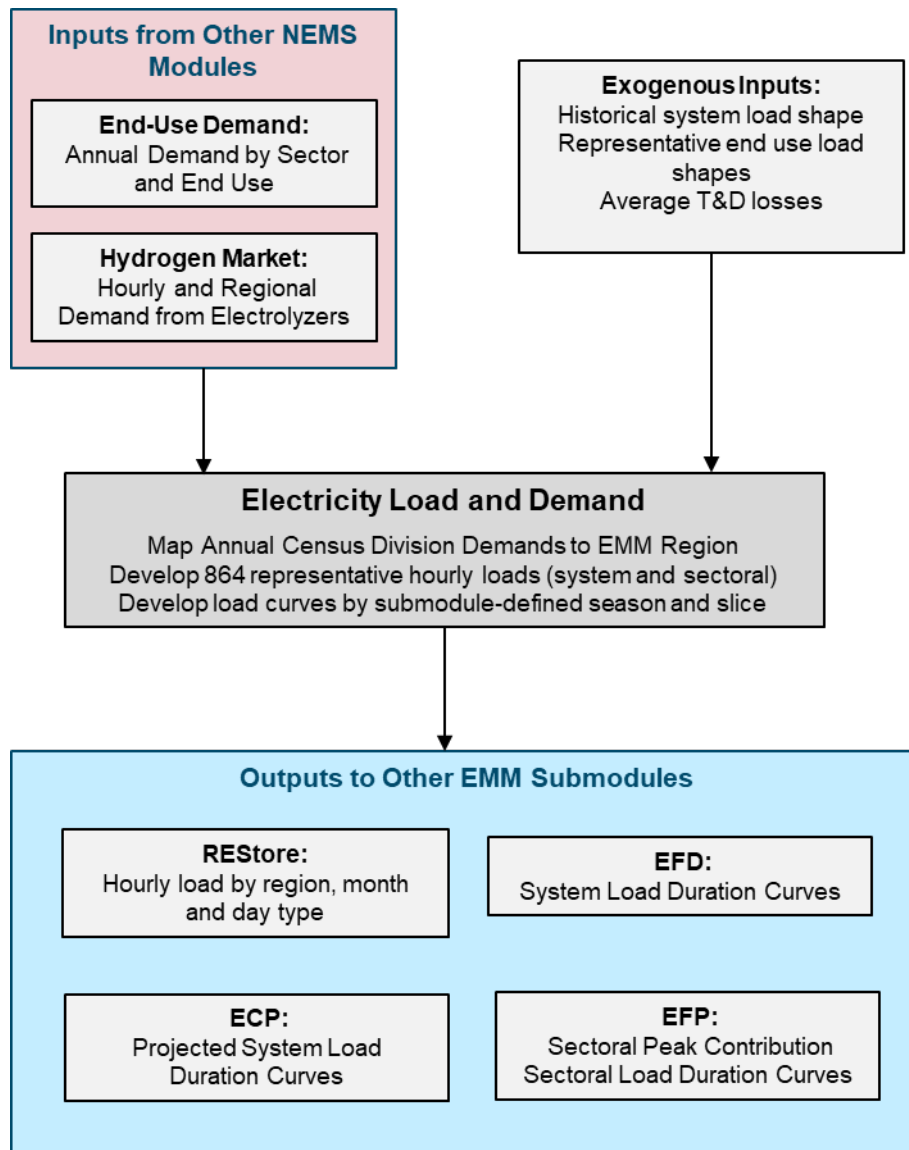
Intra-module data linkages

Within the EMM, key linkages to the ELD are with the Electricity Capacity Planning (ECP) and Electricity Fuel Dispatch (EFD) submodules. The ELD submodule supplies system load duration curves to both ECP and EFD and provides information on sectoral peak demands to EFP.

The following subsections discuss intra-module linkages in greater detail.

Electricity Capacity Planning Submodule

The outputs from the ELD submodule to the ECP are the projected regional system load duration curves for each year in the ECP planning horizon. In each yearly iteration of NEMS, the ELD obtains projections of yearly demand data from the NEMS demand modules. The demand modules produce census division estimates that the ELD converts to EMM regions using the fixed shares method. In this approach, the percentage of each census division's load allocated to an EMM region remains fixed over time for each of the sectors in the demand modules. In other words, the census division to EMM region mapping matrix for each sector does not change over time. Using these projections, the ELD develops system load shapes for each of the 25 EMM regions.

These annual system load data are then converted into seasonal, time-of-day load duration curves (LDCs), which are input to the ECP submodule. The ELD allows for considerable flexibility in the definition of the LDCs. Both the number of segments and the assignment of hours to segments are inputs to the model. Each LDC segment is discrete and is associated with a time-of-day and seasonal definition. Individual LDCs are developed for each of the years represented in the ECP planning horizon.

Renewable Electricity Storage Submodule (REStore)

The REStore submodule uses the hourly system load developed by the ELD. No further aggregation is necessary as REStore operates at the monthly and hourly level that the load shapes are determined. However, REStore currently truncates the peak-day period from the data, as it only examines normal weekday and weekend load patterns to reduce model size.

Electricity Fuel Dispatch Submodule

During each iteration of NEMS, ELD outputs regional LDCs to EFD submodule. Only the current year LDC is used by EFD.

Electricity Finance and Pricing Submodule

ELD passes the peak load demands and load curves from the end-use sectors to the EFP. Competitive markets allocate the capacity payment and costs of spinning reserves to the sectors based on their respective contributions to the overall peak load. The sector load curves are used to weight the marginal energy costs in each time slice to determine average annual competitive prices by sector and end use.

Inter-module data linkages

The NEMS end-use demand modules provide annual demands for electricity by census division. The ELD transforms these demand projections from the demand submodules into EMM regional demand estimates. These estimates are then translated into system load shapes for use by the Electricity Capacity Planning (ECP) and Electricity Fuel Dispatch (EFD) submodules of the EMM module.

Model overview

Philosophical and theoretical approach

The regional, seasonal, and time-of-day patterns of electricity use are critical information needed to properly plan and operate an electricity system. The pattern of usage will affect the types of capacity that can be economically developed and the fuels that will be used to generate electricity. As a result, ELD mostly translates the annual electricity demand values generated by the NEMS demand modules into the regional, seasonal, and time-of-day patterns that EMM needs.

Model structure

Initially, ELD obtains the required inputs from other modules. The Integrating Module provides projections of future electricity demands from the demand modules by end use, building type, and technology type. ELD uses these projections to develop system load shapes for the ECP submodule. The end-use demand modules pass along the corresponding information for the current year, which is required to generate the load curves for the EFD.

Given this information, ELD then performs its two main tasks:

- Mapping nine census division demand estimates into 25 EMM regions
- Developing system load shapes for ECP and EFD

Mapping demand estimates

The ELD submodule provides the interface for demand data between the NEMS demand modules and the EMM module. This component translates the sectoral demand estimates that are produced by nine census divisions within the NEMS demand modules into the 25 EMM regions, using a mapping matrix based on recent historical electricity sales.

Developing system load shapes

ELD follows a methodology to construct electric utility load curves, resulting in seasonal and annual load duration curves for each of the 25 EMM regions. The overall methodology consists of two steps:

- Step 1: Projecting regional chronological hourly loads for each hour of the year
- Step 2: Sorting hourly loads to produce load duration curve (LDC) representations for ECP and EFD, and sectoral load curves for EFP

Projecting regional chronological hourly loads. The ELD submodule develops system load curves at 864 hourly points (to approximate the 8,760 hours in a year) to reflect different appliance usage patterns (for example, space heating demands may be higher at certain hours, while at other times the water heating load may dominate the LDC). In constructing and modifying these curves, ELD combines end-use load shape data from various sources and historical system load shape data collected by EIA. The load shape inputs are developed to provide hourly profiles for each of 3 day types (weekday, weekend and one peak day) for each month, resulting in the 864 data points.

Many utilities use such chronological hourly load shapes (load profiles) to predict customer demand patterns. These utilities develop the hourly system load curves from the bottom up by adding together the hourly loads of individual end uses, such as refrigerators and air conditioners, or classes of end uses. To do this, the utilities must have information about the technologies and usage patterns of their customers. At a national level, however, the building of such load shapes can present significant data

problems. Currently, the end-use load shape data readily available for this effort are not of sufficient quality to allow for the construction of system load shapes from the ground up. In other words, when the load shapes for each end use are summed together, the resulting system load curve does not closely replicate the actual system curve for which data are available. This result may be because the end-use load curves do not conform to the actual usage pattern in the region or there is significant load diversity (for example, not all refrigerators in an area follow the same usage pattern).

The ELD model uses two different approaches to project hourly loads, the Basic Approach and the Delta Approach. In the Basic Approach, hourly loads for each individual end use are calculated and then summed to yield the system hourly loads. In the current version of the code, this approach is used only for the demand sector load curves, which the EFP uses to weight the marginal energy prices by time slice, and to determine the sectoral peak loads that the EFP model uses for certain cost allocation methods.

In the Delta Approach, the starting point is a historical hourly load curve of the system (or other aggregate of end-use loads) observed in a chosen base year. This curve is then modified using the end-use load shapes in case the contribution of the end uses has changed since the base year. The ELD passes this system load curve to the other submodules (ECP, EFD, and REStore) to determine system capacity and operations.

Basic approach. The basic algorithm can be thought of as an end-use building block approach. The system demand is divided into a set of components called end uses. The hourly loads for each end use are projected. Next, the hourly loads of each end use are summed to yield the projection of system load at the customers' meter (in other words, hourly system sales). The final step is to simulate transmission and distribution losses. This process is done separately for each EMM region. The regional hourly loads are calculated as the sum of hourly system sales and transmission and distribution losses.

Computing end-use hourly loads—in projecting the hourly loads for an end use, ELD requires two major inputs:

- Annual sales projection
- Typical load shapes that allocate end-use annual load to each hour in a year

The annual sales projection is determined endogenously in NEMS. NEMS demand models pass the annual sales projected for each of the base end uses to ELD. The typical daily load shapes (24 hour profile) for each end use are an exogenous input to ELD and are input by month and by day type (peak day, weekday, and weekend), resulting in 864 time segments.

End-use load shapes for the residential and commercial end uses were updated for AEO2025 using the National Renewable Energy Lab (NREL) RESTOCK and COMSTOCK databases, and the building types and end-use equipment were aligned with the categories modeled by the NEMS building modules. The transportation demand module represents multiple types of electric vehicles (EVs) and determines where the charging for light-duty vehicles will occur (residential or commercial sites). We used several sources to develop load shapes for the different modes of EV charging, but primarily NREL.

Each record on the input file defines hourly distribution of annual load for one end use. The ELD model refers to the values on each record using the hour-in-the-year index as explained below.

(2-1)
$$DistLo_{eh'} = DHL_{mdh}$$

where

DistLo_{eh'} = fraction of annual load allocated to hour *h'* of a year for end-use *e*; and

DHL_{mdh} = fraction of annual load allocated to hour *h* of day *d* in month m of the projection year.

Combining end-use load shapes—the next step is to combine the end-use hourly load shapes into one system load shape for the projection year. We accomplish the combination of end-use hourly loads by an hour-by-hour summation during the projection year. We conduct this procedure for each EMM region as follows:

$$(2\text{-}2) \qquad SYLOAD_{h'} = \sum_{e=1}^{NUSES} DistLo_{eh'} \times load_{1e}$$

where

SYLOAD(h) = system load in hour *h'* of a year;

NUSES = number of end-uses *e*; and

load_{1e} = annual load projection for end-use *e* (1 stands for base type approach).

Simulating transmission and distribution losses—the system load shape calculated above is the sum of hourly sales for each end use (for example, lighting, heating, refrigeration). So, it is the hourly sales for the system. EFD and ECP require hourly generation requirements, not hourly sales. The final step is to increase the hourly system load requirements by the fraction of generation lost on transmission and distribution, which was estimated through analysis of historical data.

In ELD, this final step is accomplished by multiplying the hourly load values in the EMM region system load curves by the exogenously defined transmission and distribution loss factor. A transmission and distribution loss factor represents an average of an EMM region's percentage of energy lost during transmission and distribution.

Delta approach. This section describes the formulation of system load shape for use in dispatch and capacity expansion within the other EMM submodules. This approach allows ELD to take advantage of the initial system database yet still produce reasonable projections. This approach is termed the Delta approach, and as with the Basic approach, is done separately for each EMM region.

The Delta Approach starts in the initial years with a base utility system load shape. This base shape is used for any historical model years and through the period that includes benchmarking to the Short Term Energy Outlook. For AEO2025 the system load shapes were updated by EMM region using data from 2018 to 2022 reported on the Form EIA-930 and normalized for weather by developing a regression model using temperature, wind speed, relative humidity, and parameters related to the time of day.

Next, the delta approach uses the same end-use load shapes described in the Basic Approach but instead applies only the incremental changes in the end-use load category to the system load. The resulting hourly load projection of this formulation is a shape that in the early projection years is very

similar to current observed shapes. Over time, the shape will change in response to changes in end-use mix.

The Delta Approach is represented by the following formula, by EMM region:

(2-3) $SYLOAD_{h'} = DistLo_{Sh'} \times SystemLoad_y + \sum_{e=1}^{NUSES} DistLo_{eh'} \times load_{2e}$

where

S	=	Total electric system;
$SYLOAD_{h'}$	=	system load in hour *h'* of the year; and
$load_{2e}$	=	difference between the end use's annual energy consumption in the current year and the base year (2 indicates the Delta approach—positive or negative value).
$SystemLoad_y$	=	total electricity system load in year y;
$DistLo_{eh'}$	=	hourly load shapes for end-use *e* in hour *h'*;
$DistLo_{Sh'}$	=	historical hourly system load shape in hour *h'*; and
NUSES	=	number of end uses.

while

(2-4) $load_{2e} = load_{1e} - \text{slr} \times BaseYrLd_{er}$

where

$BaseYrLd_{er}$	=	base year load for end-use *e* in EMM region *r*;
slr	=	SystemLoad$_y$ / BaseSystemLoad = growth in total system load for year y
$load_{1e}$	=	current year load for end-use *e* (1 indicates total load, as used in Basic Approach); and
$load_{2e}$	=	difference between end-use e's annual energy consumption in the current year and expected growth from the base year (2 indicates Delta approach—positive or negative value).

Accounting for Electrolyzer Demand for Hydrogen Production

The Hydrogen Market Module (HMM) operates at the same regional level as EMM and operates electrolyzer plants at an hourly level for each month of the year. Therefore, electricity demand from HMM is processed differently than the other end-use sectors. An input end-use load shape is not required, instead the hourly demand is passed and mapped to each hour directly and added to the final projected system load shape for each EMM region. This demand is mapped to an additional end use in the industrial sector for accounting purposes.

Developing load duration curves for the other EMM submodules

Load Duration Curves (LDCs) are used by both the ECP and the EFD submodules. An LDC consists of a discrete number of blocks. The height of each block gives the projected load, and the width represents the number of hours with that specified load. Summing the widths of all blocks in the LDC gives the total number of hours in the year. However, because of the differing needs of the ECP and EFD submodules,

LDCs created for each of these submodules differ. The following sections describe the specific steps used to develop LDCs. As noted previously, the RESTORE submodule uses the chronological hourly load data from the ELD directly (although dropping one of the three day types to reduce from 864 to 576 representative hours) and does not require any aggregating or sorting into an LDC.

Load duration curves for ECP

Demand for electricity is input to the ECP submodule by means of approximated LDCs, specified for each of the 25 EMM regions. Both the number of blocks and the assignment of hours to blocks are specified as input data to the program. The larger the number of blocks used, the more accurate the representation of the continuous load curve. However, as the number of blocks is increased, the size and execution time of the model increases significantly. Typically, analyst judgment is used to select the minimum number of blocks needed to reasonably represent the load faced by electricity suppliers.

The assignment of hours to blocks is completed in two steps; in each, a different sorting criteria is followed. In the first step, the 8,760 hours that make up a year are assigned to a number of segments that can be defined by month, day type, and time of day, and then hours within each segment are arranged in descending order of load. In the second step, each segment is divided into a number of blocks, each of which has a specified percentage of the hours assigned to that segment. Two types of blocks are allowed: regular and peak. The height of a regular block equals the average load of hours assigned to that block, while the height of a peak block equals the highest hourly load for hours assigned to that block.

The width of each block equals the number of hours in the block. The area of a regular block represents the energy demand during the hours assigned to it. The area of a peak block slightly overestimates the actual load during the hours assigned to the block. However, for narrow peak blocks, the error in approximation is not very significant. The advantage of this approach is a precise representation of the peak load. To ensure that the total energy represented by the approximated LDC curve equals the regional demand, the excess energy in the peak blocks is evenly subtracted from the regular blocks. In the final step, all of the blocks from the segments are sorted in descending order.

Load duration curves for EFD

EFD uses LDCs that are created for each season and for each of the 25 EMM regions. The steps involved in their creation are nearly the same as in the case of the ECP LDCs. The only difference is that the process is performed for each season separately.

Sectoral Load duration curves for EFP

EFP uses sectoral LDCs that are based on the same seasons and time slices as the EFD. The steps involved in their creation are the same as in the case of the EFD LDCs, however they are done by end use sector using the Basic approach, rather than the total system load shape (which cannot be allocated to sectors). This is done so that the competitive end-use prices can be determined based on a weighted marginal average price using the end-use load in the corresponding time segments.

Appendix 2.A. Data Sources

This appendix provides a list of the data sources in the Electricity Load and Demand (ELD) Submodule. Each data source is accompanied by a brief description.

Survey forms

Form EIA-930, Hourly and Daily Balancing Authority Operations Report
The Form EIA-930 collects hourly electric system operating data from electricity Balancing Authorities in the contiguous United States. Data collected include system demand, net generation, and interchange and is submitted on an hourly (for demand) and daily (for all data types) basis.

National Oceanic and Atmospheric Administration

The Global Historical Climatology network-hourly is a collection of weather station observations from across the U.S. and world, with datasets back to 1900. EIA used 30 years of weather data to normalize the system load curves.

National Renewable Energy Laboratory

ResStock
Residential Building Stock model, provides end-use load profiles for the U.S. building stock.

ComStock
Commercial Building Stock model, provides end-use load profiles for the U.S. building stock.

EVI-Pro Lite
NREL's Electric Vehicle Infrastructure – Project Tool estimates how much electric vehicle charging infrastructure is needed in a designated area to meet a given demand. EIA used the EVI-Pro Lite Load Profile tool to develop load shapes for the residential and commercial sector light duty vehicle charging profiles. An average of the public workplace charging curve and the residential curve (primarily overnight) was used for transit buses to reflect a mix of charging during the route and returning to a depot for overnight charging.

Electric Power Research Institute

Electric School Bus Fleet Load Shapes and their Relationship to Distribution Feeder Hosting Capacity, Technical Brief, July 2023. This article was used as a basis for developing the school bus load shape.

3. Electricity Capacity Planning Submodule

This chapter documents the objectives and analytical approach of the Electricity Capacity Planning (ECP) Submodule, which represents investment decisions such as capacity additions and compliance strategies for environmental regulations. It includes the key assumptions, computational methodology, and data requirements of the model.

Model summary

ECP considers planning decisions involving changes in capital stock that occur over several years and require a substantial capital investment. It projects how the electric power industry will change its generating capability in response to future fuel prices and demands, changes in environmental regulations, technology costs and performance, and financing costs. ECP contains a dispatching component so that planning decisions consider the trade-off between investment and operating costs.

ECP examines strategies for complying with environmental legislation, such as the Clean Air Act Amendments of 1990 (CAAA). Consistent with rules currently in place promulgated under authority of CAAA requiring the addition of post-combustion controls (such as EPA's Mercury and Air Toxics Standards—or MATS—rule), ECP selects the least-cost options for achieving the SO_2 and NO_x emissions reductions, comparing installing pollution control equipment on existing power plants and building new power plants with low emission rates. These methods for reducing emissions are compared with dispatching options such as fuel switching and allowance trading. Environmental regulations also affect capacity expansion decisions. For instance, new plants are not allocated emissions allowances according to the CAAA. So, the decision to build a particular capacity type must consider the cost (if any) of obtaining sufficient allowances, which could involve purchasing allowances or over-complying at an existing unit. ECP also represents restrictions on NO_x, Hg, and CO_2 emissions. For the AEO2025, ECP represents:

- EPA's Cross State Air Pollution Rule (CSAPR) to reduce SO_2 and NO_x emissions
- California Global Warming Solutions Act of 2006 (AB398) limits on CO_2 emissions
- Regional Greenhouse Gas Initiative (RGGI) limiting carbon emissions from electricity generating facilities in 11 northeastern states
- EPA's MATS rule to regulate hazardous air pollutants
- EPA's updates to Section 111 of the Clean Air Act finalized in 2024

Potential options for new generating capacity include central-station plants using fossil fuel, nuclear, renewable power (including intermittent technologies such as solar and wind), and distributed generation resources. As new technologies become available, they compete with conventional plant types as sources of supply in ECP. ECP contains a technology penetration component, which represents changes in cost and performance characteristics as a result of learning effects, risk, and uncertainty.[6] ECP also contains a market-sharing algorithm and evaluates plant retirement decisions.

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[6] For a more detailed description, see U.S. Energy Information Administration, *NEMS Component Design Report Modeling Technology Penetration* (Washington, DC, March 1993).

ECP includes the option (although not currently modeled in AEO2025) to build a new demand response technology to simulate load shifting through time-of-use pricing programs using smart meters. This demand response technology is modeled as a new technology build with operating characteristics similar to energy storage. The technology is able to decrease the load in peak slices, but it requires generation to replace that demand in other time slices. An input factor identifies the amount of replacement generation needed, where a factor of less than 1.0 can be used to represent peak shaving rather than purely shifting the load to other time periods. The AEO2025 cases no longer project builds of this technology type because the REStore Submodule has added a more detailed modeling of battery storage (Appendix 3.D). The battery storage technology also represents a method of reducing and shifting peak demand use.

Model purpose and objectives

The purpose of ECP is to determine how the electric power industry will change its mix of generating capacity over the projection horizon. It considers investment decisions for new capacity and evaluates retirement decisions for fossil fuel, nuclear, and wind plants. ECP represents changes in the competitive structure (in other words, deregulation). As a result of competition, no distinction is made between utilities and nonutilities as owners of new generating capacity. ECP also captures changes to plants (for example, pollution control devices) in response to environmental regulations, such as the CAAA. It can represent limits on SO_2, NO_x, Hg, and CO_2 emissions.

Technology choices in ECP include all the fuel types used by suppliers—coal, natural gas, petroleum, uranium, and renewable. AEO2025 also introduces a hydrogen-fueled turbine, with hydrogen fuel prices provided by the Hydrogen Market Module. ECP represents capacity additions of conventional and advanced technologies. Conventional technologies are identified by fuel type (coal, natural gas, petroleum, uranium, and renewable) and prime mover (for example, steam, combined cycle, combustion turbine, hydraulic turbine, and wind turbine). These categories correspond to data collected on Form EIA-860, *Annual Electric Generator Report*. Steam turbines use fossil fuel, nuclear, and some renewable energy sources (for example, geothermal). Combined-cycle and combustion turbine units primarily use natural gas and petroleum. Hydraulic turbines include conventional and the operation (but not new build) of pumped storage. Advanced technologies include ultra-supercritical coal plants with and without carbon capture and sequestration (CCS), natural gas-fired CCS plants, hydrogen turbines, fuel cells, and advanced nuclear reactors. Renewable technologies include geothermal and biomass (wood). Intermittent renewable capacity includes wind and solar generators. Energy storage includes the building and operation of new battery storage, as well as the operation of existing pumped hydro storage facilities. Power sector distributed generation options are represented as generic technologies serving peak and base loads and are assumed to consume natural gas. Rooftop solar PV capacity is determined by the residential and commercial modules, but the capacity is taken into account in EMM based on resource availability throughout the year. Distributed wind, on-site self-generation from fossil-fueled capacity, and customer-owned combined heat and power capacity and generation are determined by the residential, commercial, and industrial modules and passed through to the EMM as reduced electricity demand.

ECP represents planning decisions for 25 electricity supply regions (Section 1, Figure 3). The regions follow North American Electric Reliability Corporation (NERC) assessment region boundaries and

Independent System Operator (ISO) and regional transmission organization (RTO) region boundaries (as of early 2019). Additional subregions are based on regional pricing zones.

The general level of aggregation for NEMS is census divisions, which are collections of states.[7] However, many utilities operations are incongruent with state boundaries, and the EMM regions provide a better representation of electricity operations, reliability, and capacity planning decision making. This geographic representation also facilitates collection of data and comparisons with industry projections, both of which are generally conducted at the utility level, NERC region level, or the ISO/RTO market level.

Because of the close relationship between the electricity and coal markets, ECP also contains a representation of the coal supply and demand regions to more accurately reflect production and transportation costs. Existing coal-fired plants are identified by both their electricity and coal demand regions to specify the appropriate electricity loads they meet and the delivered coal prices for generation. Similarly, new coal-fired generator units are built in the coal demand regions but are linked to the electricity regions that they serve. Decisions to build new coal-fired generator units, as with other technologies, consider the average transmission costs to connect to the grid in addition to the costs to build the capacity.

ECP, as a component of EMM and NEMS, provides projections for the *Annual Energy Outlook* and other analyses. For the electric power industry, the model projects planning decisions for each year in the midterm projection horizon, currently defined as through 2050. ECP also examines the impact of environmental regulations, such as those authorized under the CAAA, covering limits on emissions of SO_2, NO_x, CO_2, and Hg. In addition, ECP examines the economic tradeoffs between the potential suppliers and the available generating technologies in response to different fuel price trajectories, environmental requirements, and macroeconomic conditions. ECP can examine issues related to international and interregional trade, but it does not represent intra-regional trade for the 25 electricity regions.

ECP represents the option to add interregional transmission capacity between adjacent regions. In some instances, it may be more economical to build generating capacity in a neighboring region even with additional costs to expand the transmission grid. This additional transmission capacity may also be used for economy trades.

Relationship to other models
In addition to exogenous sources, ECP requires input data from other modules of NEMS and other submodules of the EMM (Figure 5). Exogenous inputs include existing operable capacity, planned capacity additions, and announced capacity retirements. Data inputs also include the age of existing units, which will be used in the representation of refurbishment, and retirement decisions. For each capacity type that is a candidate for capacity expansion, external assumptions include overnight

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[7] The demand, conversion, and supply modules of NEMS use the regional aggregation that is most appropriate for the corresponding energy market. However, the required data flows provided to the Integrating Module for convergence testing and reporting (for example, energy prices and quantities) are specified for the nine census divisions. For additional information, see U.S. Energy Information Administration, *Integrating Module - NEMS Documentation,* DOE/EIA-M057 (2025) (Washington, DC, August 2025).

construction cost (in other words, capital costs without interest accrued during construction), construction expenditure profile, economic life, maximum fuel shares, heat rate, and outage rates. Planned additions and retirements as reported to EIA surveys are assumed to occur as scheduled. ECP also exogenously specifies transmission and trade data inputs. Transmission and trade data include the expected level of international and interregional electricity trade based on known contracts and the costs of constructing new generating units in selected regions to serve loads in a neighboring region.

The other modules within NEMS, through the Integrating Module, provide expected fuel prices and expected electricity demands. Because variations in natural gas consumption can result in considerable differences in the corresponding price, the Natural Gas Market Module (NGMM) provides supply curves for the annual production and distribution costs. The end-use demand modules furnish electricity from cogenerators, which decrease the generation requirements from power plants. RFM provides cost and performance data for plant types fueled by renewable energy sources. For intermittent technologies, RFM will also provide the capacity credit, which represents the corresponding contribution to reliability requirements.

The EFP submodule supplies the capital structure (debt/equity shares) and the cost of capital. The ELD submodule furnishes the load curves for each year in the planning horizon.

The EFP submodule requires the capital expenditures for building new capacity and installing pollution control devices on existing units to calculate electricity prices. The EFD submodule uses capacity additions from ECP to determine available capacity for meeting demand in a given year.

The outputs of ECP, which are determined by the selection of the least-cost options for meeting expected growth in demand, interact with other modules of NEMS and submodules of EMM. ECP provides its decision variables to other submodules of EMM (Figure 6). RFM also receives capacity additions of renewable technologies. In particular, technologies with resource constraints or limited sites require this process.

The interaction between ECP and the Coal Market Module (CMM) is particularly important because the electricity and coal markets are closely related. Electricity production currently accounts for most of the coal consumption in the United States. Coal is a major input fuel for electricity production and currently accounts for a substantial fraction of the regulated power plant emissions in the US. Coal supplies vary considerably according to cost (production and transportation) and characteristics (British thermal units [Btu] content, sulfur content, and mercury content). Therefore, ECP includes a detailed representation of the coal supply curves contained in CMM.[8]

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[8] For more information on the description of coal production, transportation, and environmental limits in CMM, see U.S. Energy Information Administration, *Coal Market Module of the National Energy Modeling System*, *Model Documentation 2025*, DOE/EIA-M060(2025) (Washington, DC).

Figure 6. Input/output flows for the Electricity Capacity Planning Submodule

Inputs from Other NEMS Modules

Integrating:
Fuel Price Expectations
Electricity Demand Expectations

End-Use Demand:
Annual Demand
Capacity and Generation from Cogenerators

Renewable Fuels:
Cost and Performance Data

Coal Market:
Coal Supply Curves
Flow Constraints

Natural Gas Market:
Natural Gas Supply Curves
Natural Gas Price Markups

Hydrogen Market:
Hydrogen Supply Curves

Carbon CATS:
Market prices for captured carbon

Exogenous Inputs:
Capital Costs
Operating Costs
Construction Profile
Reserve Margins
Outage Rates
Existing Capacity
Planned Additions
Heat Rates
Emission Rates
Firm Trade
Transmission Capacity

Inputs from other EMM Submodules

ELD:
Load Curves

EFP:
Capital Structure
Cost of Capital/Discount Rate

REStore:
Intermittent and Storage Hourly Capacity Factor
Storage Arbitrage Value

Electricity Capacity Planning

Determine New Capacity Additions
Compute Construction Costs
Compute Avoided Costs
Decide Emissions Banking
Determine Pollution Control Retrofits
Determine Capacity Retirements
Compute Allowance Prices and RPS Prices

Outputs to Other NEMS Modules

Renewable Fuels:
Renewable Capacity Additions

Coal Market:
Emissions banking

Hydrogen Market:
Hourly renewable generation, curtailment and prices (via REStore)
Renewable capacity by vintage

Outputs to Other EMM Submodules

EFD:
Available Capacity by Plant Type
Emission banking
Allowance and RPS prices
Retrofit decisions
Biomass cofiring shares

EFP:
New Plant Cost Recovery
Retrofit Decision Costs
New Transmission Costs

Model overview

Theoretical approach

ECP uses a linear programming (LP) formulation to determine planning decisions for the electric power industry. This approach uses a three-period planning horizon to examine costs over a 30-year period. The first period is the current year when decisions are made to initiate investment decisions; the second period is the following year; and the final period of the planning horizon considers the accumulated costs for the final 28 years of the cost recovery period. The model uses multiyear optimization as it solves all the years simultaneously. NEMS executes ECP once each model year, so the 30-year planning horizon is based on the current model year, incorporating previous capacity expansion and retirement decisions into the capacity baseline.

ECP contains a representation of planning and dispatching to examine the trade-off between capital and operating costs, simulating least-cost planning and competitive markets by selecting strategies for meeting expected demands and complying with environmental restrictions that minimize the total discounted present value of investment and operating costs during the planning horizon. The costs reflect any tax credits in place under current laws and regulations, such as investment or production tax credits for new nuclear and renewable technologies, and tax credits for carbon capture and sequestration. ECP explicitly incorporates emissions restrictions imposed by CAAA, as well as updates to Section 111 of the CAA regulating CO_2 emissions. AEO2025 incorporates CSAPR, MATS, RGGI, and AB398.

To describe the demands for electric power, ECP uses the projected load duration curves (LDC) provided by ELD. A typical LDC arranges hourly loads in descending order, but it does not identify power requirements chronologically. We categorize the load requirements into specific seasonal/time-of-day segments, which are then reordered to provide a monotonically decreasing curve. Maintaining the chronological identity of the demands for electric power allows ECP to better represent time-dependent variations in both the demand for and supply of electricity.

In ECP, the available supply options are characterized by the degree of control they provide the operator of the system. Assuming adequate fuel supplies, fossil fuel and nuclear units are considered dispatchable because they can usually be operated at any time as long as they are not out of service because of planned or forced outages. Some renewable generating capacity, such as geothermal and biomass, is similar to fossil fuel-fired and nuclear plants in that it can be dispatched at the discretion of the operator, subject to limits on the renewable energy source and maintenance schedules. The utilization of hydroelectric plants typically depends on the available water supply, which varies considerably by region and season. Intermittent technologies, such as solar and wind, are less flexible because they can be operated only when the resource occurs (unless accompanied by some storage capability). A battery storage technology can be used to provide power during periods of high-cost generation, but it must then recharge in other time slices, effectively increasing demand during those times.

In ECP, a market-sharing algorithm adjusts the solution from the LP model to allow penetration of competitive but not least-cost alternatives.[9] The LP model evaluates planning decisions on the basis of average (expected) costs and chooses the options that result in the minimum combination of investment and operating costs. However, cost and performance parameters for technologies are more accurately represented by distributions rather than single-point estimates, such as the means. If the distributions of two or more technologies overlap, then the lowest-cost option is not likely to capture the entire market because some quantity of the selected activity will be more expensive than some quantity of the option (or options) that is not selected on the basis of average costs. The market-sharing algorithm determines the competitiveness of technologies not selected by the LP and reallocates some of the capacity additions to those that fall within a prespecified level.

Fundamental assumptions[10]

ECP assumes that capacity additions that are already under construction will be completed as reported.[11] The ECP submodule also assumes scheduled retirements of existing units will occur as reported on the EIA-860 Electric Power Industry Report survey. However, a large number of fossil fuel-fired steam generating units are approaching or have surpassed the end of their originally expected operating lives, but utilities have not indicated any plans to retire them. ECP evaluates whether it is more effective to continue operating those units or to replace them with new capacity. Thus, ECP only determines capacity additions and retirements over and above those currently planned that are required to meet new demand, replace retiring capacity, and comply with environmental regulations. Any new projects initiated by the model are assumed to be completed on schedule. End-use demand modules determine contributions from cogenerators.

ECP determines capacity additions that must be sufficient to satisfy minimum reliability requirements in each of the electricity supply regions. ECP assumes a fixed reserve margin requirement to determine the capacity required above peak demand, and credits the technologies based on their resource availability. EIA is unable to replicate the approaches to determining planning reserve margin and capacity accreditation used in the various planning entities (balancing authorities, RTOs, and ISOs) because of the many varied approaches used and because of the highly detailed input data required. Therefore, we use the apparent reserve margin based on observed recent data for peak demand and installed capacity as accredited per approaches described in the RFM documentation. Firm international and interregional capacity trade contribute to the reliability requirements of the importing region. Similarly, capacity built and operated in one region but serving load in another region is counted toward the reserve margin in the destination region.

ECP determines planning strategies to implement that will meet electricity demands and environmental requirements in future years. Therefore, having information about future demands and fuel prices is

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[9] For more information, see U.S. Energy Information Administration, *Component Design Report Electricity Capacity Planning* (Washington, DC, August 1992).

[10] For more detailed information see U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2025*, DOE/EIA-0554(2025) (Washington, DC, April 2025).

[11] Planned capacity additions are reported on the Form EIA-860, *Annual Electric Generator Report*.

necessary. Perfect foresight is used for future demands and prices.[12] Interest rates and inflation rates tend to remain fairly stable over time, so ECP assumes these will remain constant at current levels (in other words, the latest available rates, which correspond to the results from the previous projection year). Similarly, ECP assumes the capital structure for financing new investments to be the current share of debt and equity. The discount rate is the after-tax, weighted average cost of capital.

The expected demands represent annual electricity sales for the nine census divisions. For each year in the planning horizon, ECP maps the corresponding demands into the 25 electricity supply regions using constant shares derived from historical data. Demand for electric power fluctuates considerably over time (Figure 7). The ECP submodule captures chronological variations in the load using a historical distribution of hourly load data from NERC. The hourly loads are then classified into three different seasonal periods (summer, winter, and spring/fall). Demands for electric power are typically similar in the spring and fall so the corresponding loads are combined to reduce the size of the model. For each seasonal period, the loads are segregated into three categories: peak (highest 1% of demands), intermediate (next 49% of demands), and base (lowest 50% of demands). Therefore, there are a total of nine seasonal/load segments (Table 2).

Figure 7. Typical annual load curve

megawatt

hour
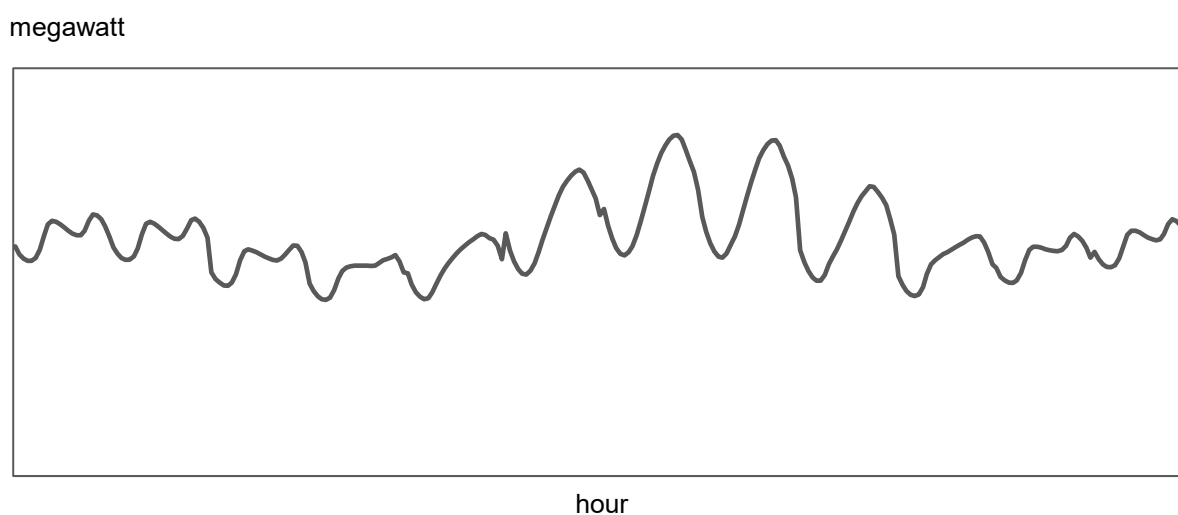
Table 2. Definition of seasonal/time-of-day load segments

Seasonal group	Months	Load type
Summer	June–September	Peak
Summer	June–September	Intermediate
Summer	June–September	Base
Winter	December–March	Peak

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[12] The fuel price and demand expectations are based on the results from previous solutions so that the inputs are consistent with the outputs of current simulation.

Winter	December–March	Intermediate
Winter	December–March	Base
Fall/spring	April–May, October–November	Peak
Fall/spring	April–May, October–November	Intermediate
Fall/spring	April–May, October–November	Base

The hourly loads in each of the nine categories, which produce a continuous curve, are approximated by vertical, rectangular blocks (slices). The heights of the rectangles are the average loads (capacity requirements) for the seasonal/load categories, and the widths of the three peak segments are defined by the corresponding number of hours. Therefore, the area of each rectangle represents the electricity generation (energy requirement). Within each season, the three load segments are then sorted in descending order of height.

Planning decisions are projected for each of the 25 electricity supply regions represented in EMM. Each of these regions is treated as a single firm because intra-regional electricity trade is not explicitly represented. Within each region, the available generating capacity is allocated to meet the demand for electricity on the basis of cost minimization, subject to relevant regulatory and environmental constraints. Bulk power purchases among the electricity supply regions are represented with the limits on power flows based on region-to-region transmission constraints.[13]

This initial transmission capacity has been assumed to be available throughout the NEMS projection time horizon. ECP calculates transmission line capacity available for new transactions by subtracting known contracted capacity from the original transmission line capacity. Based on established relationships among selected electricity supply regions, interregional transmission capacity can be added, and new plants can be built in one region to serve another region. ECP incorporates international trade with Canada as well as firm power transactions with Mexico.

Potential options for reducing SO_2 emissions include installing pollution control equipment at existing units, building new units with lower emission rates, switching to a lower-sulfur fuel, and revising the dispatch order to use capacity types with lower emission rates more intensively. ECP represents allowance trading in the CAAA by imposing a national-level limit on emissions that corresponds to the sum of the allowances allocated to individual generators. In effect, this process simulates an allowance market in which producers with comparatively low costs of reducing emissions can overly comply and sell their excess allowances to suppliers with uneconomical compliance costs.

The CSAPR rule regulates annual SO_2 emissions for 21 states, annual NO_x emissions for 17 states, and seasonal NO_x emissions for 22 states. With few exceptions, the EMM regions do not correspond to states. Instead, the emissions are represented for the coal demand regions, which are combinations of states. For any coal region with multiple states subject to the CSAPR, the individual targets are summed.

The MATS require maximum achievable control technology (MACT) to control hazardous air pollutants (HAPs), including Hg, acid gases, metals, and organics. EMM represents the Hg standards by requiring a

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[13] Interregional transmission constraints are derived from transmission capacity inputs to the National Renewable Energy Laboratory's ReEDS (Regional Energy Deployment System) model.

90% removal of the uncontrolled emissions by installing control equipment or by using activated carbon injection, or both. EMM does not account for the other HAPs, but these requirements are implemented by specifying that covered coal-fired generator units must have either flue gas desulfurization (FGD) or dry sorbent injection (DSI) systems. In addition, EMM assumes this generating capacity to require a full fabric filter to capture emissions of metals and improve the performance of the DSI equipment. In addition to federal emissions requirements, emissions from generating units are also assumed to satisfy state regulations. Compliance options are limited to those that follow all standards. As a result, an existing coal-fired generator unit without a scrubber may be limited to the types of coal that can be consumed (for example, low-sulfur instead of medium- or high-sulfur) by one or more of the standards.

AEO2025 continues to include California's AB398. This bill covers several greenhouse gases (GHGs), but it is implemented only for CO_2 in the power sector (including cogeneration facilities, plants owned by California suppliers but located in other states, and electricity imports) as well as emissions from industry, refineries, fuel providers, and other covered sectors.

AEO2025 reflects updates to Section 111 of the Clean Air Act (CAA) regulating CO_2 emissions from existing coal, oil, and natural gas-fired steam generating units and new natural gas-fired combustion turbines. The ruling requires existing steam turbines at coal-fired power plants to either convert to a natural gas-fired steam unit or cofire with at least 40% natural gas by 2030 if the units are intended to retire by January 1, 2039, or they must be retrofitted with a carbon capture and sequestration (CCS) system with a 90% capture rate by 2032 if they are intended to operate beyond January 1, 2039; otherwise they must retire before 2032. ECP represents these requirements for existing coal plants, allowing the model to make economic decisions regarding conversion fully to natural gas-fired operation, conversion to cofire with natural gas, or retrofit with a CCS system by the appropriate deadlines. EPA also revised carbon pollution standards for new, modified, and reconstructed power plants under CAA Section 111(b). Plants built after 2023 that intend to run at greater than 40% capacity factor must operate with 90% CO_2 capture by 2032, while plants operating at intermediate or low load levels have standards consistent with current efficient designs and use of natural gas or other low-emitting fuel. The ECP represents this restriction in operation on any new natural gas-fired combined-cycle plants that are built without CCS.

In ECP, available supply options include fossil fuel-fired, nuclear, and renewable plants (Table 3). Where appropriate, alternative designs of a technology may be represented to reflect the current and future options. Fossil fuel-fired capacity consumes coal, oil, and natural gas. Renewable technologies include hydroelectric, biomass, geothermal, municipal solid waste, wind, and solar. ECP also includes battery storage technology.

Table 3. Capacity types represented in the Electricity Capacity Planning Submodule

Category
Existing coal steam
Ultra-supercritical coal
Ultra-supercritical coal with 30% and 95% carbon sequestration
Natural gas/oil steam turbine

Existing combustion turbine

New combustion turbine—aeroderivative

New combustion turbine—industrial frame

Hydrogen turbine

Existing natural gas/oil combined cycle

New natural gas/oil combined cycle—single shaft (1x1x1) configuration

New natural gas/oil combined cycle—multi shaft (2x2x1) configuration

New combined cycle with 95% carbon sequestration

Fuel cell—solid oxide

Conventional nuclear

Advanced nuclear—advanced light water reactor

Advanced nuclear – small modular reactor

Biomass (wood)

Biomass with 95% carbon sequestration

Municipal solid waste—landfill gas-fired internal combustion engine

Geothermal

Conventional hydropower

Existing pumped storage

Diurnal/battery storage—four-hour lithium ion battery

Wind - onshore

Wind - offshore

Solar thermal

Solar photovoltaic with single-axis tracking

Solar photovoltaic with battery storage

Generic distributed generation—base load

Generic distributed generation—peak load

Existing coal-fired capacity is represented by 32 categories that are defined by the types (if any) of particulate, SO_2, NO_x, and Hg control devices. These plant types are typically classified as unscrubbed or scrubbed, depending on whether they have Flue Gas Desulfurization (FGD) equipment. A given capacity type can include several different configurations because pollutants such as NO_x can be controlled using multiple devices such as low-NO_x burners, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR). Each configuration is characterized by a removal rate for each of these emissions. Retrofitting pollution control devices to comply with specified emissions limits can convert a given coal-fired capacity type to another configuration or category.

As a result of the revision to the new source performance standards specified under Section 111(b) of the CAA, AEO2025 assumes that new coal-fired plants must have at least 30% carbon capture; a 95% carbon sequestration technology is also available.

ECP captures uncertainty about investment costs for new technologies using technological optimism and learning factors. These factors are calculated for each of the major design components of a plant type design (Table 4). For modeling purposes, components are identified only if the component is shared among multiple plant types so that the ECP can reflect the learning that occurs across technologies. In the case of solar photovoltaic (PV) technology, ECP assumes the module component to account for 30% of the cost, while the balance of system components accounts for the remaining 70%. Because the amount of end-use PV capacity (existing and projected) is significant relative to total solar PV capacity, and because the technology of the module component is common across the end-use and electric power sectors, the calculation of the learning factor for the PV module component also accounts for capacity built in the residential and commercial sectors.

Table 4. Design components represented in the Electricity Capacity Planning Submodule

Category
Pulverized coal
Hydrogen
Combustion turbine—natural gas
Heat recovery steam generator (HRSG)
Gasifier
Carbon capture/sequestration
Balance of plant—turbine
Balance of plant—combined cycle (CC)
Fuel cell
Advanced nuclear
Biomass
Distributed generation—base
Distributed generation—peak
Geothermal
Hydropower
Battery storage
Wind
Wind offshore
Solar thermal
Solar PV—module
Balance of plant—solar PV

Once the ECP calculates the learning rate by component, a weighted average learning factor is calculated for each technology, using weights based on the share of the initial cost estimate that is attributable to each component. Table 5 shows components that contribute to multiple fossil plant types. In the case of the solar PV technology, we assume the module component accounts for 38% of the cost, and we assume the balance of system components account for the remaining 62%. Because the amount of end-use PV capacity (existing and projected) is significant relative to total solar PV capacity and the technology of the module component is common across the end-use and electric power sectors, calculating the learning factor for the PV module component also takes into account capacity built in the residential and commercial sectors. The PV with battery storage cost is split between the battery component (26%), the PV module (29%), and the PV balance of system (45%). For

the offshore wind technology, we assume that offshore-specific components make up 50% of the cost, and the remaining 50% overlaps with the onshore wind technology.

Table 5. Component cost weights for new technologies

Technology	Pulverized coal	Hydrogen	Combustion turbine	HRSG	Carbon capture and sequestration	Balance of plant— turbine	Balance of plant— combined cycle
USC with 30% CCS	90%	0%	0%	0%	10%	0%	0%
USC with 95% CCS	80%	0%	0%	0%	20%	0%	0%
Combined-cycle—single-shaft	0%	0%	25%	10%	0%	0%	65%
Combined-cycle—multi-shaft	0%	0%	25%	10%	0%	0%	65%
Combined-cycle with 95% CCS	0%	0%	15%	5%	40%	0%	40%
Combustion turbine— aeroderivative	0%	0%	50%	0%	0%	50%	0%
Combustion turbine— industrial frame	0%	0%	50%	0%	0%	50%	0%
Hydrogen turbine	0%	5%	48%	0%	0%	48%	0%

Note: HRSG = heat recovery steam generator, CCS = carbon capture and sequestration

The cost adjustment factors are based on the cumulative capacity of a given component. Table 6 shows the capacity credit toward component learning for the various technologies. For all combined-cycle technologies, the turbine component is assumed to contribute two-thirds of the capacity, and the steam unit is assumed to contribute the remaining one-third. Therefore, building a single gigawatt (GW) of natural gas combined cycle would contribute 0.67 GW toward turbine learning and 0.33 GW toward steam learning. All non-capacity components contribute 100% toward component learning.

Table 6. Component capacity weights for new technologies

Technology	Pulverized coal	Hydrogen	Combustion turbine	HRSG	Carbon capture and sequestration	Balance of plant— turbine	Balance of plant— combined cycle
USC with 30% CCS	100%	0%	0%	0%	100%	0%	0%
USC with 90% CCS	100%	0%	0%	0%	100%	0%	0%
Combined-cycle—single-shaft	0%	0%	67%	33%	0%	0%	100%
Combined-cycle—multi-shaft	0%	0%	67%	33%	0%	0%	100%
Combined-cycle with 90% CCS	0%	0%	67%	33%	100%	0%	100%
Combustion turbine— aeroderivative	0%	0%	100%	0%	0%	100%	0%
Combustion turbine— industrial frame	0%	0%	100%	0%	0%	100%	0%
Hydrogen turbine	0%	100%	100%	0%	0%	100%	0%

Note: HRSG = heat recovery steam generator, CCS = carbon capture and sequestration

Model structure

Introduction

ECP is executed once each projection year to determine planning decisions that must be completed within the planning horizon. ECP uses a linear programming (LP) formulation to compete options for meeting future demands for electricity and complying with environmental regulations. This LP formulation selects the strategies that minimize the total present value of the investment and operating costs over a prespecified period, subject to certain conditions. These conditions include requirements that demands for electricity (accounting for seasonal and daily fluctuations variations and transmission/distribution losses) are met, minimum reliability requirements are satisfied, and emissions limits are not exceeded, and state regulations such as RPS policies are met.

ECP prepares the input data, solves the LP model, and provides the required outputs to the other submodules of EMM and modules of NEMS. The initial matrix and objective function are an input to the ECP. However, most of the coefficients in the model change over time. For instance, the objective function represents the costs of building and operating generating capacity and installing pollution control equipment, and its coefficients include capital expenditures, interest charges, and fuel costs, all of which vary over time. Similarly, coefficients in the constraint matrix, which describes the total capacity needs based on peak demands and reserve margin requirements, the allocation of available capacity to meet demands for electricity, and applicable emissions restrictions, also change during the projection horizon.

A system of equations in ECP simulates the production and transportation of coal. This formulation, which is based on the corresponding representation in the CMM, is included so that ECP determines capacity planning, operating, and emissions control decisions using a similar distribution of the availability, costs (production, transportation, and emissions control), Btu content (bituminous, subbituminous, and lignite), and emissions rates (sulfur, NO_x, Hg, and CO_2) for the coal types in the CMM.

The following section provides a mathematical description of the LP model and specifies the objective function and equations of the constraint matrix. Starting with AEO2025, the model uses the Advanced Interactive Multidimensional Modeling System (AIMMS) software to create and store coefficients in a database, solve the problem, and send the solution back to the EMM.[14] Some aspects of the coefficient calculations are still performed in the EMM Fortran code (uecp.f) but most of the calculations are in the AIMMS code. The post-processing of the LP solution remains in Fortran for AEO2025.

Key computations and equations
In ECP, decision variables include building new generating capacity (conventional and advanced, renewable and nonrenewable technologies), trading firm power (interregional and international), and installing pollution control devices at existing units. The LP model determines the appropriate mix of options that meets the environmental regulations and provides reliable and economical supplies of electricity over the planning horizon.

Reliable electricity supplies for each region are represented by a set of constraints that ensure that sufficient generating capability is available to meet the load requirements in each of the load slices and the minimum reliability requirements. Dispatchable capacity types (for example, fossil fuel, nuclear, and non-intermittent renewable technologies) can satisfy capacity and energy requirements for any or all of the load segments. Their utilization depends primarily on their availability, fuel constraints (if any), and the relative economics of the potential options. All of the load categories use a baseload generating plant type, but the first few segments use a peaking plant type. A technology may be limited to a particular mode of operation (for example, nuclear utilized in base load only), if appropriate. Dispatchable plant types receive full credit toward reliability requirements because they can be used during peak loads as long as they are not out of service for planned or unplanned outages. Energy contributions from intermittent technologies are limited to the appropriate load segments, depending on the availability of the resource (for example, wind or sun). Intermittent technologies receive a partial capacity credit depending on their capability to contribute to system reliability during peak demand hours, as described in the RFM Documentation.

Economical supplies are represented by minimizing the objective function of the LP model, which accumulates the total present value of expenditures, in nominal dollars, associated with investment and operating decisions during the planning horizon. Some of the relevant costs associated with planning horizon are incurred after the end of the 3-year planning horizon, so ECP evaluates each option on the basis of a lifecycle cost over 30 years, which is the time period used in the AEO. For instance, capital costs (for example, construction expenditures, interest charges) associated with investment decisions are recovered over the economic life of the asset. The cost coefficient for each investment decision is the sum of the present value of the annual revenue requirements (for example, depreciation or taxes) over the predefined period. Similarly, operating costs are determined for all years to consider factors such as escalating fuel costs and maintenance, refurbishment, or component replacement costs incurred for continued plant operation through the planning horizon. For each operating decision variable in the

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[14] AIMMS (Advanced Interactive Multidimensional Modeling System) is a software system designed for modeling and solving large-scale optimization and scheduling-type problems. It consists of an algebraic modeling language, an integrated development environment for both editing models and creating a graphical user interface around these models, and a graphical end-user environment.

first two years of the model, the cost coefficient is the present value of the corresponding annual fuel and operations and maintenance costs. In the last year of the planning horizon, each cost coefficient represents the sum of the present value of operating costs for years 3 through 30.

The structure of ECP is described as:

Dimensions

a	=	Activated Carbon Option
c	=	Dispatchable Capacity Type
d	=	Fuel Supply Curve Step
e	=	Export Electricity Supply Region
f	=	Fuel Choice
g	=	Import Electricity Supply Region
h	=	International Supply Region
i	=	Intermittent Renewable Technology
j	=	All Years from Year 1 to Year 3
k	=	Capacity Type Other Than Capacity Type c
l	=	Vertical Load Step Within a Season
m	=	Mode of Operation (Base, Intermediate, Peak)
n	=	Renewable Capacity Type
o	=	CSAPR Sulfur Dioxide Region (Represented by Coal Regions)
p	=	Previous Year in Planning Horizon
q	=	Avoided T&D Cost Supply Step for Distributed Generation
r	=	Electricity Market Module (EMM) Region
s	=	Season
t	=	Distributed Generation Technology Type (Base, Peak)
u	=	Unit Retrofitted with Pollution Control Devices
v	=	NOx CSAPR Region
w	=	Next Year in Planning Horizon
x	=	Retirement Group
y	=	Year in the Planning Horizon
z	=	All Years from Year y to the End of the Planning Horizon (z=y,y+1,..,3)
A	=	Cofiring Retrofit Category
B	=	Cofiring Retrofit Level
C	=	Subset of Dispatchable Capacity Types c That Are Coal-Fired
D	=	Subset of Dispatchable Capacity Types c That Are Not Coal-Fired
E	=	Short-Term Supply Step
F	=	Subset of Coal Capacity Types C Without Scrubbers
G	=	Subset of Coal Capacity Types C With Scrubbers
H	=	Current Year Coal-Fired Configuration
I	=	Coal-Fired Configuration With Emission Controls Retrofitted
J	=	Coal Supply Curves
K	=	Subset of Coal Supply Curves J That Are Subbituminous

L	=	Subset of Coal Supply Curves J That Are Lignite
M	=	Supply Curve Steps
N	=	Coal/Biomass Demand Region
O	=	Coal Capacity Group
Q	=	Carbon Containment Area
R	=	Fuel Region
S	=	Fuel Season
T	=	Fuel Transportation Step
U	=	Nuclear Capacity Group
V	=	Combined-Cycle Capacity Group
W	=	Non-Coal Fossil Steam Capacity Group
X	=	Census Division

Terms in objective function and constraints

There are three types of terms in the equations: decision variables, right-hand sides, and coefficients. These terms are described below. Before the definition of these items, the type is indicated using (D) for decision variables, (R) for right-hand sides, and (C) for coefficients.

BCF_{yrNA} = (D) Retrofit Coal-Fired Capacity for Biomass Cofiring by Cofiring Retrofit Category A in Coal/Biomass Demand Region N and EMM region r in Year y (gigawatts)

BLC_{yrRCE} = (D) Build New Coal Dispatchable Capacity Type C Beginning Operation in Year y in EMM region r and Fuel Region R at Short-Term Supply Step E (gigawatts)

BLD_{yrRDE} = (D) Build New Non-Coal Dispatchable Capacity Type D Beginning Operation in Year y in EMM region r and Fuel Region R at Short-Term Supply Step E (gigawatts)

BLN_{yrE} = (D) Build New Nuclear c Beginning Operation in Year y in EMM region r at Short-Term Supply Step E (gigawatts)

$BLST_{yr}$ = (D) Build New Demand Storage Capacity Beginning Operation in Year y in EMM region r (gigawatts)

BLX_{yeg} = (D) Build New Transmission Capacity in Year y Between Export Electricity Supply Region e and Import Electricity Supply Region g (gigawatts)

BLY_{yeg} = (D) Available New Transmission Capacity in Year y Between Adjacent Trading Regions e and g (gigawatts)

BNK_{yw} = (D) Bank Allowances for SO_2 from Year y to the Next Year w (thousands of tons)

BNK_{py} = (D) Allowances Banked for SO_2 in Previous Year p to be Used or Banked in Year y (thousands of tons)

$CARB_y$ = (C) Amount of Carbon Produced Per Unit of Biomass in Year y (thousand metric tons/trillion Btu)

$CARC_{yJR}$ = (C) Amount of Carbon Produced Per Unit of Coal from Coal Supply Region J Transported to Fuel Region R in Year y (thousand metric tons/trillion Btu)

$CARD_{yf}$ = (C) Amount of Carbon Produced Per Unit of Fuel Choice f in Year y (thousand metric tons/trillion Btu)

$CARE_y$ = (D) Total Carbon Emissions in Year y (million metric tons)

$CARI_{rQ}$ = (C) Amount of Carbon Produced Per Unit of Power Exported from EMM region r to Carbon Containment Area Q (million metric tons/billion kilowatthours)

$CARP_{yCR}$ = (C) Amount of Carbon Produced Per Unit of Coal from Coal-Fired Capacity Type C in Fuel Region R in Year y (million metric tons/trillion Btu)

$CARO_y$ = (D) Nonfossil Fuel (Renewable) Carbon Emissions in Year y (million metric tons)

$CARR_c$ = (C) Carbon Removal Rate for Capacity Type C (fraction)

$CAVD_{yrq}$ = (C) Investment Cost for New T&D Equipment Avoided by DG for Avoided T&D Cost supply step q in EMM region r in Year y

$CBCF_{yA}$ = (C) Investment Cost for Cofiring Retrofit Category A in Year y (millions of dollars/gigawatt)

$CBLC_{yrRCE}$ = (C) Investment Cost to Build Coal Capacity Type C With Initial Online Year y in EMM region r and Fuel Region R at Short-Term Supply Step E (millions of dollars/gigawatt)

$CBLD_{yrRDE}$ = (C) Investment Cost to Build Non-Coal Capacity Type D With Initial Online Year y in EMM region r and Fuel Region R at Short-Term Supply Step E (millions of dollars/gigawatt)

$CBTUB_{yr}$ = (C) Fuel Requirement to Utilize Biomass Capacity in Year y in EMM region r (trillion Btu/gigawatt)

$CBTUC_{yrCms}$ = (C) Fuel Requirement to Utilize Coal Capacity Type C in Mode of Operation m in Season s in Year y in EMM region r (trillion Btu/gigawatt)

$CBTUD_{yrDms}$ = (C) Fuel Requirement to Utilize Non-Coal Capacity Type D in Mode of Operation m in Season s in Year y in EMM region r (trillion Btu/gigawatt)

$CBT1_{yJOH}$ = (C) Allowable First-Tier Coal Transported from Coal Supply Curve J used, per Unit of Capacity, by Unit O of Unscrubbed Configuration H in Year y (trillion Btu/gigawatt)

$CBT1_{yJOI}$ = (C) Allowable First-Tier Coal Transported from Coal Supply Curve J used, per Unit of Capacity, by Unit O of Scrubbed Configuration I in Year y (trillion Btu/gigawatt)

$CCAR_y$ = (C) Carbon Allowance Price in Year y (dollars/metric ton)

$CCGC_{yO}$ = (C) Investment (Retrofit) Cost to Convert Coal-fired Steam Capacity O to Gas-Fired Steam Capacity in Year y (millions of dollars/gigawatt)

$CCSL_y$ = (R) Retrofit Limit for CCS Retrofits in Year y (gigawatts)

$CDGN_{yrt}$ = (C) Investment and Operating Cost to Build/Operate Distributed Generating Technology t Starting Operation in Year y in EMM region r (millions of dollars)

$CDVL_{yOH}$ = (C) Allowable Lignite Consumption per Unit of Capacity by Coal-Fired Unit O Operated as Unscrubbed Configuration H in Year y (trillion Btu/gigawatt)

$CDVL_{yOI}$ = (C) Allowable Lignite Consumption per Unit of Capacity by Coal-Fired Unit O Operated as Scrubbed Configuration I in Year y (trillion Btu/gigawatt)

$CDVS_{yOH}$ = (C) Allowable Subbituminous Coal Consumption per Unit of Capacity by Coal Unit O Operated as Unscrubbed Configuration H in Year y (trillion Btu/gigawatt)

$CDVS_{yOI}$ = (C) Allowable Subbituminous Coal Consumption per Unit of Capacity by Coal-Fired Generator Unit O Operated as Scrubbed Configuration I in Year y (trillion Btu/gigawatt)

$CFBTU_{yNA}$ = (C) Average Fuel Use, per Unit of Capacity, for Units of Cofiring Retrofit Category A in Coal/Biomass Demand Region N in Year y (trillion Btu/gigawatt)

$CFLEV_{AB}$ = (C) Cofiring Level for Cofiring Retrofit Category A and Cofiring Retrofit Level B (fraction)

$CFXD_{yrRD}$ = (C) Fixed Operating Costs for Non-Coal Dispatchable Capacity Type D in EMM region r and Fuel Region R (with announced retirement date) in Year y (millions of dollars/gigawatt)

$CFXDM_{yrRD}$ = (C) Fixed Operating Costs for Must-Run Non-Coal Dispatchable Capacity Type D in EMM region r and Fuel Region R (with announced retirement date) in Year y (millions of dollars/gigawatt)

$CFXDR_{yrRDx}$ = (C) Fixed Operating Costs for Non-Coal Dispatchable Capacity Type D in EMM region r and Fuel Region R (retirement Candidate) in Retirement Group x in Year y (millions of dollars/gigawatt)

$CFFX_{yA}$ = (C) Fixed Operating Costs for Cofiring Retrofit Category A in Year y (millions of dollars/gigawatt)

$CFXS_{yOI}$ = (C) Fixed Operating Costs to Utilize Coal-Fired Generator Unit O as Controlled (for example, Scrubbed) Configuration Type I in Year y (millions of dollars/gigawatt)

$CFXSM_{yOI}$ = (C) Fixed Operating Costs to Utilize Must-Run Coal-Fired Generator Unit O as Controlled (for example, scrubbed) Configuration Type I in Year y (millions of dollars/gigawatt)

$CFXU_{yOH}$ = (C) Fixed Operating Costs to Utilize Coal-Fired Generator Unit O as Uncontrolled (Unscrubbed) Configuration Type H in Year y (millions of dollars/gigawatt)

$CFXUM_{yOH}$ = (C) Fixed Operating Costs to Utilize Must-Run Coal-Fired Generator Unit O as Uncontrolled (unscrubbed) Configuration Type H in Year y (millions of dollars/gigawatt)

CGC_{yO} = (D) Convert Coal Capacity Group O to Natural Gas-Fired Steam Capacity in Year y (gigawatts)

$CGCL_{yO}$ = (D) Keep part of Coal Capacity Group as is while the remaining Coal Capacity Group is converted to Natural Gas-Fired Steam Capacity in Year y (gigawatts) when Coal-Gas Cofiring retrofit option is considered

$CGFSH$ = (C) Assumed Natural Gas Share when converting Coal Capacity to Coal-Gas Cofiring (fraction)

$CHRI_{yO}$ = (C) Investment (Retrofit) Cost for Heat Rate Improvement at Coal-Fired Generator Unit O in Year y (millions of dollars/gigawatt)

$CINT_{yriE}$ = (C) Investment and Operating Cost to Build/Operate Intermittent Technology i Starting Operation in Year y and EMM region r at Short-Term Supply Step E (millions of dollars/gigawatt)

$CNTX_{Ry}$ = (C) Cost for CO_2 Captured from the Operation of Power Plants in Census Division X As Determined by CCATS Module During year y (dollars/million metric tons)

COL_{yrC} = (R) Available Coal Capacity Type C for Year y and EMM region r (gigawatts)

$CONT_{yJOH}$ = (C) Coal Consumed per Unit of Capacity by Coal-Fired Generator Unit O Operated as Unscrubbed Configuration H Required to be Satisfied by Coal Supply Curve J in Year y (trillion Btu/gigawatt)

$CONT_{yJOI}$ = (C) Coal Consumed per Unit of Capacity by Coal-Fired Generator Unit O Operated as Scrubbed Configuration I Required to be Satisfied by Coal Supply Curve J in Year y (trillion Btu/gigawatt)

$COPB_{yrNn}$ = (C) Variable Operating Cost to Operate Biomass Renewable Capacity Type n in Coal/Biomass Demand Region N for EMM region r for Year y (million dollars/gigawatt)

$COPC_{yrRCms}$ = (C) Nonfuel Operating Costs to Utilize Non-Must Run Coal Capacity Type C in Operating Mode m in Season s in EMM region r and Fuel Region R in Year y (million dollars/gigawatt)

$COPCM_{yrRCms}$ = (C) Nonfuel Operating Costs to Utilize Must-Run Coal Capacity Type C in Operating Mode m in Season s in EMM region r and Fuel Region R in Year y (million dollars/gigawatt)

$COPD_{yrRDfms}$ = (C) Variable Operating Cost to Operate Non-Coal Dispatchable Capacity Type D Using Fuel Choice f in Operating Mode m in Season s for Year y and EMM region r and Fuel Region R (million dollars/gigawatt)

$COPDM_{yrRDfms}$ = (C) Variable Operating Cost to Operate Non-Coal Must-Run Dispatchable Capacity Type D Using Fuel Choice f in Mode m in Season s for Year y and EMM region r and Fuel Region R (million dollars/gigawatt)

$COPH_{yrl}$ = (C) Variable Operating Cost to Operate Hydro Capacity in Load Step l for Year y and EMM region r (million dollars/gigawatt)

$COPR_{yrn}$ = (C) Variable Operating Cost to Operate Non-Biomass Renewable Capacity Type n for Year y and EMM region r (million dollars/gigawatt)

$CPLIM_{yCE}$ = (R) Short-Term Capacity Limit for Dispatchable Capacity Type C for Year y and Short-Term Supply Step E (gigawatts)

$CPLIM_{yiE}$ = (R) Short-Term Capacity Limit for Intermittent Type i for Year y and Short-Term Supply Step E (gigawatts)

$CPLIM_{ynE}$ = (R) Short-Term Capacity Limit for Renewable Type n for Year y and Short-Term Supply Step E (gigawatts)

$CPMR_{rc}$ = (C) Amount of Time Required for Planned maintenance for Capacity Type C in EMM region r (thousands of hours)

$CRET_{yOHI}$ = (C) Investment (Retrofit) Cost to Convert Coal-Fired Generator Unit O From Uncontrolled Configuration H to Controlled Configuration I in Year y (millions of dollars/gigawatt)

$CRCC_{yV}$ = (C) Investment Cost to Retrofit Existing Combined-Cycle Capacity Group V with Carbon Capture and Sequestration Equipment in Year y (millions of dollars/gigawatt)

$CDST_{yrE}$ = (C) Investment Cost to Build Battery/Diurnal Storage Beginning Operation in Year y in EMM region r at Short-Term Supply Step E (millions of dollars/gigawatt)

$CRNW_{yrNE}$ = (C) Investment Cost to Build Renewable Capacity Type N With Initial Online Year y in EMM region r at Short-Term Supply Step E (millions of dollars/gigawatt)

$CTRB_{yABNC}$ = (C) Transportation (Incremental) Cost to Cofire with Biomass for Cofiring Retrofit Category A and Cofiring Retrofit Level B in Coal Capacity Type C in Coal Region N in Year y (million dollars/trillion Btu)

$CTRE_{yegsl}$ = (C) Cost of Transferring Electricity from EMM region e to EMM region g in Season s and Vertical Load Step l in Year y (millions of dollars/gigawatt)

$CTRN_{yRST}$ = (C) Transportation Cost to Use Natural Gas in Fuel Season S in Fuel Region R at Fuel Transportation Step T in Year y (million dollars/trillion Btu)

$CTRO_{yRT}$ = (C) Transportation Cost to Use Oil in Fuel Region R at Fuel Transportation Step T in Year y (million dollars/trillion Btu)

$CTR1_{yJNCa}$ = (C) Tier 1 Transportation and Activated Carbon Cost to Use Coal from Supply Curve J to Coal/Biomass Demand Region N Used in Coal-Fired Capacity Type C with Activated Carbon Level a in Year y (million dollars/trillion Btu)

$CTR2_{yJNC}$ = (C) Incremental Transportation Cost for Tier 2 Coal from Supply Curve J to Coal/Biomass Demand Region N Used in Capacity Type C in Year y (million dollars/trillion Btu)

$CUNS_{yJN}$ = (R) Contract Amount for Minimum Coal for Unscrubbed Plants Transported from Supply Curve J to Coal/Biomass Demand Region N in Year y (trillion Btu)

DGN_{yrqt} = (D) Build/Utilize Distributed Generation Type t and Avoided T&D Cost Supply Step q Beginning Operation in Year y in EMM region r (gigawatts)

$DGNL_{yrq}$ = (R) Amount of New Capacity that Can Be Met by Distributed Generation for Avoided T&D Cost Supply Step q in Year y and EMM region r (gigawatts)

DST_{yrE} = (D) Build/Utilize Battery/Diurnal Storage Beginning Operation in Year y in EMM region r at Short-Term Supply Step E (gigawatts)

ECF_{yrNA} = (D) Existing Coal-Fired Capacity Retrofitted for Biomass Cofiring by Cofiring Retrofit Category A in Coal/Biomass Demand Region N and EMM region r in Year y (gigawatts)

ELA_{yrCmsl} = (C) Derating Factor (Adjustment for Forced Outage, Planned maintenance, and Load Following Rates) for Coal Capacity Type C Allocated to Meet Capacity Requirements in Season s and Vertical Load Step l in Year y, EMM region r in Operating Mode m (fraction)

ELA_{yrDmsl} = (C) Derating Factor (Adjustment for Forced Outage, Planned maintenance, and Load Following Rates) for Non-Coal Dispatchable Capacity Type D Allocated to Meet Capacity Requirements in Season s and Vertical Load Step l in Year y, EMM region r in Mode m (fraction)

ELB_{yrs} = (C) Derating Factor (Adjustment for Forced Outage, Planned maintenance, Load Following Rates, and Availability of Resource) for Biomass Capacity Allocated to Meet Capacity Requirements in Season s in Year y and EMM region r (fraction)

ELC$_{yrls}$ = (R) Capacity Requirement in the Vertical Load Step l in Season s in Year y and EMM region r (gigawatts)

ELD$_{yrt}$ = (C) Derating Factor corresponding to Mode of Operation (Base, Peak) for Distributed Generation Technology Type t in EMM region r in Year y (fraction)

ELXDS$_{rsl}$ = (C) Derating Factor (Availability of Resource) for Existing Diurnal Storage/Batteries in Season s and Vertical Load Step l in EMM region r, (Fraction). The sign can be either positive or negative depending on net contribution from charging (-) or discharging (+) during the vertical load step I.

ELDS$_{yrslE}$ = (C) Derating Factor (Availability of Resource) for New Diurnal Storage/Batteries in Season s and Vertical Load Step l Supply Step E In EMM region r, Beginning Operation in Year y (Fraction). The sign can be either positive or negative depending on net contribution from charging (-) or discharging (+) during the vertical load step I.

ELI$_{yrisIE}$ = (C) Derating Factor (Availability of Resource) for Intermittents in Season s and Vertical Load Step in Short Supply Step E In EMM region r By Intermittent Technology Type i Beginning Operation in Year y (fraction)

ELXI$_{risl}$ = (C) Derating Factor (Availability of Resource) for Existing Intermittents in Season s and Vertical Load Step l In EMM region r By Intermittent Technology Type i (fraction)

ELN$_{yr}$ = (C) Derating Factor (Adjustment for Forced Outage, Planned maintenance, Load Following Rates, and Availability of Resource) for Nuclear Capacity Allocated to Meet Capacity Requirements in Year y and EMM region r (fraction)

ELR$_{yrn}$ = (C) Derating Factor (Adjustment for Forced Outage, Planned maintenance, Load Following Rates, and Availability of Resource) for Renewable Capacity Allocated to Meet Capacity Requirements in Year y, EMM region r By Renewable Capacity Type n (fraction)

EXC$_{yrO}$ = (R) Available Capacity for Coal-Fired Capacity Group O Year y (gigawatts)

EXCC$_{yV}$ = (R) Available Capacity for Combined-Cycle Capacity Group V in Year y (gigawatts)

EXD$_{yrD}$ = (D) Existing Non-Coal Dispatchable Capacity Type D (Announced Retirements) in Year y in EMM region r (gigawatts)

EXDM$_{yrD}$ = (D) Existing Must-Run, Non-Coal Dispatchable Capacity Type D in Year y in EMM region r (gigawatts)

EXDR$_{yrDx}$ = (D) Existing Non-Coal Dispatchable Capacity Type D (Retirement Candidate) in Retirement Group x in Year y in EMM region r (gigawatts)

EXDS$_{yr}$ = (D) Existing Battery Storage Capacity in Year y in EMM region r (gigawatts)

$EXFS_{yW}$ = (R) Available Capacity for Non-Coal Fossil Steam Capacity Group W in Year y (gigawatts)

EXH_{yr} = (D) Existing Hydro Energy in Year y in EMM region r (gigawatthours)

EXI_{yrI} = (D) Existing Intermittent Capacity Type I in Year y in EMM region r (gigawatts)

EXP_{yesl} = (R) Electric Power Export Limit in Season s and Vertical Load Step l in Year y and EMM Export Region e (gigawatts)

EXR_{yrn} = (D) Existing Renewable Capacity Type n in Year y in EMM region r (gigawatts)

EXS_{yrRD} = (C) Share of Existing Non-Coal Dispatchable Capacity Type D in Year y in EMM region r that is located in Fuel Region R (fraction)

$EXSM_{yrRD}$ = (C) Share of Existing Must-Run, Non-Coal Dispatchable Capacity Type D in Year y in EMM region r that is located in Fuel Region R (fraction)

$EXSR_{yrRD}$ = (C) Share of Existing Non-Coal Dispatchable Capacity Type D (Announced Retirements) in Year y in EMM region r that is located in Fuel Region R (fraction)

$EXST_{yr}$ = (D) Existing Demand Storage Capacity in Year y in EMM region r (gigawatts)

EXT_{yegs} = (R) Interregional Transfer Capacity in Season s in Year y and EMM Adjacent Trading Regions e and g (gigawatts)

$FGDL_y$ = (R) Retrofit Limit for Scrubber Retrofits in Year y (gigawatts)

GEL_{yr} = Total Generation for EMM region r in Year y (billion kilowatthours)

$GRPS_{yeg}$ = (D) Renewable Energy Credits Transferred from EMM region e to EMM region g in Year y (billion kilowatthours)

HRI_{yOH} = (D) Heat Rate Improvement for Coal Capacity Group O in Year y for Current Emissions Controls Configuration H (gigawatts)

HRI_{yOI} = (D) Heat Rate Improvement for Coal Capacity Group O in Year y for Retrofitted Emissions Controls Configuration I (gigawatts)

$HRTE_{yrc}$ = (C) Heat Rate for Capacity Type C in EMM region r in Year y (Btu/kilowatthour)

HRC_{yNC} = (C) Heat Rate for Coal Capacity Type C in Coal/Biomass Demand Region N in Year y (Btu/kilowatthour)

$ISHR_i$ = (C) Amount of Generation for Intermittent Capacity Type i That is Counted Toward Minimum Generation Requirement (fraction)

IMP_{ygsl} = (R) Electricity Import Limit in Season s and Load Slice l in Year y and EMM Import Region g (gigawatts)

INT_{yriE} = (D) Build/Utilize Intermittent Renewable Type i Beginning Operation in Year y in EMM region r at Short-Term Supply Step E (gigawatts)

$INTL_{ir}$ = (R) Intermittent Build Limit for Intermittent Technology i and EMM region r (gigawatts)

$LCAR_{yQ}$ = (R) Carbon Emission Limit for CO_2 Containment Area Q and for Year y (million metric tons)

$LHRS_l$ = (C) Hours in Vertical Load Segment l (thousands of hours)

$LMERC_y$ = (R) Mercury Emission Limit for Year y (tons)

$LNOX_{yv}$ = (R) NO_X Emission Limit for NO_X CSAPR Region v and for Year y (million tons)

$LSO2_{yN}$ = (R) CSAPR SO_2 Limit for Coal Region N in Year y (thousand tons)

$LSO2V_{yN}$ = (R) CSAPR SO_2 Variability Limit for Coal Region N in Year y (thousand tons)

MAX_{yJ} = (R) Maximum Production for Coal Supply Curve J in Year y (trillion Btu)

$MERC_{yJNCa}$ = (C) Amount of Mercury in Coal from Supply Curve J Used in Coal Capacity in Coal/Biomass Demand Region N in Coal Capacity Type C With Activated Carbon Option a in Year y (tons/trillion Btu)

$MERCE_{yoC}$ = (D) Mercury Emissions from Coal Capacity Type C in SO_2 Region o in Year y (thousandths of tons)

$MERCE_{yoD}$ = (D) Mercury Emissions from Non-Coal Capacity Type D in SO_2 Region o in Year y (thousandths of tons)

$MERD_{yrDfms}$ = (C) Amount of Mercury Produced Per Unit of Electricity Generated in EMM region r By Non-Coal Dispatchable Capacity Type D With Fuel f In Operating Mode m in Season s in Year y (tons/gigawatt)

$NOXC_{NCms}$ = (C) Amount of NO_X Produced per Unit of Electricity Generated by Coal Capacity Type C in Coal/Biomass Demand Region N in Operating Mode m and in Season s (millions of tons/gigawatt)

$NOXD_{Dfms}$ = (C) Amount of NOx Produced per Unit of Electricity Generated by Non-Coal Dispatchable Capacity Type D with Fuel f in Operating Mode m and in Season s (millions of tons/gigawatt)

$NOXE_{yvC}$ = (D) NO_X Emissions from Coal Capacity Type C in NOx CSAPR Region v in Year y (thousand tons)

$NOXE_{yvD}$ = (D) NO_X Emissions from Non-Coal Capacity Type D in NOx CSAPR Region v in Year y (thousand tons)

NOXR_{yvHI} = (C) Reduction in Amount of NOx Produced as a Result of Converting Uncontrolled (Unscrubbed) Existing Coal Configuration H to Controlled (Scrubbed) Configuration I by Retrofitting NO_X Controls in NO_X CSAPR Area v in Year y (millions of tons/gigawatt)

NOXX_{yvC} = (D) NO_X Emissions Reductions from Retrofitting Uncontrolled Coal Capacity Type C in NO_X CSAPR Region v in Year y (thousand tons)

NTX_{Xy} = (D) Amount of CO_2 Captured by Power Plants in Census Division X in Year y (million metric tons)

NUC_{yU} = (R) Available Capacity for Nuclear Capacity Group U in Year y (gigawatts)

OPB_{yrR} = (D) Utilize Biomass Renewable Capacity in Year y in EMM region r and Fuel Region R (gigawatts)

OPC_{yrRCms} = (D) Utilize Non-Must-Run Coal Capacity Type C in Operating Mode m in Season s in Year y in EMM region r and Fuel Region R (gigawatts)

OPCM_{yrRCms} = (D) Utilize Must-Run Coal Capacity Type C in Operating Mode m in Season s in Year y in EMM region r and Fuel Region R (gigawatts)

$\text{OPD}_{yrRDfms}$ = (D) Utilize Non-Coal Dispatchable Capacity Type D Consuming Fuel f in Mode m in Season s in Year y in EMM region r and Fuel Region R (gigawatts)

$\text{OPDM}_{yrRDfms}$ = (D) Utilize Must-Run Non-Coal Dispatchable Capacity Type D Consuming Fuel f in Operating Mode m in Season s in Year y in EMM region r and Fuel Region R (gigawatts)

OPH_{yrl} = (D) Utilize Hydro Capacity in Vertical Load Step l in Year y in EMM region r (gigawatts)

OPR_{yrn} = (D) Utilize Non-Biomass Renewable Capacity Type n in Year y in EMM region r (gigawatts)

OTH_{yJ} = (D) Other Coal (Nonutility) Demand Satisfied from Coal Supply Curve J in Year y (trillion Btu)

PBM_{yNd} = (C) Production/Transportation Cost for Biomass Consumed to Generate Electricity on Supply Step d in Biomass Region N in Year y (dollars/million Btu)

PCL_{yJM} = (C) Production Cost for Coal from Supply Curve J and Coal Supply Step M in Year y (trillion Btu)

PH2_{yXSd} = (C) Production Cost for Hydrogen Gas Consumed to Generate Electricity in Census Division Xon Supply Step d in Season S in Year y (dollars/million Btu)

PINT_{yr} = (C) Maximum Allowable Share of Total Generation for Intermittent Technologies in Year y in EMM region r (trillion Btu)

PMC$_{yscr}$ = (D) Planned maintenance Scheduled for Capacity Type C in EMM region r in Season s in Year y (gigawatts)

PMM$_{yscr}$ = (D) Planned maintenance Scheduled for Must-Run Capacity Type C in EMM region r in Season s in Year y (gigawatts)

PNG$_{yd}$ = (C) Production Cost for Natural Gas Consumed to Generate Electricity on Supply Step d in Year y (dollars/million Btu)

POL$_{yd}$ = (C) Production Cost for Oil Consumed to Generate Electricity on Supply Step d in Year y (dollars/million Btu)

QBM$_{yNd}$ = (D) Quantity of Biomass Fuel Consumed for Supply Step d in Biomass Region N in Year y (trillion Btu)

QCL$_{yJM}$ = (D) Quantity of Coal Produced from Supply Curve J and Supply Step M in Year y (trillion Btu)

QH2$_{yXSd}$ = (D) Quantity of Hydrogen Gas Produced in Census Division X for Supply Step d in Season S in Year y (trillion Btu)

QNG$_{yd}$ = (D) Quantity of Natural Gas Produced for Supply Step d in Year y (trillion Btu)

QOL$_{yd}$ = (D) Quantity of Oil Produced for Supply Step d in Year y (trillion Btu)

RCC$_{yV}$ = (D) Retrofit Combined-Cycle Group V with Carbon Capture and Sequestration in Year y (gigawatts)

RGS$_{yr}$ = (R) Regional SO$_2$ Emissions Limits for Year y and EMM region r (million tons)

RMC$_{yrc}$ = (C) Contribution Made to Satisfying the Reserve Margin Made by Dispatchable Capacity Build Type c Beginning Operation in Year y for EMM region r (fraction)

RMD$_{yrt}$ = (C) Contribution Made to Reserve Margin Made by Distributed Generation Type t in Year y for EMM region r (fraction)

RMI$_{yri}$ = (C) Contribution Made to Satisfying the Reserve Margin Made by Intermittent Technology I Beginning Operation in Year y for EMM region r (fraction, 0.0 = resource never available at peak, 1.0 = resource is always available at peak)

RMIN$_y$ = (C) Amount of Total Generation or Sales That Must Be Provided by Renewable Technologies (fraction)

RMQ$_{yr}$ = (R) Total Capacity Requirement Including a Reserve Margin in Year y and EMM region r (gigawatts)

RMR$_{yrn}$ = (C) Contribution Made to Satisfying the Reserve Margin Made by Renewable Capacity Build Type n Beginning Operation in Year y for EMM region r (fraction)

RMS_{yr} = (C) Contribution Made to Satisfying the Reserve Margin Made by Storage Capacity Beginning Operation in Year y for EMM region r (fraction)

RNW_{yrnE} = (D) Build New Renewable Capacity Type n Beginning Operation in Year y in EMM region r at Short-Term Supply Step E (gigawatts)

$RNWL_{nr}$ = (R) Renewable Build Limit for Renewable Capacity Type n and EMM region r (gigawatts)

$RPSP_y$ = (C) Renewable Portfolio Standard (RPS) Requirement in Year y (fraction)

$RPSR_{yr}$ = (D) Regional RPS Generation in Region r in Year y (billion kilowatthours)

$RSHR_n$ = (C) Amount of Generation for Renewable Capacity Type n That is Counted Toward Minimum Generation Requirement (fraction)

$SHOURS_s$ = (C) Hours in Season s (thousands of hours)

$SNH2_{yRDf}$ = (C) Fuel Share for Hydrogen Gas in Non-Coal Dispatchable Type D Using Fuel Type f in Fuel Region R in Year y (fraction)

SNG_{yRDf} = (C) Fuel Share for Natural Gas in Non-Coal Dispatchable Type D Using Fuel Type f in Fuel Region R in Year y (fraction)

$SNGM_{yRDf}$ = (C) Fuel Share for Natural Gas in Non-Coal, Must-Run Dispatchable Type D using Fuel Type f in Fuel Region R in Year y (fraction)

$SO2C_{yJRC}$ = (C) Amount of SO_2 Produced Per Unit of Coal Transported from Supply Region J to Fuel Region R For Coal Capacity Type C in Year y (thousand tons/trillion Btu)

$SO2D_{yRf}$ = (C) Amount of SO_2 Produced Per Unit of Fuel f Transported to Fuel Region R in Year y (thousand tons/trillion Btu)

$SO2E_{yoC}$ = (D) SO_2 Emissions from Coal Capacity Type C in SO_2 Region o in Year y (thousand tons)

$SO2E_{yoD}$ = (D) SO_2 Emissions from Non-Coal Capacity Type D in SO_2 Region o in Year y (thousand tons)

$SO2T_{yoN}$ = (D) CSAPR SO_2 Emissions Traded from Coal Region o to Coal Region N in Year y (thousand tons)

$SRCR_C$ = (C) Share of Excess Capacity of Capacity Type C Committed to Load That is Credited Against the Spinning Reserve Requirement (fraction)

SRE_{yegsl} = (D) Spinning Reserved Transferred from Export Region e to Import Region g in Season s and Load Slice l in Year y (gigawatts)

$SRINT_i$ = (C) Fraction of Derated Intermittent Capacity i That Must Be Matched with Spinning Reserves (fraction)

$SRRD_r$ = (C) Difference Between Seasonal Peak and Load Height Required for Spinning Reserve in EMM Region r (fraction)

$SRRH_r$ = (C) Share of Load Height Required for Spinning Reserve in EMM Region r (fraction)

$SRTC$ = (C) Share of Transmission Capacity That is Credited Against Spinning Reserve Requirement (fraction)

$SRXDS_{rsl}$ = (C) Availability of Resource to Contribute to Spinning Reserves for Existing Diurnal Storage/Batteries in Season s and Vertical Load Step l In EMM region r (Fraction).

$SRDS_{yrslE}$ = (C) Availability of Resource to Contribute to Spinning Reserves for New Diurnal Storage/Batteries in Season s and Vertical Load Step l at Short-term Supply Step E In EMM region r, Beginning Operation in Year y (Fraction).

$SRPVH_{yrsl}$ = (C) Availability of Resource to Contribute to Spinning Reserves for Storage Component of Photovoltaic Battery Hybrid Technology in Season s and Vertical Load Step l In EMM region r, Beginning Operation in Year y (Fraction).

STD_{yNC} = (D) Use Coal Stocks in Coal Capacity Type C in Coal Region N in Year y (trillion Btu)

$STFAC_i$ = (C) Generation Replacement Factor for Storage Technology Type i (fraction)

$STLIM_{yr}$ = (R) Capacity Limit on Demand Storage Technology in EMM region r and Year y (gigawatts)

STU_{yNC} = (D) Store Coal Stocks in Coal Capacity Type C in Coal Region N in Year y (trillion Btu)

STX_{yrsl} = (D) Demand Storage Replaced in Region r, Season s and Load Segment l, in Year y (gigawatts)

TBM_{yrNABC} = (D) Quantity of Biomass Transported to Capacity Type C and Cofiring Category A with Cofiring Level B in Coal/Biomass Region N and EMM region r in Year y (trillion Btu)

$TBMBT_{yNW}$ = (D) Quantity of Biomass Fuel W Consumed for Biomass to Liquids in Coal Region N in Year y (trillion Btu)

$TBMET_{yNW}$ = (D) Quantity of Biomass Fuel W Consumed for Ethanol Production in Coal Region N in Year y (trillion Btu)

$TBMHY_{yNW}$ = (D) Quantity of Biomass Fuel W Consumed for Hydrogen Production in Coal Region N in Year y (trillion Btu)

$TBMIN_{yNW}$ = (D) Quantity of Biomass Fuel W Consumed by the Industrial Sector in Coal Region N in Year y (trillion Btu)

TCL_{yJNCa} = (D) Quantity of Coal Transported from Supply Curve J to Coal Region N Used in Capacity Type C With Activated Carbon Level a in Year y (trillion Btu)

$TC2_{yJNC}$ = (D) Quantity of Coal Transported at Additional Coal (Tier 2) Cost from Supply Curve J to Coal Region N Used in Coal Capacity Type C in Year y (trillion Btu)

$TDER$ = (C) Capacity Derate Factor for Interregional Transmission (fraction)

$TDLS_{yr}$ = (C) Transmission Loss Factor for Region r in Year y (fraction)

TFL_{yRDfS} = (D) Quantity of Fuel Type f Used by Non-Coal Non Must-Run Dispatchable Capacity Type D Fuel Region R in Fuel Season S in Year y (trillion Btu)

$TFLM_{yRDfS}$ = (D) Quantity of Fuel Type f Used by Non-Coal Must-Run Dispatchable Capacity Type D Fuel Region R in Fuel Season S in Year y (trillion Btu)

$TLOSS_{yer}$ = (C) 1 - Interregional Transmission Loss Factor from Export Region e to EMM Region r in Year y (fraction)

TNG_{yRST} = (D) Quantity of Natural Gas Transported to Fuel Region R for Transportation Step T in Fuel Season S in Year y (trillion Btu)

TOL_{yRT} = (D) Quantity of Oil Transported to Fuel Region R for Transportation Step T in Year y (trillion Btu)

TRE_{yegsl} = (D) Electric Power Transferred from Export Region e to Import Region g in Season s and Load Slice l in Year y (gigawatts)

$TRECN_{yegsl}$ = (D) Electric Power Transferred from Canadian Export Region e to EMM Import Region g in Season s and Load Slice l in Year y (gigawatts)

$UNCC_{yV}$ = (D) Allocate Existing Combined-Cycle Capacity Group V in Year y (gigawatts)

$UNFS_{yW}$ = (D) Allocate Existing Non-Coal Fossil Steam Capacity Group W in Year y (gigawatts)

$UNIT_{yOH}$ = (D) Allocate Existing Coal-Fired Capacity Group O With Current Configuration Type H in Year y (gigawatts)

$UNIT_{yOI}$ = (D) Allocate Existing Coal-Fired Capacity Group O With Retrofitted Emissions Controls Configuration Type I in Year y (gigawatts)

$UNTM_{yOH}$ = (D) Allocate Existing Must-Run Coal-Fired Capacity Group O With Current Configuration Type H in Year y (gigawatts)

$UNTM_{yOI}$ = (D) Allocate Existing Must-Run Coal-Fired Capacity Group O With Retrofitted Emissions Controls Configuration Type I in Year y (gigawatts)

The decision variables are the outputs of ECP. The operate, or utilize, variables for coal-fired generator units (OPC_{yrNCms}) represent the choices to consume coals from different supply curves. Some coal-fired plants may also have the option of cofiring with biomass (wood and waste products). For non-coal dispatchable technologies, the corresponding decision ($OPD_{yrRDfms}$) considers fuel switching between the available fuel types f. For dual-fired units, this decision involves switching between alternative fuels such as oil and natural gas. The ECP can decide to utilize a dispatchable technology over some or all of the load segments (base, intermediate, and peak).

The available capacity for coal-fired generator units is represented by the variables $UNIT_{yOH}$ and $UNIT_{yOI}$. Units with announced retirement dates are available until the scheduled retirement occurs. The remaining units can be retired by ECP. This capacity is available for the entire planning horizon unless the costs of continuing operation exceed the corresponding revenues and replacement capacity is more economical. Two decision variables are used for existing non-coal dispatchable capacity (EXD_{yrRD} and $EXDR_{yrRDx}$). The first variable describes units with announced retirement dates. The second variable represents capacity that can be retired by ECP if less expensive supplies can be built. Separate variables are also required for the utilization and addition of both the coal and non-coal dispatchable capacity because these capacity types involve decisions about their mode of operation. A similar structure could be used for intermittent technologies, but it is unnecessary because the utilization of the capacity is not a decision variable but is determined by the availability of the renewable resource. Combining the decision variables reduces the size of the model.

A second set of operate vectors are included for must-run capacity, which is not dispatched on an economic basis. Although these plants typically have high operating costs, they have been utilized historically for a variety of reasons, such as relieving transmission congestion, satisfying fixed contracts, or providing a secondary product (cogeneration). Because of these considerations, these plants are assumed to be characterized by a minimum generation requirement, and they are not considered for retirement during a specified time. The end date of the must-run status can be specified by plant as an input or updated in the code based on policy switches under different scenarios. For must-run coal-fired plants, the operate variables are represented by $OPCM_{yrRCms}$ and the available capacity is defined by $UNTM_{yOH}$ and $UNTM_{yOI}$. For non-coal dispatchable technologies available, the respective operate and capacity variables are specified by $OPDM_{yrRDfms}$ and $EXDM_{yrRD}$.

The formulation does not explicitly represent intermittent technologies coupled with a back-up source of power, but it effectively determines the appropriate technology mix to meet system needs for energy and reliability. If additional capacity is needed to meet reliability requirements and an intermittent technology without a full capacity credit (in other words, contribution to reserve margin is determined by its ability to generate power during peak load) is economical, then another capacity type will also have to be built. This structure will allow additions of intermittent technologies when a capacity surplus exists, as long as the resulting fuel savings offset the capital investment. In the case of PV, EMM represents a hybrid technology with both PV and integrated 4-hour battery storage. This combines operating characteristics of both types. Energy is dispatched within the energy limits of the system and capacity credit is calculated as discussed in the RFM documentation. Otherwise, the model is free to pair wind or solar capacity with appropriate dispatchable generation and storage to provide the least-cost approach to meeting seasonal and diurnal energy demands and providing for system reliability.

Distributed generation technologies are assumed to be built for two modes of operation: base and peak. The utilization rates for baseload and peaking units are assumed to be 50% and 5%, respectively. Compared with central-station plants, distributed generation capacity typically has higher construction and operating costs, but it may be economical because it reduces the need for investment in new transmission and distribution (T&D) equipment. The amount of incremental T&D expenditures avoided by distributed generation varies by region because it depends on the distribution of load. A supply curve is used to describe the quantity and cost of new investment that would be unnecessary because of distributed generation.

Objective function

The objective function to be minimized in the planning component is the total discounted present value of the costs of meeting demand and complying with environmental regulations during the entire planning horizon. All costs are in nominal dollars, and the inflation rate is determined using the gross domestic product (GDP) implicit price deflator. The coefficient of each decision variable represents the present value of that particular cost component, discounted to the current projection year. The total cost includes both investment costs associated with changes in capital stock and variable costs that result from the operation of the available generating capability. Cost components in the objective function include the following:

- Operation (fixed) plus retrofit (if any) costs of existing uncontrolled coal-fired generator units ($CFXU_{yOH}$ • $UNIT_{yOH}$ and • $UNTM_{yOH}$) and controlled units ($CFXS_{yOI}$ • $UNIT_{yOI}$ and $CFXSM_{yOI}$ • $UNTM_{yOI}$)

- Operation (fixed) of existing non-coal dispatchable capacity types ($CFXD_{yrRD}$ • EXD_{yrRD}, $CFXDM_{yrRD}$ • $EXDM_{yrRD}$ and $CFXDR_{yrRDx}$ • $EXDR_{yrRDx}$)

- Operation (fixed) costs for cofiring with biomass in coal capacity types to cofire with biomass ($CFFX_{yA}$ • ECF_{yNA} and $CFFX_{yA}$ • BCF_{yNA})

- Production costs for coal, natural gas, Hydrogen, oil, and biomass (PCL_{yJM} • QCL_{yJM}, PNG_{yd} • QNG_{yd}, $PH2_{yXSd}$ • $QH2_{yXSd}$, POL_{yd} • QOL_{yd}, and PBM_{yNd} • QBM_{yNd})

- Transportation and activated carbon costs for delivering coal for Tier-1 ($CTR1_{yJNCa}$ • TCL_{yJNCa}) and Tier-2 ($CTR2_{yJNC}$ • $TC2_{yJNC}$) rates

- Transportation costs for delivering natural gas and oil ($CTRN_{yRST}$ • TRN_{yRST} and $CTRO_{yRST}$ • TRO_{yRST})

- Transportation (incremental) costs for cofiring with biomass ($CTRB_{yAB}$ • TBM_{yrNABC})

- Operation (variable) costs for coal capacity types ($COPC_{yrRCms}$ • OPC_{yrRCms} and $COPCM_{yrRCms}$ • $OPCM_{yrRCms}$)

- Operation (variable) costs for non-coal dispatchable capacity types ($COPD_{yrRDfms}$ • $OPD_{yrRDfms}$ and $COPDM_{yrRDfms}$ • $OPDM_{yrRDfms}$)

- Operation of non-hydro renewable capacity types ($COPR_{yrn}$ • OPR_{yrn} and $COPB_{yrR}$ • OPB_{yrR})

- Operation of hydro capacity ($COPH_{yrl}$ • OPH_{yrl})

- Construction of new dispatchable capacity types ($CBLD_{yrRcE}$ • BLD_{yrRcE})

- Construction and operation of intermittent renewable technologies ($CINT_{yriE}$ • INT_{yriE})

- Construction and operation of diurnal/battery storage technologies (CDST$_{yrE}$ • DST$_{yrE}$)

- Construction of new renewable capacity types (CRNW$_{yrnE}$ • RNW$_{yrnE}$).

- Construction of new interregional transmission capacity between regions (CBLX$_{yeg}$ • BLX$_{yeg}$)

- Construction of new distributed generation capacity, adjusted for avoided transmission and distribution expenditures ({CDGN$_{yrt}$ - CAVD$_{yrq}$} • DGN$_{yrqt}$)

- Investment costs to retrofit existing coal capacity to cofire with biomass (CBCF$_{yA}$ • BCF$_{yNA}$)

- Investment costs to retrofit existing coal capacity with emissions controls (CRET$_{yOHI}$ • UNIT$_{yOH}$)

- Investment costs for heat rate improvement of existing coal capacity with current configuration (CHRI$_{yO}$ • HRI$_{yOH}$)

- Investment costs for heat rate improvement of existing coal capacity with retrofitted emissions controls configuration (CHRI$_{yO}$ • HRI$_{yOI}$)

- Investment costs to convert existing coal capacity to natural gas (CCGC$_{yO}$ • CGC$_{yO}$) or coal and gas cofiring (CCGC$_{yO}$ • CGC$_{yO}$ + CCGC$_{yO}$ • CGCL$_{yO}$)

- Investment costs to retrofit existing combined-cycle capacity with CCS equipment (CRCC$_{yV}$ • RCC$_{yV}$)

- Transfer of electricity between regions (CTRE$_{yegsI}$ • TRE$_{yegsI}$)

- Cost of purchasing carbon allowances (CCAR$_y$ • CARE$_y$)

- Net Cost of transporting CO_2 from power plants to Census division for EOR or saline storage (CNTX$_{Xy}$ • NTX$_{Xy}$)

The objective function is expressed as follows:

(3-1) MIN

$$
\begin{aligned}
[&\sum_y \sum_O \sum_H CFXU_{yOH} \cdot UNIT_{yOH} + \sum_y \sum_O \sum_I CFXS_{yOI} \cdot UNIT_{yOI} \\
&+ \sum_y \sum_O \sum_H CFXUM_{yOH} \cdot UNIT_{yOH} + \sum_y \sum_O \sum_I CFXSM_{yOI} \cdot UNIT_{yOI} \\
&+ \sum_y \sum_r \sum_D \sum_x CFXD_{yrDx} \cdot EXD_{yrDx} + \sum_y \sum_r \sum_D \sum_x CFXDM_{yrDx} \cdot EXDM_{yrDx} \\
&+ \sum_y \sum_r \sum_D \sum_x CFXDR_{yrDx} \cdot EXDR_{yrDx} + \sum_y \sum_N \sum_A CFFX_{yA} \cdot ECF_{yNA} + \sum_y \sum_N \sum_A CFFX_{yA} \cdot BCF_{yNA} \\
&+ \sum_y \sum_J \sum_M PCL_{yJM} \cdot QCL_{yJM} + \sum_y \sum_d PNG_{yd} \cdot QNG_{yd} + \sum_y \sum_d POL_{yd} \cdot QOL_{yd} \\
&+ \sum_y \sum_{O''} \sum_S \sum_d PH2_{yXSd} \cdot QH2_{yXSd} \\
&+ \sum_y \sum_N \sum_d PBM_{yNd} \cdot QBM_{yNd} + \sum_y \sum_J \sum_N \sum_C \sum_a CTR1_{yJNCa} \cdot TCL_{yJNCa} \\
&+ \sum_y \sum_J \sum_N \sum_C CTR2_{yJNC} \cdot TC2_{yJNC} + \sum_y \sum_R \sum_S \sum_T CTRN_{yRST} \cdot TNG_{yRST} \\
&+ \sum_y \sum_R \sum_T CTRO_{yRT} \cdot TOL_{yRT} + \sum_y \sum_r \sum_N \sum_A \sum_B \sum_C CTRB_{yAB} \cdot TBM_{yrNABC} \\
&+ \sum_y \sum_r \sum_R \sum_C \sum_m \sum_s COPC_{yrRCms} \cdot OPC_{yrRCms} + \sum_y \sum_r \sum_R \sum_C \sum_m \sum_s COPCM_{yrRCms} \cdot OPCM_{yrRCms} \\
&+ \sum_y \sum_r \sum_D \sum_m \sum_s \sum_f COPD_{yrRfms} \cdot OPD_{yrRfms} + \sum_y \sum_r \sum_D \sum_m \sum_s \sum_f COPDM_{yrRfms} \cdot OPDM_{yrRfms} \\
&+ \sum_y \sum_r \sum_n COPR_{yrn} \cdot OPR_{yrn} + \sum_y \sum_r \sum_R COPB_{yrR} \cdot OPB_{yrR} \\
&+ \sum_y \sum_r \sum_l COPH_{yrl} \cdot OPH_{yrl} + \sum_y \sum_r \sum_R \sum_c \sum_E CBLD_{yrRcE} \cdot BLD_{yrRcE} \\
&+ \sum_y \sum_r \sum_l \sum_E CINT_{yrlE} \cdot INT_{yrlE} + \sum_y \sum_r \sum_E CDST_{yrE} \cdot DST_{yrE} \\
&+ \sum_y \sum_r \sum_n \sum_E CRNW_{yrnE} \cdot RNW_{yrnE} + \sum_y \sum_h \sum_p CBCH_{yhp} \cdot BCH_{yhp} + \sum_y \sum_e \sum_g CBLX_{yeg} \cdot BLX_{yeg} \\
&+ \sum_y \sum_r \sum_t \sum_q (CDGN_{yrt} - CAVD_{yrq}) \cdot DGN_{yrqt} + \sum_y \sum_N \sum_A CBCF_{yA} \cdot BCF_{yNA} \\
&+ \sum_y \sum_O \sum_H \sum_I CRET_{yOHI} \cdot UNIT_{yOH} + \sum_y \sum_O \sum_H CHRI_{yO} \cdot HRI_{yOH} + \sum_y \sum_O \sum_I CHRI_{yO} \cdot HRI_{yOI} \\
&+ \sum_y \sum_O CCGC_{yO} \cdot CGC_{yO} + \sum_y \sum_O CCGC_{yO} \cdot CGCL_{yO} + \sum_y \sum_V CRCC_{yV} \cdot RCC_{yV} \\
&+ \boldsymbol{\sum_y \sum_e \sum_g \sum_s \sum_l} CTRE_{yegsl} \cdot TRE_{yegsl} + \boldsymbol{\sum_y} CCAR_y \cdot \boldsymbol{CARE_y}
\end{aligned}
$$

Description of constraints

Coal Submatrix. ECP contains a series of equations to represent the production, transportation, and consumption of coal by electric generators. These constraints simulate the costs and characteristics of the different coals described by supply curves in CMM. ECP determines decisions for operation, capacity expansion, and emissions control in coal-fired capacity based on this representation. Because coal-fired plants can also be modified to cofire with biomass fuels, decisions to retrofit existing capacity to allow cofiring are also included in this structure.

ECP uses the same two-tier pricing system for transportation costs that is incorporated in CMM. This methodology assumes that the amount of coal that can be delivered at current rates is limited to historical flows. Additional quantities are assumed to require an incremental cost.

Each of the supply curves represents coal from a single coal supply region, characterized by one rank (bituminous, subbituminous, or lignite), emissions content (average), and cost structure. This document also uses the term supply curve to refer to the collection of producers represented on a supply curve. Coal supply curves are for domestic and international supply regions. A coal supply region may contain more than one supply curve, and the coal produced in a given coal supply region may be able to be transported for use by generators in multiple coal demand regions serving the electricity regions. Similarly, coal-fired plants in a particular electricity region may be able to obtain fuel supplies from more than one coal demand region.

Coal Production balance rows. These rows ensure that the coal production from each of the coal supply curves does not exceed the available annual capacity of the mines. For each supply curve *J*, the following constraints specify that the total annual production of coal over all of the supply steps M (PCL_{yJM}) does not exceed the maximum production level (MAX_{yJ}):

(3-2)
$$\sum_{M} PCL_{yJM} \leq MAX_{yJ}$$

for every coal supply curve J in year y.

Material balance rows for coal supply. These equations balance the coal produced by a particular supply curve (PCL_{yJM}) and the coal transported to generating plants (TCL_{yJNCa}). Production must also be sufficient to satisfy nonutility coal use (OTH_{yJ}). The rows are specified as follows:

(3-3)
$$\sum_{N}\sum_{C}\sum_{a} TCL_{yJNCa} + OTH_{yJ} - \sum_{M} PCL_{yJM} \leq 0$$

for every coal supply curve J in year y.

Material balance rows for coal demand. These constraints ensure that the coal transported from the coal supply regions is sufficient to satisfy the fuel consumption of unscrubbed and scrubbed generating plants (including must-run) in fuel demand regions, which correspond to a particular coal region N. For each coal capacity type C, the fuel requirement is the product of the capacity allocated to produce

electricity (OPC$_{yrRCms}$) and the fuel use per unit of capacity (CBTUC$_{yrCms}$). Similarly, fuel use by must-run plants is the product of the corresponding operate variable (OPC$_{yrRCms}$) and fuel use rate (CBTUC$_{yrCms}$). Coal use is also reduced by biomass fuel used for cofiring (TBM$_{yrNABC}$). The material balance rows ensure that the coal transported (TCL$_{yJNCa}$) is sufficient to satisfy the demand by each coal-fired capacity type in the fuel regions R that represent a given coal region N, as follows:

$$(3\text{-}4) \quad \sum_r \sum_{R=N} \sum_m \sum_s \mathbf{CBTUC}_{yrCms} \cdot \mathbf{OPC}_{yrRCms} + \sum_r \sum_{R=N} \sum_m \sum_s \mathbf{CBTUC}_{yrCms} \cdot \mathbf{OPCM}_{yrRCms} +$$
$$- \sum_J \sum_a \mathbf{TCL}_{yJNCa} - \sum_r \sum_{A} \sum_{B} \mathbf{TBM}_{yrNABC} \leq \mathbf{0}$$

for every coal-fired plant type C in coal region N in year y.

Coal Contract flows. These equations require minimum quantities of coal production to satisfy electricity contracts for coal produced by specific coal curves and transported to specific electricity generators. For coal used in unscrubbed plant types F, the contract flows are represented as follows:

$$(3\text{-}5) \quad \sum_F \sum_a \mathbf{TCL}_{yJNFa} \geq \mathbf{CUNS}_{yJN}$$

for every unscrubbed supply curve J to coal region N in year y.

The analogous constraints for contract flows to scrubbed plants are obtained by substituting the scrubbed capacity types G for the unscrubbed capacity types F.

Coal Diversity requirements. Some coal-fired generator units are not able to burn subbituminous coal or lignite or can only use limited amounts. These equations impose limits on the quantity of subbituminous and lignite coal that can be used to satisfy coal demands by specified ECP coal capacity types F and regions. For subbituminous coal in units O of configuration H that correspond to unscrubbed capacity type F, the diversity constraints are represented as follows:

$$(3\text{-}6) \quad \sum_K \sum_a \mathbf{TCL}_{yKNFa} - \sum_O \sum_H \mathbf{CDVS}_{yOH} \bullet \mathbf{UNIT}_{yOH} \leq \mathbf{0}$$

for unscrubbed capacity type F in coal region N in year y.

The coefficient CDVS$_{yOH}$ represents the maximum quantity, per GW of capacity, of the total coal consumed by coal-fired generator units O of unscrubbed configuration H that can be satisfied by subbituminous coal in year *y*.[15] The product of this coefficient and the capacity variable UNIT$_{yOH}$ provides the corresponding contract flows. Thus, the equation states that the sum of subbituminous coal transported from the subbituminous supply curves K to unscrubbed coal-fired plants H in coal region N

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[15] CDVS$_{yOH}$ is derived by multiplying the total fuel consumed at the unit during the previous year by the maximum share of this demand that can be satisfied by subbituminous coal and then dividing by the total capacity. The subsequent coefficients for lignite and scrubbed capacity types are determined similarly.

cannot exceed the maximum allowable use of subbituminous coal. Similar constraints are also imposed for subbituminous coal consumption in scrubbed plants by substituting the scrubbed capacity types G for the unscrubbed capacity types H and the scrubbed configurations J for the unscrubbed configurations I. The analogous constraints for lignite use in both unscrubbed and scrubbed capacity are obtained by replacing the subbituminous supply curves K with the lignite supply curves L.

Coal Transportation rates. Transportation rates are applied using a two-tier system. The first tier rates assume that the current rates are limited to historical flow levels. To deliver additional supplies, an incremental cost (second-tier rates) is incurred. The constraints on first-tier rates are imposed as follows:

(3-7)
$$\sum_{a} \mathbf{TCL}_{yJNFa} - \mathbf{TC2}_{yJNF} - \sum_{O} \sum_{H} \mathbf{CBT1}_{yJOH} \cdot \mathbf{UNIT}_{yOH} \leq 0$$

for every supply curve J to unscrubbed capacity type F in coal region N in year y.

The coefficient $CBT1_{yJOH}$ represents the maximum quantity, per GW of capacity, of the total coal consumed by coal-fired generator unit O of unscrubbed capacity configuration H that can be transported from supply curve J at the first-tier rates.[16] The product of this coefficient and the capacity variable $UNIT_{yOH}$ provides the corresponding quantities with these rates. Thus, the equation states that the total transportation of coal from supply curve J to unscrubbed plants in coal region N in year y is the sum of the first-tier and second-tier flows. The analogous constraints for tier flows to scrubbed plants are obtained by substituting the scrubbed capacity types I for the unscrubbed capacity types H and the units O with scrubbed configurations K instead of unscrubbed configurations J.

Natural Gas Submatrix. Like the fuel curves described in the coal submatrix, these equations describe the consumption, transportation, and supply of natural gas for electricity generation. Delivered natural gas prices vary not only by quantity but also by location and timing. Thus, natural gas use is accumulated for each fuel region R and fuel season S.

Material balance rows for gas demand. These constraints accumulate the fuel consumption required to generate electricity by non-coal, fossil fuel capacity D using fuel f (natural gas) in fuel region R in fuel season S in year y (TFL_{yQDSf}). These plants may be dual-fired capacity using both oil and natural gas. The corresponding electricity generation for each mode of operation m and load segment l is the product of the capacity assigned to the mode of operation (OPD_{yrRDms}) and the fuel use per unit of capacity ($CBTUD_{yrDms}$). Therefore, Equation (3-8) describes fuel consumption in non-coal fossil fuel plants for non-must-run capacity, as follows:

(3-8)
$$\sum_{r} \sum_{m} \sum_{S} \mathbf{CBTUD}_{yrDmS} \bullet \mathbf{OPD}_{yrRDmS} - \sum_{f} \mathbf{TFL}_{yRDSf} \leq 0$$

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[16] $CBT1_{yJOH}$ is derived by multiplying the total fuel consumed at the unit O of unscrubbed configuration H during the previous year by the allowable share from supply curve J that is subject to tier-one rates and then dividing by the total capacity. The subsequent coefficients for scrubbed capacity types are determined similarly.

for every natural gas-fired capacity type D in fuel region R and natural gas season S in year y.

Similarly, natural gas consumption for must-run capacity is determined as follows:

(3-9)

$$\sum_{r}\sum_{m}\sum_{S} \mathbf{CBTUD}_{yrDmS} \bullet \mathbf{OPDM}_{yrRDmS} - \sum_{f} \mathbf{TFLM}_{yRDSf} \leq 0$$

for every natural gas-fired capacity type D in fuel region R and fuel season S in year y.

Material balance rows for natural gas transportation. These constraints ensure that sufficient quantities of natural gas are delivered to each fuel region R in both the peak and off-peak periods S. The delivered fuel requirement (TNG$_{yRST}$) is the sum of the non-must-run and must-run capacity. Because some of the capacity types D may be dual-fired, the corresponding natural gas use may represent a share (SNG$_{yQDf}$ and SNGM$_{yQDf}$) of the fuel type f. Regional peak and off-peak natural gas consumption is then accumulated by the following equation:

(3-10)

$$\sum_{D}\sum_{f} SNG_{yRDf} \cdot TFL_{yRDfS} + \sum_{D}\sum_{f} SNGM_{yRDf} \cdot TFLM_{yRDfS} - \sum_{T} TNG_{yRST} \leq 0$$

for fuel region R and fuel season S in year y.

Material balance rows for natural gas supply. These constraints balance the production of natural gas and the transportation requirements for natural gas-fired generation. These rows are specified as follows:

(3-11)

$$\sum_{R}\sum_{S}\sum_{T} \mathbf{TNG}_{yRST} - \sum_{d} \mathbf{QNG}_{yd} \leq 0$$

for every year y.

Material balance rows for hydrogen gas supply curve. These constraints ensure that the total consumption of hydrogen gas from all corresponding fuel regions R, hydrogen plant types D for gas season S in year y would not exceed the max hydrogen gas available from all hydrogen supply steps available to census division X. These rows are specified as follows:

(3-12)

$$\sum_{R}\sum_{D} SNH2_{yRDf|f=H2} \cdot TFL_{yRDfS} - \sum_{d} QH2_{yXSd} \leq 0$$

Oil Submatrix. These equations represent the consumption, transportation, and supply of oil for both single-fired and dual-fired plants. They are very similar to the corresponding constraints for natural gas described above. However, oil supplies are not characterized by different seasons so there is only one fuel season S.

Material balance rows for oil demand. These constraints determine the total fuel requirements for plants using oil. For oil fuel types f, the respective consumption totals for non-must-run and must-run capacity are specified as follows:

(3-13)
$$\sum_r \sum_m \sum_S \mathbf{CBTUD}_{yrDmS} \bullet \mathbf{OPD}_{yrRDmS} - \sum_f \mathbf{TFL}_{yRDSf} \leq \mathbf{0}$$

for every oil-fired capacity type D in fuel region R and fuel season S in year y.

Similarly, oil consumption for must-run capacity is determined as follows:

(3-14)
$$\sum_r \sum_m \sum_S \mathbf{CBTUD}_{yrDmS} \bullet \mathbf{OPDM}_{yrRDmS} - \sum_f \mathbf{TFLM}_{yRDSf} \leq \mathbf{0}$$

for every oil-fired capacity type D in fuel region R and fuel season S in year y.

Material balance rows for oil transportation. These constraints ensure that sufficient quantities of oil (TOL_{yRT}) are delivered to each fuel region R in both the peak and off-peak periods S. The delivered fuel requirement (TOL_{yRT}) is the sum of the non-must-run and must-run capacity. Because some of the capacity types D may be dual-fired, the corresponding oil use may represent a share (SOL_{yQDf} and $SOLM_{yQDf}$) of the oil fuel type f. Regional peak and off-peak natural gas consumption is then accumulated by the following equation:

(3-15)
$$\sum_D \sum_f \mathbf{SOL}_{yRDf} \bullet \sum_S \mathbf{TFL}_{yRDfS} + \sum_D \sum_f \mathbf{SOLM}_{yRDf} \bullet \sum_S \mathbf{TFLM}_{yRDfS} - \sum_T \mathbf{TOL}_{yRT} \leq \mathbf{0}$$

for fuel region R and year y.

Material balance rows for oil supply. These constraints ensure that sufficient oil supplies are produced to satisfy the transportation requirements for oil used in electricity generation. These rows are specified as follows:

(3-16)
$$\sum_R \sum_T \mathbf{TOL}_{yRT} - \sum_d \mathbf{QOL}_{yd} \leq \mathbf{0}$$

for every year y.

Biomass Submatrix. These equations represent the consumption, transportation, and supply of biomass fuels for electricity generation in each biomass region N, which may serve multiple fuel regions R and EMM regions r. They represent regional fuel curves for biomass consumed in dedicated biomass plants and cofiring in coal-fired steam plants. Fuel use in dedicated biomass capacity type is the product of the capacity allocated (OPB_{yrR}) and the fuel use per unit of capacity ($CBTUB_{yr}$). Biomass fuel used for cofiring in coal capacity types C is described by the decision variable TBM_{yrRABC}. Equation (3-16) describes total biomass fuel use for electricity generation ($TBMUT_{yNW}$) using a series of decision variables (QBM_{yNd}). Note that a fuel region R contains a single coal region N, but multiple fuel regions can map to the same coal region. Therefore, some variables in the following equation are summed over the fuel regions R that have the same coal region N.

(3-17)
$$\sum_r \sum_R \mathbf{CBTB}_{yr} \bullet \mathbf{OPB}_{yrR} + \sum_r \sum_R \sum_A \sum_B \sum_C \mathbf{TBM}_{yrRABC} - \sum_W \mathbf{TBMUT}_{yNW} \leq 0$$

for every biomass region N in year y.

Total biomass requirements include fuel consumed in the industrial sector ($TBMIN_{yNW}$), ethanol production ($QBMET_{yNW}$), hydrogen production ($QBMHY_{yNW}$), and biomass to liquids ($QBMBT_{yNW}$). The end-use demand models determine these demands, and they represent competing demands for the available biomass supplies. Equation (3-18) insures that sufficient biomass fuel is produced to meet the corresponding demands for all sectors, as follows:

(3-18)
$$\mathbf{TBMUT}_{yNW} + \mathbf{TBMIN}_{yNW} + \mathbf{TBMET}_{yNW} + \mathbf{TBMHY}_{yNW} + \mathbf{TBMBT}_{yNW} - \sum_d \mathbf{QBM}_{yNWd} \leq 0$$

for every biomass fuel W in coal region N in year y.

Biomass cofiring capacity balance rows. Coal-fired plants can be retrofitted to cofire coal with biomass fuel. The maximum cofiring shares depend on the type of boiler and the size of the coal-fired generator unit so the available capacity is divided into retrofit categories A to represent the corresponding variations in cofiring capability.[17] For each cofiring category, additional cofiring levels B can be achieved by incurring additional transportation costs for incremental biomass supplies.

These equations ensure that the use of biomass in coal-fired capacity does not exceed the capability that has been retrofitted to allow cofiring at specified levels. The available cofiring capacity is the sum of the previous retrofit decisions by cofiring category A (ECF_{yrNA}) and new retrofit decisions (BCF_{yrNA}). The transportation of biomass for cofiring in coal capacity type C in coal region N (TBM_{yrNABC}) is converted to the equivalent generating capacity by dividing by the product of the corresponding cofiring level

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[17] The assumptions for costs and production levels associated with retrofitting coal-fired units to cofire with biomass were developed in a series of communications between EIA staff and analysts from the Electric Power Research Institute (EPRI) and the Antares Group, Incorporated.

(CFLEV$_{AB}$) and the fuel use per unit of capacity (CFBTU$_{yNA}$).[18] Therefore, Equation (3-19) ensures that coal-fired capacity using biomass does not exceed the existing and new retrofitted capacity, as follows:

(3-19)
$$\sum_{B}\sum_{C} \mathbf{TBM_{yrNABC}}/(\mathbf{CFBTU_{yNA}} \cdot \mathbf{CFLEV_{AB}}) - \mathbf{ECF_{yrNA}} - \mathbf{BCF_{yrNA}} \leq \mathbf{0}$$

for each cofiring category A in coal region N and EMM region r in year y.

Biomass cofiring production balance rows. This set of constraints ensures that the production (and fuel consumption) from biomass in coal-fired capacity does not exceed the maximum cofiring levels corresponding to the retrofit decisions (CFLEV$_{AB}$). For each coal-fired capacity type C in EMM region r and coal region N in year y, TBM$_{yrNABC}$ describes the consumption of biomass fuels for use in coal-fired plants, and TCL$_{yJNCa}$ represents the corresponding transportation of coal. The coefficient of TBM$_{yrNABC}$ is the ratio of the coal share to the biomass share. Therefore, Equation (3-20) limits fuel use of biomass relative to coal according to the retrofitted cofiring levels, as follows:

(3-20)
$$\sum_{r}\sum_{A}\sum_{B} \mathbf{TBM_{yrNABC}} \bullet (\mathbf{1} - \mathbf{CFLEV_{AB}})/\mathbf{CFLEV_{AB}} - \sum_{J}\sum_{a} \mathbf{TCL}_{yJNCa} \leq \mathbf{0}$$

for each coal capacity type C and coal region N in year y.

Emissions. These constraints limit the emissions produced from electricity generation. The equations below are described for SO_2, NO_x, CO_2, and Hg emissions, which are restricted by current regulations. ECP can accommodate multiple emissions restrictions simultaneously by incorporating each set of constraints within the model.

The CSAPR specifies emissions targets for 27 states and includes variability limits that allow states to exceed their targets by a specified amount by trading allowances with other states. EMM does not operate at an individual state level, so these standards are represented for the coal regions, which consist of both individual and combinations of states. For those coal regions containing multiple states, both the targets and variability limits are summed for the corresponding states.

Potentially, each capacity type may produce emissions although coal-fired plants produce most of the emissions. The amount of emissions produced depends on the type and amount of fuel used and the pollution control devices installed (if any). For coal capacity, the decision variable TCL$_{yJNCa}$ describes the coal transported for use in power plants, and SO2C$_{yJNC}$ represents the corresponding emission rate for SO_2.[19] The product of these two terms gives the SO_2 emissions from coal.

SO_2 emissions from natural gas and distillate fuel oil are negligible, so the only non-coal SO_2 emissions produced by oil steam plants are from residual fuel oil. These emissions are the product of the consumption of residual fuel oil (TOL$_{yRT}$) and the emissions rate (SO2D$_{yRf}$) over the fuel regions R corresponding to coal region N.

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[18] The fuel use per unit of capacity depends on the utilization rate. We use the utilization rate from the previous year to determine this value.

[19] The emissions coefficient accounts for controls, if applicable. The use of activated carbon only affects Hg emissions, so it is not reflected in the SO_2 coefficient.

Therefore, the CSAPR limits for SO$_2$ emissions (LSO2$_{yN}$), accounting for allowances traded from coal region N (SO2T$_{yNo}$) and to coal region N (SO2T$_{yoN}$) are expressed as follows:

$$(3\text{-}21) \quad \sum_J \sum_C \sum_a \mathbf{SO2C_{yJNC}} \bullet \mathbf{TCL_{yJNCa}} + \sum_T \sum_{R \in o} \mathbf{SO2D_{yRf}} \bullet \mathbf{TOL_{yRT}} + \sum_{o \neq N} \mathbf{SO2T_{yNo}} - \sum_{o \neq N} \mathbf{SO2T_{yoN}} \leq \mathbf{LSO2_{yN}}$$

for every CSAPR (coal) region N in year y.

The variability limits on allowance trading are defined as follows:

$$(3\text{-}22) \quad \sum_{o \neq N} \mathbf{SO2T_{yoN}} \leq \mathbf{LSO2V_{yN}}$$

for every CSAPR (coal) region N in year y.

Limitations on NO$_X$ emissions are implemented for specific groups of states in the CSAPR. As with SO$_2$ and Hg, coal-fired capacity accounts for virtually all of the NOx emissions resulting from power generation. Because the NOx content does not really vary between different types of coal, the corresponding emissions cannot be reduced by switching coals, and the available compliance options only involve installing pollution control equipment.

The product of the NOx emission rate per unit of capacity (NOXC$_{NCms}$) and the utilization variables (OPC$_{yvNCms}$ and OPCM$_{yvNCms}$) describes the emissions from coal-fired plants in NOx CSAPR region v (TNOX$_{yvC}$). For non-coal-fired plants, multiplying the corresponding emission rate (NOXD$_{Dfms}$) and the utilization variables (OPD$_{yrDfms}$ and OPDM$_{yvDfms}$) totals these emissions (TNOX$_{yvD}$). Equations (3-23) and (3-24) identify the total NOx from coal-fired plant type C (NOXE$_{yvC}$) and non-coal-fired plant type D (NOXE$_{yvD}$), respectively:

$$(3\text{-}23) \quad \sum_N \sum_m \sum_s \mathbf{NOXC_{NCms}} \bullet (\mathbf{OPC_{yvNCms}} + \mathbf{OPCM_{yvNCms}}) - \mathbf{NOXE_{yvC}} \leq \mathbf{0}$$

for each coal capacity type C in NO$_X$ CSAPR region v in year y, and:

$$(3\text{-}24) \quad \sum_f \sum_m \sum_s \mathbf{NOXD_{Dfms}} \bullet (\mathbf{OPD_{yrDfms}} + \mathbf{OPDM_{yrDfms}}) - \mathbf{NOXE_{yvD}} \leq \mathbf{0}$$

for each non-coal capacity type D in NO$_X$ CSAPR region v in year y.

The last term on the left-hand side of the equation (3-25) accounts for the reduction in emissions that results from converting a coal-fired generator unit from an uncontrolled configuration H to a controlled

configuration I. The reductions in NO_X emissions that result from retrofitting uncontrolled coal-fired generator units with pollution control devices (NOXX$_{yvC}$) are represented as follows:

$$\mathbf{NOXX}_{\mathbf{yvC}} - \sum_{\mathbf{O}}\sum_{\mathbf{H}}\sum_{\mathbf{I}}\mathbf{NOXR}_{\mathbf{yOHI}} \bullet \mathbf{UNIT}_{\mathbf{yOH}} \leq \mathbf{0}$$

(3-25)

for each coal capacity type C in NOx CSAPR region v in year y.

The NO$_X$ emissions limit (LNOX$_{yv}$) is imposed by summing up the emissions for all the plant types and subtracting the reductions from retrofits, as described in Equation (3-26).

(3-26)
$$\sum_{\mathbf{C}}\mathbf{NOXE}_{\mathbf{yvC}} + \sum_{\mathbf{D}}\mathbf{NOXE}_{\mathbf{yvD}} - \sum_{\mathbf{C}}\mathbf{NOXX}_{\mathbf{yvC}} \leq \mathbf{LNOX}_{\mathbf{yv}}$$

for each NO$_X$ CSAPR region v in year y.

The MATS require that the MACT be implemented to control HAPs, including acid gases and Hg. Compliance with the acid gas standards is assumed to be achieved through the use of either FGD scrubbers or the combination of DSI equipment and full fabric filters. The Hg MACT may also require the use of activated carbon to achieve the specified removal rate. Therefore, coal capacity is limited to configurations (combinations of pollution control equipment) and coal types (TRC$_{yJRCa}$) that can achieve the specified rates using activated carbon, if necessary. A coal-fired plant that cannot meet the standard with its current configuration would have to install additional control devices to continue operating.

The generic formulation of a cap on carbon emissions is similar to quantity-based programs for SO$_2$, NO$_X$, and Hg. Carbon emissions from fossil fuels are the product of fuel consumption and the corresponding emissions rates. The carbon emissions for a coal-fired plant depend on the carbon content of the coal (CARC$_{yJR}$), the carbon removal rate (CARR$_C$) if the plant has coal capture and sequestration (CCS) technology, and the quantity of coal (TRC$_{yJRCa}$). Similarly, the resulting emissions from natural gas and oil are the product of the corresponding carbon content, carbon removal rate (if any), and fuel use. Unlike coal, the carbon contents for natural gas and oil do not vary geographically, so each fuel is characterized by a single rate. Also, generation from renewable (geothermal and municipal solid waste) plants (CARR$_y$) produce some carbon emissions. Equation (3-27) accumulates total annual electric power carbon emissions (CARE$_y$), as follows:

$$\sum_{\mathbf{J}}\sum_{\mathbf{R}}\sum_{\mathbf{C}}\sum_{\mathbf{a}}\mathbf{CARC}_{\mathbf{yJR}} \bullet (1 - \mathbf{CARR}_{\mathbf{C}}) \bullet \mathbf{TRC}_{\mathbf{yJRCa}} +$$

(3-27)

$$\sum_{\mathbf{R}}\sum_{\mathbf{D}}\sum_{\mathbf{f}}\sum_{\mathbf{S}}\mathbf{CARD}_{\mathbf{yf}} \bullet (1 - \mathbf{CARR}_{\mathbf{D}}) \bullet \mathbf{TFL}_{\mathbf{yRDfS}} + \mathbf{CARO}_{\mathbf{y}} - \mathbf{CARE}_{\mathbf{y}} \leq \mathbf{0}$$

in year y.

The objective function coefficient of the variable for total carbon emissions is the carbon price (CCAR$_y$), so the cost of using carbon-producing generators is increased by the cost of purchasing allowances.

Some states have combined to enact or consider regional caps on greenhouse gas emissions. In particular, a group of 11 northeastern and mid-Atlantic states have formed the RGGI, which is an agreement to limit future carbon emissions.[20] Regional power sector carbon limits for RGGI or other containment areas Q in year y (LCAR$_{yQ}$) are specified in Equation (3-28). If compliance becomes too costly, offsets (Off$_y$), cost containment reserve allowances (RSV$_y$), and emission containment reserve allowances (ECR$_y$) can be used instead of a corresponding reduction in emissions:

(3-28)

$$\sum_J \sum_{R \in Q} \sum_C \sum_a CARC_{yJR} \cdot (1 - CARR_C) \cdot TRC_{yJRCa} +$$
$$\sum_{R \in Q} \sum_D \sum_f \sum_S CARD_{yf} \cdot (1 - CARR_D) \cdot TFL_{yRDfS} -$$
$$OFF_y - RSV_y - ECR_y \leq LCAR_{yQ}$$

for every containment area Q in year y.

Another carbon containment area was defined because of California's AB398. The corresponding limit on carbon emissions is similar to Equation (3-28), but the left-hand side of the equation includes two additional terms to account for emissions associated with electricity imports and plants owned by California suppliers but located outside the state. For the EMM region r that corresponds to the California containment area Q, Equation (3-29) describes the carbon emissions from imports (CIM$_{yQ}$):

(3-29)
$$\mathbf{CIM}_{yQ} = \sum_e \sum_s \sum_l \mathbf{TRE}_{yersl} \bullet \mathbf{LHRS}_l \bullet \mathbf{CARI}_{eQ}$$

Similarly, Equation (3-30) represents the corresponding emissions from coal-fired generator units owned by California suppliers but located in another fuel region R:

(3-30)
$$\mathbf{COS}_{yQ} = \sum_{R \notin r} \sum_C \sum_m \sum_s \mathbf{CBTUC}_{yrRCms} \bullet \mathbf{OPC}_{yrRCms} \bullet \mathbf{CARP}_{yCR}$$

In addition to the electric power industry, AB398 covers other major sources of greenhouse gas emissions. Therefore, the limit for California includes these carbon emissions, including industry (CARIN$_y$), refineries (CARRF$_y$), fuel providers (CARRF$_y$), and other (CAROT$_y$). Allowances may be traded among sectors, but the combined emissions are subject to the total allowances allocated. However, the

---

[20] RGGI specifies restrictions for carbon dioxide, which are then converted to carbon for ECP.

limit in a particular year can be exceeded by using banked allowances ($BNKC_y$) and reserve allowances ($RSVC_y$) accumulated in previous years and by using offsets ($OFFC_y$). The combined sector constraint incorporates these additional factors as follows:

$$
\begin{aligned}
(3\text{-}31) \quad & \sum_J \sum_{R \in Q} \sum_C \sum_a \mathbf{CARC_{yJR}} \bullet (1 - \mathbf{CARR_C}) \bullet \mathbf{TRC_{yJRCa}} + \\
& \sum_{R \in Q} \sum_D \sum_f \sum_S \mathbf{CARD_{yf}} \bullet (1 - \mathbf{CARR_D}) \bullet \mathbf{TFL_{yRDfS}} + \\
& \sum_{R \notin r} \sum_C \sum_m \sum_s \mathbf{CBTUC_{yrRCms}} \bullet \mathbf{OPC_{yrRCms}} \bullet \mathbf{CARP_{yCR}} + \\
& \sum_e \sum_s \sum_l \mathbf{TRE_{yersl}} \bullet \mathbf{LHRS_l} \bullet \mathbf{CARI_{eQ}} + \mathbf{CIM_{yQ}} + \mathbf{COS_{yQ}} + \\
& \mathbf{CARIN_y} + \mathbf{CARRF_y} + \mathbf{CARFL_y} + \mathbf{CAROT_y} \\
& - \mathbf{BNK_y} - \mathbf{RSV_y} - \mathbf{OFF_y} \leq \mathbf{LCAR_{yQ}}
\end{aligned}
$$

for California AB398 containment area Q in year y.

Representation of Power Plant Captured CO_2. The Carbon Capture, Allocation, Transportation, and Sequestration (CCATS) module in NEMS represents the market for CO_2. It is an optimization model that minimizes the costs of transporting and sequestering or utilizing CO_2 and determines the most cost-effective network flow of CO_2 from supply sources to demand locations, including both EOR sites and saline storage. CCATS passes EMM a net CO_2 cost ($CNTX_{Xy}$) by Census division and EMM determines the amount of CO_2 that is captured by different sources.

By convention, biomass combustion is assumed to result in net-zero CO_2 emissions. However, for the biomass energy with carbon capture (BECC) technology, the emissions released during combustion are captured, and an emission rate (CO2B) must be assumed to be able to calculate the amount of CO_2 captured, and this technology will end up with a negative contribution to overall emissions.

CO_2 that is captured from power plants in each fuel region R that is part of Census Division X must either be sent to EOR or saline injection, so this is modeled as an equality constraint, so the cost of every ton captured is included in the objective function:

(3-32)

$$
\begin{aligned}
& \sum_{R \in X} \sum_r \sum_C \sum_s \sum_m \mathbf{CARR_C} \cdot \mathbf{CARC_{yR}} \cdot \mathbf{CBTUC}_{yrCms} \cdot \mathbf{OPC_{yrRCms}} + \\
& \sum_{R \in X} \sum_r \sum_D \sum_s \sum_m \mathbf{CARR_C} \cdot \mathbf{CARD_{yf}} \cdot \mathbf{CBTUD}_{yrms} \cdot \mathbf{OPD_{yrRDms}} + \\
& \sum_{R \in X} \sum_r \mathbf{CARR_C} \cdot \mathbf{CARB_y} \cdot \mathbf{CBTUB}_{yr} \cdot \mathbf{OPB_{yrR}} \; - \; \mathbf{NTX_{Xy}} \; = \; 0
\end{aligned}
$$

for every Census division X and year y.

National short-term supply cost adjustments. ECP includes short-term supply cost adjustment factors for the installation of new electricity generating technologies. The factors reflect the expectation that rapid expansions in the supply of installations using new generating technologies will incur shortages of critical input resources. Shortages could reflect manufacturing bottlenecks, as well as delays in regulation, licensing and public approval, and constraints incurred from shortages of construction and operations personnel and equipment.

In ECP, U.S. generating capacities of new technologies are permitted to increase by a prespecified amount without including cost increases, but above some threshold rate of increase, costs are assumed to increase. Capacity builds in a given year can be up to 25% above a base amount ($CPBAS_{yc}$) without a cost adjustment. The base amount is equal to the greatest amount of capacity brought online in a single year during the past five years, for each technology, weighted by a time factor so that earlier builds are discounted. If no existing capacity is online, then an offline assumption is used for the base amount, which is set based on the newness of the technology.

The short-term cost adjustment factors are based on the percentage change of national installed capacity of a technology, using an exponential cost function relating an increase in capacity to a cost multiplier. The function is divided into three distinct points to establish a three-step supply curve for the installation of new capacity. The capacity assumed for the steps ($CPSTP_{cE}$) is 125% of the base amount for the first step, 75% of the base amount for the second step, and 100% of the base amount for the third step. The first step has a cost multiplier of 1.0, which implies no increase in costs. The cost multipliers for the second and third steps are calculated from the following function:

(3-33)
$$CST_{yCE} = \left(\frac{C_2}{C_1} - a_{thresh}\right)^{\frac{\ln(1+a_2)}{\ln(1+a_1)}}$$

where

CST_{yCE}	=	cost multiplier for year y, capacity type c, and short-term supply step E;
C_1	=	capacity at current step;
C_2	=	capacity at midpoint of subsequent step; and
a_{thresh}	=	threshold above which elasticity is active, defined as percentage increase based on current installed capacity (currently 25%);
a_1	=	increase in capital cost for every a_2 increase in capacity, fraction; and
a_2	=	increase in capacity, fraction.

The midpoint of the step is used to linearly approximate the log linear supply equation. The cost multiplier represents the average cost increase over the full range of the capacity step, rather than a

direct response for each increment of new capacity. The number of steps was chosen to limit the number of new decision variables in the ECP while still accurately portraying the relationship between rapid capacity increases and cost increases. The user specifies the capacity limit for each step, and when these values change, the cost multipliers will respond accordingly. For example, by making the second step larger, allowing for more capacity additions, the cost multiplier will go up.

The short-term expansion constraint for dispatchable technologies is as follows:

$$(3\text{-}34) \quad \sum_r \mathbf{BLD_{yrCE}} + \sum_r \sum_e \mathbf{BDI_{yecrE}} \leq \mathbf{CPLIM}_{\mathbf{yrCE}}$$

for every capacity type c, year y, and supply step E.

where

$$\mathbf{CPLIM_{ycE}} \quad = \quad \mathbf{CPSTP_{cE}} * \mathbf{CPBAS_{yc}}$$

Analogous constraints exist for intermittent and renewable builds. The objective function coefficients for the appropriate build vectors (CBLD$_{yrRcE}$, CRNW$_{yrnE}$, CINT$_{yriE}$,) represent the overnight cost multiplied by the cost multiplier for each supply step, as calculated in (3-33).

Must-run constraints. These equations specify the minimum generation requirement (MRUN$_{yrc}$) based on historical utilization rates for must-run capacity from certain plants that are relatively uneconomical. Production from these plants is given by the product of capacity utilization rate (ELA$_{yrcmsl}$), the hours (in thousands) in each load segment (LHRS$_l$), and the operate decision variable (OPM$_{yrRcms}$). Therefore, the must-run constraints are given by:

$$(3\text{-}35) \quad \sum_s \sum_m \sum_l ELA_{yrCmsl} \bullet LHRS_l \bullet OPM_{yrRcms} \geq MRUN_{yrC}$$

for every capacity type c in fuel region R and EMM region r in year y.

Planned maintenance constraints. The planned maintenance constraints ensure that the total of the seasonal planned maintenance scheduled for each dispatchable technology satisfies the annual maintenance requirements for that technology. For coal-fired capacity, these constraints are defined as follows:

$$(3\text{-}36) \quad \sum_s \mathbf{SHOURS_s} \bullet \mathbf{PMC_{ysCrR}} - 8.76 \bullet \mathbf{CPMR_{rC}} \bullet \sum_O \sum_H \mathbf{UNIT}_{\mathbf{yOH}} - 8.76 \bullet \mathbf{CPMR}_{\mathbf{rC}} \bullet \sum_O \sum_I \mathbf{UNIT}_{\mathbf{yOI}}$$

$$- 8.76 \bullet \sum_{j=1}^{y} \sum_E \mathbf{CPMR_{rC}} \bullet \mathbf{BLD_{jrRCE}} \geq 0$$

for every coal capacity type C in year y in fuel region R and EMM region r.

In the first term, SHOURS$_s$ represents the number of hours in season s (in thousands of hours), and PMC$_{ysCrR}$ is the decision variable that determines the amount of capacity undergoing planned

maintenance in that season. The product of these two quantities summed over the season specifies the total number of hours each coal capacity type is undergoing maintenance in each region and year. A year has 8.76 thousands of hours, so the terms $8.76 \bullet \text{CPMR}_{rC} \bullet \text{UNIT}_{yOH}$ and $8.76 \bullet \text{CPMR}_{rC} \bullet \text{UNIT}_{yOI}$ define the annual maintenance requirements for uncontrolled and controlled coal-fired generator units, respectively. Only the units UNIT_{yOH} and UNIT_{yOI} that are located in EMM region r and fuel region R are included. Similarly, the term $8.76 \bullet \text{CPMR}_{rC} \bullet \text{BLD}_{jrRCE}$ describes maintenance for new capacity. Therefore, planned maintenance rows require that the total allocation of capacity type C for planned maintenance over all seasons equals or exceeds the annual requirements for that capacity type.

A separate, but similar, set of rows are defined to represent planned maintenance for existing must-run coal capacity. These equations are derived by substituting the planned maintenance decision variables for must-run units (PMM_{yscrR}) and the variables for the subset of existing must-run units located in EMM region r and fuel region R (UNTM_{yOH} and UNTM_{yOI}). The last term of Equation (3-37) describes maintenance for new capacity, so it is removed in this case because must-run capacity only involves existing units:

$$(3\text{-}37) \qquad \sum_{s} \text{SHOURS}_{s} \bullet \text{PMM}_{ysCrR} - 8.76 \bullet \text{CPMR}_{rC} \bullet \sum_{O} \sum_{H} \text{UNTM}_{yOH}$$

$$- 8.76 \bullet \text{CPMR}_{rC} \bullet \sum_{O} \sum_{I} \text{UNTM}_{yOI} \geq 0$$

for every coal capacity type C in season s and year y for fuel region R and EMM region r.

The analogous rows for non-coal capacity types have a similar form. The corresponding capacity variables EXD_{yrD} and EXDR_{yrD} are shared among the fuel regions R (using EXS_{yrRD} and EXSR_{yrRD}) and are substituted into the equation, as follows:

$$(3\text{-}38) \qquad \sum_{s} \text{SHOURS}_{s} \bullet \text{PMC}_{ysDrR} - 8.76 \bullet \text{CPMR}_{rD} \bullet \text{EXD}_{yrD} \bullet \text{EXS}_{yrRD}$$

$$- 8.76 \bullet \sum_{x} \text{CPMR}_{rD} \bullet \text{EXDR}_{yrDx} \bullet \text{EXSR}_{yrRD} - 8.76 \sum_{j=1}^{y} \sum_{E} \text{CPMR}_{rD} \bullet \text{BLD}_{jrRDE} \geq 0$$

for every non-coal dispatchable type D in year y in fuel region R and EMM region r.

For these non-coal capacity types, the corresponding equations for must-run plants are obtained using the corresponding decision planned maintenance decision variable (PMM_{ysDrR}) and the existing capacity ($\text{EXDM}_{yrD} \bullet \text{EXSM}_{yrRD}$). No retirements or additions of must-run capacity are assumed, so the last two terms of Equation (3-39) are removed. The resulting constraint is given by the following:

$$(3\text{-}39) \qquad \sum_{s} \text{SHOURS}_{s} \bullet \text{PMM}_{ysDrR} - 8.76 \bullet \text{CPMR}_{rD} \bullet \text{EXDM}_{yrD} \bullet \text{EXSM}_{yrRD} \geq 0$$

for every non-coal dispatchable type D in year y for fuel region R and EMM region r.

Electricity load requirements. These constraints are specified by vertical load segment, region, and year. Each load segment has a specific capacity (height) and energy (height multiplied by width) requirement. Because the load segment represents a fixed time slice, the capacity and energy requirements are directly proportional and can be measured in either capacity or energy units. That is, the energy

requirement for a given load segment can be obtained by multiplying the capacity requirement (GW) by the duration (hours) of that time period. For each load segment, this constraint requires that sufficient capacity is allocated to meet the corresponding capacity requirement (ELC_{yrls}), which corresponds to the height of the segment.

The energy requirements for each vertical segment can be satisfied by a number of different alternatives. First, the energy may be produced by operating dispatchable technologies in one or more capacity factor modes. For example, conventional steam capacity can be operated in base or intermediate modes. In base mode, one unit of capacity would contribute energy to all load segments. If the same capacity is operated in intermediate mode, then it would not contribute to those load segments with lower capacity requirements. The contribution of a dispatchable coal capacity type towards meeting the requirements for a given load segment is the product of the coal capacity assigned to that mode of operation (OPC_{yrRCms} and $OPCM_{yrRCms}$) and the corresponding derating factors (ELA_{yrCmsl}). Similarly, the contribution for dispatchable non-coal capacity is the product of the operate variables ($OPD_{yrRDfms}$ and $OPDM_{yrRCms}$) and their derating factors (ELA_{yrDmsl}).

Second, capacity using renewable energy sources (excluding intermittent technologies) such as geothermal, biomass, or municipal waste contribute to load. These technologies are used to their full capability subject to energy resource constraints. For non-hydro renewables, the capacity can be operated at the average capacity factor uniformly over all the load segments. For biomass, the contribution to load is the product of the capacity (OPB_{yrR}) and the corresponding derate capacity factor (ELB_{yr}). Similarly, the term for other non-hydro renewables is the capacity (OPR_{yrn}) and the corresponding derate factor (ELR_{yrn}). For hydroelectric plants, the capacity constraint is converted to an energy constraint, and capacity utilization (OPH_{yrl}) is determined independently for each load segment. Each operate vector is bounded at the existing capacity, thus precluding the addition of new unplanned capacity.

Generating capacity with intermittent energy sources (Existing - EXI_{yri}, New - INT_{yri}) can be used to satisfy energy requirements in those load segments for which input energy is fully or partially available. For example, load segments in which the sun is shining can use solar capacity. Also, load can be met from Canada's hydroelectric power (OCH_{yrh}). The REStore Submodule provides the net availability by time slice for intermittent technologies so that the capacity factors used in ECP reflect any need for curtailment. REStore also determines the most economical times to charge and discharge the battery storage technology, and ECP uses the net capacity factors from this solution, which can be positive or negative. Available resources to meet demand are also adjusted for electricity imports (TRE_{yersl}) and exports (TRE_{yrgsl}):

(3-40)

$$
\sum_{R}\sum_{C}\sum_{m} ELA_{yrCmsl} \cdot OPC_{yrRCms} + \sum_{R}\sum_{C}\sum_{m} ELA_{yrCmsl} \cdot OPCM_{yrRCms}
$$

$$
+ \sum_{R}\sum_{D}\sum_{f}\sum_{m} ELA_{yrDmsl} \cdot OPD_{yrRDfms} + \sum_{R}\sum_{D}\sum_{f}\sum_{m} ELA_{yrDmsl} \cdot OPDM_{yrRDfms}
$$

$$
+ \sum_{R} ELB_{yrs} \cdot OPB_{yrR} + \sum_{n} ELR_{yrn} \cdot OPR_{yrn}
$$

$$
+ \sum_{i}\sum_{E}\sum_{z=1}^{y} ELI_{zrislE} \cdot INT_{zri} \pm \sum_{E}\sum_{z=1}^{y} ELDS_{zrslE} \cdot DST_{zr} \pm ELXDS_{rsl} \cdot EXDS_{yr}
$$

$$
+ \sum_{i} ELXI_{risl} \cdot EXI_{yri} + ELR_{yrn|n=HY} \cdot OPH_{yrn} + \sum_{h} OCH_{yrh} - STX_{yrsl}
$$

$$
+ \sum_{e} TLOSS_{yer} \cdot TRE_{yersl} - \sum_{g} TRE_{yrgsl} + \sum_{e} TLOSS_{yer} \cdot TRECN_{yersl} \geq ELC_{yrsl}
$$

for every load step l in season s in year y and region r.

Spinning reserve requirements. The spinning reserve requirement is similar to the load requirement, where the contribution to spinning reserve is a function of the spinning reserve credit (SRCR$_C$) for technologies that supply reserves. For each load slice, SRRH$_r$ times the load height plus SRRD$_r$ times the difference between the seasonal peak and load slice height equals the spinning reserve requirement for that slice. Intermittent renewable technologies increase the need for spinning reserve (SRINT$_i$). Battery storage can provide spinning reserves, based on the capacity available determined by the REStore Submodule. Solar PV hybrid appears twice in the constraint because the battery portion can also contribute spinning reserves. If spinning reserve credit is allowed to be supplied across regions, then the fraction of credit (SRTC) multiplied by the quantity of imports (SRE$_{yersl}$) or exports (SRE$_{ygrsl}$) capacity that is committed to serving spinning reserve is also taken into account:

(3-41)

$$
\sum_{R}\sum_{C}\sum_{m} SRCR_{C} \bullet \left(1 - ELA_{yrCmsl}\right) \bullet OPC_{yrRCms}
$$

$$
+ \sum_{R}\sum_{C}\sum_{m} SRCR_{C} \bullet \left(1 - ELA_{yrCmsl}\right) \bullet OPCM_{yrRCms}
$$

$$
+ \sum_{R}\sum_{D}\sum_{m} SRCR_{D} \bullet \left(1 - ELA_{yrDmsl}\right) \bullet OPD_{yrRDms}
$$

$$+ \sum_R \sum_D \sum_m SRCR_D \bullet (1 - ELA_{yrDmsl}) \bullet OPDM_{yrRDms}$$

$$+ \sum_R SRCR_{C=B} \bullet (1 - ELB_{yrs}) \bullet OPB_{yrR} + \sum_n SRCR_n \bullet (1 - ELR_{yrn}) \bullet OPR_{yrn}$$

$$+ \sum_E \sum_{z=1}^{y} SRCR_{C=S} \bullet SRDS_{zrslE} \bullet DST_{zrE} + SRCR_{C=S} \bullet SRXDS_{rsl} \bullet$$

$$+ \sum_E \sum_{z=1}^{y} SRCR_{C=PVH} \bullet SRPVH_{zrsl} \bullet INT_{zriE|i=PVH} + SRCR_{C=PVH} \bullet SRPVH_{yrsl} \bullet EXI_{yri|i=PVH}$$

$$- \sum_i \sum_E \sum_{z=1}^{y} ELI_{zrislE} \bullet SRINT_i \bullet INT_{zriE} - \sum_i ELXI_{risl} \bullet SRINT_i \bullet EXI_{yri}$$

$$+ SRCR_{n=H} \bullet (1 - ELR_{yrn=H}) \bullet OPH_{yrl} + \sum_e TLOSS_{yer} \bullet SRE_{yersl} \bullet SRTC - \sum_g SRE_{yrgsl} \bullet SRTC$$

$$\geq SRRH_r \bullet ELC_{yrsl} + SRRD_r \bullet (Max_l(ELC_{yrsl}) - ELC_{yrsl})$$

for every load step l in season s in year y and EMM region r. In the equation above, C=B indicates the capacity type C is a biomass plant, C=S indicates battery storage and C=PVH is for solar PV hybrid.

Transmission constraints. Because electricity can be transmitted in either direction, the first set of paired constraints establishes that the total new transmission capacity that is available for transfers between two regions e and g (BLY_{yeg} or BLY_{yge}) is equal to the sum of the corresponding interregional capacity built to-date in both directions (BLX_{Jeg} and BLX_{Jge}):

(3-42)
$$- \sum_{J=1}^{y} \mathbf{BLX_{Jeg}} - \sum_{J=1}^{y} \mathbf{BLX_{Jge}} + \mathbf{BLY_{yeg}} \leq \mathbf{0}$$

(3-43)
$$- \sum_{J=1}^{y} \mathbf{BLX_{Jeg}} - \sum_{J=1}^{y} \mathbf{BLX_{Jge}} + \mathbf{BLY_{yge}} \leq \mathbf{0}$$

for every adjacent export/import pair e and g in year y.

For each electricity import region g, these equations limit the total amount of power that can be imported from other regions e by the incoming existing and new interregional transmission capability for region g. For stability purposes, the new transmission capacity is assumed to be derated (TDER) so that the flows do not overload the lines. These imports are limited as follows:

(3-44)
$$\sum_e \mathbf{TRE_{yegsl}} + \sum_e \mathbf{SRE_{yegsl}} - \mathbf{TDER} \bullet \sum_e \mathbf{BLY_{yeg}} \leq \mathbf{IMP_{ygsl}}$$

for every load step l in season s in year y and import region g.

The corresponding limits for exports are given by:

(3-45)

$$\sum_g \mathbf{TRE_{yegsl}} - \mathbf{TDER} \bullet \sum_g \mathbf{BLY_{yeg}} \leq \mathbf{EXP_{yesl}}$$

for every load step l in season s in year y and export region e.

The following set of equations limit the seasonal flows between specific trading regions by the available transmission capacity:

(3-46)

$$\mathbf{TRE_{yegsl}} - \mathbf{BLY_{yeg}} \leq \mathbf{EXT_{yegs}}$$

for every load step l in season s in year y between export region e and import region g.

Regional renewable credits (GRPS$_{yeg}$) can also be traded from region e to region g, as specified in Equation (3-47):

(3-47)

$$GRPS_{yeg} - \sum_s \sum_l TLOSS_{yeg} \cdot LHRS_l \cdot TRE_{yegsl} \leq 0$$

for every adjacent export/import pair e and g in year y.

The first term describes the net renewable credits traded from region e to region g, and the second term represents the equivalent electricity transfer between regions. Therefore, the renewable portfolio standard (RPS) credits transferred cannot exceed the total electricity traded.

State renewable credits (TRD$_{t'egy}$) can also be traded from region e to region g, as specified in Equation (3-48):

(3-48)

$$\sum_{Z(g)} \sum_n TRD_{t'egy} - \sum_s \sum_l TLOSS_{yeg} \cdot LHRS_l \cdot TRE_{yegsl} \leq 0$$

for every adjacent export/import pair between region e and any state in g in year y.

The first term describes the net state-level renewable credits traded from region e to any state Z in region g, Z(g). State-level RPS rules are particular to individual renewable technologies n. A particular pairing between state Z within region g and its targeted renewable technology n is called a tranche t'=(Z,n). The second term represents the equivalent electricity transfer between regions. Therefore, the sum of all applicable state RPS credits transferred cannot exceed the total electricity traded.

Production balance rows. These equations limit production of electricity by the available generating capability, which includes existing and new units, if appropriate. Negative terms define the available capacity while positive terms represent the disposition of capacity. These constraints are specified for both dispatchable and renewable technologies.

Coal. These constraints ensure that the coal capacity allocated to meet demand (OPC_{yrRcms}) does not exceed the available capacity, which consists of existing units ($UNIT_{yrROH}$), and if appropriate, new capacity (BLD_{yrRcE}).[21] The available capacity is adjusted for planned maintenance (PMC_{yrRcs}). These equations also determine retirements for coal-fired generator units. The objective function coefficient of the existing capacity contains the costs of continuing to operate that capacity (fixed operating and maintenance, capital expenditures for equipment, etc.). If ECP determines that it is not cost-effective to continue using this capacity, the solution value for $UNIT_{yrROH}$ will be less than the available capacity. The difference between the available capacity and the solution represents the retired capacity. For coal-fired generator units O of uncontrolled configuration type H, the production balance rows are given by the following:

$$(3\text{-}49) \qquad \sum_m \mathbf{OPC}_{yrRCms} + \mathbf{PMC}_{ysRrC} - \sum_{J=1}^{y} \sum_E \mathbf{BLD}_{jrRDE} - \sum_o \mathbf{UNIT}_{yrROH} \ \leq \ \mathbf{0}$$

for every coal capacity type C in season s in year y for fuel region R and EMM region r.

The above equations exclude must-run coal capacity, which has a separate, but similar, set of constraints.

$$(3\text{-}50) \qquad \sum_m \mathbf{OPCM}_{yrRCms} + \mathbf{PMM}_{ysRrC} - \sum_o \mathbf{UNTM}_{yrROH} \ \leq \ \mathbf{0}$$

for every uncontrolled coal capacity type C in season s in year y for fuel region R and EMM region r.

The analogous constraints for existing coal-fired generator units of controlled configuration type I are derived by substituting the decision variables for dispatchable units ($UNIT_{yrROI}$) into Equation (3-49) and must-run plants ($UNITM_{yrROI}$) into (3-50).

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[21] Coal capacity is represented at the unit level to determine retrofits for pollution control equipment, which tend to be site-specific. Because these decisions are not included for other fossil fuel technologies, existing oil and natural gas capacity is represented at a more aggregate level.

Natural Gas/Oil. For each non-coal capacity type, region, year, and season, these equations limit production of electricity by the available generating capability, adjusted for planned maintenance (PMC_{yrsD}). Existing capacity includes units that have announced retirement dates (EXD_{yrD}) and units that can be retired if the capacity is considered uneconomical ($EXDR_{rDx}$). Like coal, these capacity types have fixed costs that are incurred if the capacity remains available. Some technologies can also increase capacity by building new plants (BLD_{yrDE}). If the ECP determines that it is not cost-effective to continue using existing capacity, the solution value for $EXDR_{rDx}$ will be less than the available capacity, which effectively specifies the retired capacity. The non-coal production balance rows are represented as follows:

$$(3\text{-}51) \quad \sum_f \sum_m \mathbf{OPD_{yrRDfms}} + \mathbf{PMC_{ysrRD}} - \sum_{J=1}^{y} \sum_E \mathbf{BLD_{jrRDE}}$$
$$- \mathbf{CSHR_{yrRD}} \bullet \mathbf{EXD_{yrD}} - \sum_x \mathbf{CSHR_{yrRD}} \bullet \mathbf{EXDR_{yrDx}} \leq 0$$

for every non-coal dispatchable capacity type D in season s and year y in fuel region R and EMM region r.

Must-run plants have a similar set of production balance rows, but this set excludes retirements, interregional transfers, and new capacity because these decisions are not considered for must-run capacity. The appropriate equations are specified as follows:

$$(3\text{-}52) \quad \sum_f \sum_m \mathbf{OPDM_{yrRDfms}} + \mathbf{PMM_{ysrRD}} - \mathbf{EXDM_{yrRD}} \leq 0$$

for every non-coal dispatchable capacity type D in season s and year y in fuel region R and EMM region r.

Renewables. Renewable capacity is represented in much the same way as dispatchable technologies. However, the utilization of non-hydro renewable plants is typically determined by the availability of the energy source, so there is only one operate decision. For hydroelectric capacity, the utilization rates are determined from historical generation, which is assumed to account for any restrictions on water usage:

$$(3\text{-}53) \quad \mathbf{OPR_{yrn}} - \sum_{j=1}^{y} \sum_E \mathbf{RNW_{jrnE}} - \mathbf{EXR_{yrn}} \leq 0$$

for every renewable capacity type n in year y in EMM region r.

For existing hydro capacity, the electricity production is based on the available water supply. However, the water is typically stored in a reservoir so there is flexibility in operating the plants. The decision variable for operating hydro capacity ($OPHyrls$) can be partially or fully allocated for any load segment, but the hydro production balance rows limit the total production by the seasonal capacity factor (CFR_{yrns}):

(3-54)
$$\sum_{l} \mathbf{OPH_{yrl}} \bullet \mathbf{ELR_{yrl}} / \mathbf{CFR_{yrns}} - \mathbf{EXH_{yrs}} \leq 0$$

for every season s in year y in EMM region r.

Similar constraints exist for pumped storage and demand storage, which can also be operated in any time slice, subject to a limit on the total production in each season. However, the storage technologies also require that their generation be replaced by other sources in other time periods.

Storage requirements. The generation provided by pumped storage and demand storage technologies must be replaced in other time periods. A factor, STFAC$_i$, indicates the total amount of storage replacement needed for storage technology i. For traditional pumped storage capacity, this factor is assumed to be 1.20, requiring 20% more generation to replace what is provided by the technology. For demand storage, a factor of 1.0 would be used to model simple load shifting, or a factor below 1.0 could be used to model peak-shaving, where some of the demand is simply reduced at peak and not used later:

(3-55)
$$\sum_{l} \mathbf{OPH_{yrl}} \bullet \mathbf{STFAC_i} \bullet \mathbf{LHRS_l} - \sum_{l} \mathbf{LHRS_l} \bullet \mathbf{STX_{yrsl}} \leq 0$$

for every season s in year y in EMM region r, for pumped storage or demand storage technology i.

Coal capacity balance row. Planning decisions for coal capacity include several different options, including maintaining the current configuration (UNIT$_{yOH}$), retrofitting with emissions controls (UNIT$_{yOI}$), improving the heat rate (HRI$_{yOH}$ and HRI$_{yOI}$), or converting to 100% natural gas (CGC$_{yO}$) or converting to coal and natural gas cofiring (CGC$_{yO}$ + CGCL$_{yO}$). The capacity balance rows, which ensure that the allocation of capacity for these options does not exceed the existing capacity, are given as follows:

(3-56)

$$UNIT_{yOH} + \sum_{I} UNIT_{yOI} + HRI_{yOH} + \sum_{I} HRI_{yOI} + CGC_{yO} + CGCL_{yO} \leq EXC_{yO}$$

for each coal capacity group O in year y.

If the available capacity is not allocated to any of these options and the capacity has at least three years of negative net revenues (in other words, costs exceed revenues), then the capacity is retired.

Coal-gas cofiring capacity balance row. Planning decisions for coal-gas cofiring need to ensure that if any part of current coal capacity with existing emission control configurations is considered to be kept as is (CGCL$_{yO}$), the capacity to be converted to gas (CGC$_{yO}$) should be always chosen proportionally based on predefined max coal and natural gas shares. The capacity balance rows are given as follows:

(3-57)

$$CGFSH \cdot CGC_{yO} \geq (CGFSH - 1) \cdot CGCL_{yO}$$

Combined-cycle capacity balance row. Planning decisions for existing combined-cycle capacity include continuing to operate the current configuration ($UNCC_{yV}$) or retrofitting with carbon capture and sequestration equipment (RCC_{yV}). The allocation of combined-cycle capacity constraint is as follows:

(3-58)

$$UNCC_{yV} + RCC_{yV} + \le EXCC_{yV}$$

for each combined-cycle capacity group V in year y.

If neither option is chosen and if the unused capacity has at least three years of negative net revenues, then the capacity is retired.

Non-coal fossil steam capacity balance row. Planning decisions for existing fossil steam determine whether or not to continue operating existing capacity. The difference between the capacity utilized ($UNFS_{yV}$) and the available capacity ($EXFS_{yV}$) represents the unused capacity. If the capacity is not needed and has at least three years of negative net revenues, then the capacity is retired. The capacity balance rows for non-coal fossil steam are represented as follows:

(3-59)

$$UNFS_{yW} \le EXFS_{yW}$$

for each non-coal fossil steam capacity group W in year y.

Nuclear capacity balance row. Because nuclear capacity has low operating costs and is typically operated at its maximum utilization rate, production balance rows are not necessary. For nuclear capacity, the balance rows determine only the retirement decisions. The decision variable $UNTN_{yrU}$ describes the amount of capacity that the ECP determines is economical to operate. That is, if the decision variable is activated, then the operating costs are incurred. The difference between $UNTN_{yU}$ and the available capacity, NUC_{yU}, represents the unused capacity. The capacity is retired if it is unused and has at least six years of negative net revenues. The capacity balance row for nuclear is given by the following:

(3-60)

$$UNTN_{yU} \le UNC_{yU}$$

for each nuclear capacity group U in year y.

Zero-emission-credit constraint. Some states, such as Illinois and New York, have passed legislation to subsidize specific nuclear power plants that may be at risk because competition from other generation sources could result in revenues (based on marginal energy prices) that are insufficient to cover their operating costs. Qualifying units in these states with negative net revenues will receive a subsidy to cover the difference and keep them operating. The following constraint ensures that the nuclear capacity receiving this subsidy continues to operate and does not retire.

(3-61)

$$\sum_{U}\sum_{r(Z)}\sum_{m}\sum_{s}\sum_{l} ELA_{yrUmsl} \cdot LHRS_l \cdot UNTN_{yUr(Z)} \geq NUCSUB_{yZ}$$

for nuclear capacity type C in each state Z of r(Z) with zero-emission subsidies in year y, where r(Z) returns all EMM regions that state Z comprises.

The term ELA_{yrCmsl} represents the utilization rate in a given load segment, and $LHRS_l$ represents the hours (in thousands) in each load segment. Summing over the seasons and load segments and multiplying these two terms by the capacity of a nuclear unit $UNTNST_{yUr(Z)}$ describes the generation from unit U. The right-hand side $NUCSUB_{yZ}$ is the expected generation from subsidized nuclear units if they were profitable. The cost of the subsidy payments is recovered through retail prices as an adder to the electric distribution price component to represent the purchase of ZECs by load-serving entities.

The ECP uses this same logic to represent the civil nuclear credit program passed as part of the Infrastructure Investment and Jobs Act. The model assumes additional programs in competitive states that do not already have state programs; however, the costs for the federal program do not pass through to retail prices.

Reserve margin requirement. The reserve margin constraints ensure that the planning decisions that increase supply by adding new generating capability are sufficient to satisfy regional reliability requirements. Planning decisions to add capacity will have to be implemented if the total capacity requirement (RMQ_{yr}) exceeds the sum of the existing coal capacity ($\sum_O UNIT_{yOH} + \sum_O \sum_I UNIT_{yOI} + \sum_O HRI_{yOH} + \sum_O \sum_I HRI_{yOI} + \sum_O CGC_{yOH} + \sum_O CGCL_{yOH}$), combined-cycle capacity ($\sum_V UNCC_{yV} + \sum_V RCC_{yV}$), non-coal fossil steam capacity (($\sum_W UNFS_{yW}$), other dispatchable capacity ($\sum_D EXD_{yrD} + \sum_D EXDM_{yrD} + \sum_D EXDR_{yrDx}$), renewable capacity ($\sum_n EXR_{yrn}$), intermittent capacity ($\sum_i EXI_{yri}$), and diurnal storage capacity ($EXDS_{yr}$). Available capacity can be increased by building new capacity—either dispatchable (BLD_{yrcE}), renewable (RNW_{yrnE}), intermittent (INT_{yriE}), or diurnal (battery) storage (DST_{yrE}). For intermittent and diurnal storage technology, its capacity credit (RMI_{yri} for intermittent and RMS_{yr} for storage) will depend on its ability to provide electricity when the peak demand occurs. In addition, the amount of available capacity is affected by transmission capability for imports to region r and exports from region r (BLX_{yer} and BLX_{yrg}). Distributed generation technologies (DGN_{yrt}) operate during peak load and also contribute to reliability.

The reserve margin constraint is formulated as follows:

(3-62)

$$
\begin{aligned}
\sum_c \sum_{j=1}^{y} \sum_E BLD_{jrcE} &+ \sum_i \sum_{j=1}^{y} \sum_E INT_{jriE} \cdot RMI_{jri} + \sum_{j=1}^{y} \sum_E DST_{jrE} \cdot RMS_{jr} \\
&+ \sum_n \sum_{j=1}^{y} \sum_E RMR_{jrn} \cdot RNW_{jrnE} + \sum_O UNIT_{yHO} + \sum_O \sum_I UNIT_{yOI} \\
&+ \sum_O HRI_{yOH} + \sum_O \sum_I HRI_{yOI} + \sum_O CGC_{yOH} + \sum_O CGCL_{yOH} \\
&+ \sum_V UNCC_{yV} + \sum_V RCC_{yV} + \sum_w UNFS_{yw} \\
&+ \sum_D EXD_{yrD} + \sum_D EXDM_{yrD} \\
&+ \sum_n RMR_{jrn} \cdot EXR_{yrn} + \sum_i RMI_{jri} \cdot EXI_{yri} + RMS_{jr} \cdot EXDS_{yr} \\
&\sum_D \sum_x EXDR_{yrDx} + \sum_t \sum_q DGN_{yrqt} + \sum_e TDER \cdot BLX_{yer} \\
&- \sum_g TDER \cdot BLX_{yrg} \geq RMQ_{yr}
\end{aligned}
$$

for every year y and EMM region r.

The reserve margin requirement (RMQ_{yr}) specifies the amount of capacity in excess of the projected peak demand that is needed in case of unanticipated supply outages or unexpected demand levels. Reserve margins are typically established for each region by its governing body—public utility commission, NERC region, or Independent System Operators (ISOs)/Regional Transmission Operators (RTOs). Because of uncertainty and differences in how these entities measure peak demand and account for capacity accreditation for renewable and battery technologies relative to how they are measured in our modules, we do not use reported reserve margins directly. We calculated the implied reserve margin for 2024 from the model output to reflect the achieved levels and assumed those would be maintained, ranging from 1% to 19%. We used the reference reserve margins reported to NERC as a maximum value if our calculated values were higher.[22]

Intermittent build limit. The limits on new intermittent capacity result from a combination of resource constraints and new technology penetration limits:

(3-63)
$$
\sum_{j=1}^{y} \sum_E INT_{jriE} \leq INTL_{ir}
$$

for every intermittent technology i and EMM region r.

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[22] North American Electric Reliability Corporation, 2021 Long-Term Reliability Assessment (December 2021).

Renewable build limit. The limit on new renewable capacity results from a combination of resource constraints and new technology penetration limits:

$$(3\text{-}64) \qquad \sum_{j=1}^{y} \sum_{E} RNW_{jrnE} \leq RNWL_{nr}$$

for every renewable capacity type n and EMM region r.

Distributed generation build limit. These build limits represent the supply curves for avoiding transmission and distribution expenditures by adding distributed generation rather than central-station generating capacity. Depending on the location of different load centers, the cost of adding T&D equipment can vary considerably. These constraints describe the amount of distribution generation that could be added in year y, region r, and supply step q, which corresponds to a specific level of avoided T&D costs:

$$(3\text{-}65) \qquad \sum_{t} DGN_{yrtq} \leq DGNL_{yrq}$$

for every supply step q in EMM region r in year y.

Demand storage build limit. The load shifting technology (when available – this technology is turned off for AEO2025) is very attractive because of its ability to avoid peak operating costs. However, there is a limit to how much the demand can be reduced as a result of these methods, which require customers to curtail load at peak times. A fixed input assumption determines the maximum percentage of peak load that can be met by the demand storage technology in each year, and this constraint limits total demand storage capacity to STLIM$_{yr}$, which is the input percentage for the year multiplied by the peak demand in the region:

$$(3\text{-}66) \qquad BLST_{yr} + EXST_{yr} \leq STLIM_{yr}$$

for every EMM region r in year y.

FGD retrofit limit. This national-level row limits annual FGD retrofits, which convert unscrubbed capacity type C to scrubbed capacity type, to reflect industry constraints on the amount of scrubber capacity that can be installed. If UNIT$_{yOI}$ represents the subset of coal-fired generator units O currently without scrubbers that are retrofitted to a controlled configuration I in year y, then the limit is defined as follows:

$$(3\text{-}67) \qquad \sum_{O} \sum_{I} UNIT_{yOI} \leq FGDL_{y}$$

for every year y.

CCS retrofit limit. As with scrubbers, this national-level row limits annual CCS retrofits. If UNIT$_{yOI}$ represents the subset of coal-fired generator units O currently without CCS equipment that are converted to a carbon-controlled configuration I in year y, then the limit is specified by the following:

$$(3\text{-}68) \qquad \sum_{O} \sum_{I} UNIT_{yOI} \leq CCSL_{y}$$

for every year y.

Intermittent generation limits. These constraints, which limit the amount of generation produced by intermittent renewable technologies to maintain stability in the transmission system, are described below:

(3-69)

$$\sum_i \sum_s \sum_l ELI_{yrisl} \bullet EXI_{yri} + \sum_i \sum_{j=1}^{y} \sum_s \sum_l \sum_E ELI_{yrisl} \bullet INT_{jriE} - PINT_{yr} \bullet GEL_{yr} \leq 0$$

for every region r and year y.

Renewable portfolio constraint. Many of the federal and state proposals for deregulating the electric power industry include renewable portfolio standards (RPS). An RPS specifies that electricity suppliers must produce a minimum level of generation using renewable technologies.

Producers with insufficient renewable generating capacity can either build new plants or purchase credits from other suppliers with excess renewable generation.

The RPS proposals differ according to their respective definitions of renewable technologies. Typically, RPS proposals include solar, wind, biomass, and geothermal, but some proposals exclude generation from hydroelectric or municipal solid waste plants, or both. The required level of renewable generation also varies as well as the formula for computing the percentage of renewable generation. In some cases, the minimum requirement specifies the level of renewable sales relative to total sales. Alternative proposals consider renewable generation as a percentage of total sales or as a percentage of total nonhydroelectric sales.

In ECP, adding a set of constraints that specify the minimum level of renewable generation for a given year represents the RPS proposals. Regional and national equations are included to represent the respective requirements, if appropriate. This structure is not currently used in the projections, instead a more detailed state-level RPS program described in the next section is in place. The decision variable RPSR$_{yr}$ describes the qualifying renewable generation in region r. If a given region has a RPS requirement, this variable has a lower bound corresponding to the required generation as a percentage of electricity sales. The regional rows are represented as follows:

(3-70)

$$\sum_i \sum_s \sum_l ISHR_i \cdot ELI_{yisl} \cdot LHRS_l \cdot (EXI_{yri} + \sum_{z=l}^{y} \sum_E INT_{zriE})$$

$$+ \sum_n \sum_l RSHR_n \cdot ELR_{yrn} \cdot LHRS_l \cdot (EXR_{yrn} + \sum_{z=l}^{y} \sum_E RNW_{zrnE})$$

$$+ \sum_A \sum_B \sum_N \sum_C RSHR_n \cdot TBM_{yABNC} \cdot 1000/HRC_{yNC}$$

$$+ TLOSS_{yer} \cdot GRPS_{yer} - GRPS_{yrg} - RPSR_{yr} \geq 0$$

for every region r and year y.

The first term of the inequality accounts for generation from existing and new intermittent technologies. For each load segment l, the derating factor (ELI_{yrisl}) describes the fraction of total capacity that is utilized in that segment (in other words, adjusted for forced outages and load following). The product of this utilization rate and the hours in load segment l ($LHRS_l$) yields the generation per unit of capacity. Summing over all load segments and then multiplying by the available capacity ($EXI_{yri} + \sum\sum INT_{zriE}$) and the fraction of generation credited towards RPS ($ISHR_i$) gives the intermittent generation that satisfies the minimum renewable requirement. Similarly, the second term describes the generation from dispatchable renewable capacity. The third term represents renewable generation from cofiring biomass with coal. Dividing the biomass fuel consumption from cofiring (TBM_{yABNC}) by the heat rate yields the corresponding generation. Multiplying this quantity by the RPS credit for biomass ($RSHR_n$) provides the qualifying renewable generation from biomass cofiring. The fourth term ($TLOSS_{yer} \bullet GRPS_{yer}$) represents the net renewable credits transferred from export region e to region r The fifth term ($GRPS_{yrg}$) specifies the renewable generation credits sent from region r to import region g. The final term (RPS_{yr}) represents the renewable generation requirement for region r in year y.

The renewable credit price is based on the marginal cost of complying with the renewable generation requirement, which is represented by the dual value (shadow price) of the national or regional RPS constraint. The objective function of ECP minimizes the present value of investment and operating costs, in nominal dollars, for the planning horizon. Therefore, the dual value of the RPS constraint for a given year provides the nominal present value of the marginal cost of compliance in that year. The renewable credit price is assumed to be the real dollar equivalent of the dual value. The national RPS credit price is computed as follows:

(3-71) $$EPRENEW_y \bullet (1 + AVGDCR_y)^y / UPGNPD_y$$

for the year y that corresponds to the first year in the planning horizon that new renewable capacity can be built to comply (y=1+lead time),

where

$EPRENEW_y$	=	Discounted, Annual Compliance Cost (dual value) in Year y (Mills per Kilowatthour in Nominal Dollars);
$AVGDCR_y$	=	Average Discount Rate for Year y (Scalar); and
$UPGNPD_y$	=	Cumulative Inflation Factor for Year y (Scalar).

Similarly, the regional RPS credit price is based on the dual value of the regional RPS limit ($EPRENEWR_{yr}$) and is given by the following:

(3-72) $$EPRENEWR_{yr} \bullet (1 + AVGDCR_y)^y / UPGNPD_y$$

State renewable portfolio constraint. A state RPS specifies that electricity suppliers must produce a minimum level of generation using a single or limited groups of multiple renewable technologies. A unique pairing between a state and a particular renewable technology is called tranche t'. A single state

can have multiple tranches. States with insufficient renewable generating capacity can either build new plants or purchase credits from other suppliers with excess renewable generation.

(3-73)

$$-\sum_{r} RNSHR_{Z(r)} \cdot REQ_{t'y|t'=T(Z(r),n)} \cdot SALES_{ry}$$

$$+\sum_{r} PCNT_{t'=T(Z(r),n)} \cdot GEN_{t'ry|t'=T(Z(r),n)}$$

$$+\sum_{r}\sum_{e} PCNT_{t'=T(Z(r),n)} \cdot TRD_{t'ery|t'=T(Z(r),n)}$$

$$+\sum_{r}\sum_{f} RNSHR_{Z(r)} \cdot MULTI_{t'=T(Z(r),n)} \cdot CHP_{Z(r)fy} + \sum_{r} GXCOF_{Z(r)y}$$

$$+\sum_{r} MULTI_{t'=T(Z(r),n)} \cdot DG_{t'y|t'=T(Z(r),n)} \geq 0$$

where

$RNSHR_{Z(r)}$ = a parameter, share of EMM region r sales that come from state Z(r) (in region r);

$REQ_{t'ny}$ = a parameter, RPS requirement for tranche t'=T(Z(r), n) and plan year y;

$SALES_{ry}$ = a fixed vector, total sales for EMM region r in projection period y;

$PCNT_{t'}$ = a parameter, percentage of tranche t'= T(Z(r), n) that satisfies the RPS requirements in state Z(r) and technology n;

$GEN_{t'ry}$ = a vector, generation from tranche t'= T(Z(r), n), EMM region r in projection period y;

$TRD_{t'ery}$ = a vector, generation from tranche t'= T(Z(r), n) from EMM export region e to EMM import region r in projection period y;

$CHP_{Z(r)fy}$ = Fixed vector to credit any combined heat and power (CHP) that qualifies for RPS requirement for state Z(t), CHP fuel f projection period y;

$GXCOF_{Z(r)y}$ = Total cofiring generation by state Z(r) in projection period y, slack variable in RPS state cofiring balancing row;

$DG_{t'y}$ = Fixed vector to credit any distributed generation that qualifies for RPS requirement for tranche t' = T(Z(r),n) and projection period y; this excludes any distributed PV generation that is explicitly accounted for in the ECP formulation.

Technology penetration

ECP contains a component that represents changes in cost and performance characteristics for different capacity types, particularly new technologies. ECP also addresses initial cost estimates (technological optimism), cost reductions as commercialization occurs (learning), uncertainty associated with capacity expansion (risk), and efficiency improvements.[23] This component also contains a market-sharing

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[23] For greater detail on the methodology for technological optimism, learning, and risk, see U.S. Energy Information Administration, *NEMS Component Design Report, Modeling Technology Penetration* (Washington, DC, March 1993). The inputs

algorithm, which reallocates capacity expansion decisions from the LP model based on the competitiveness of technologies that were not selected.

Technological optimism. Cost assumptions for technologies that are already in commercial operation are based on available cost data. The initial cost inputs include an allowance for project contingency.[24]

However, no data exists on realized costs for new technologies. As a result, capital costs for new generating technologies are based on engineering estimates. ECP incorporates a technological optimism factor, which is an additional contingency rate that represents the tendency to underestimate costs for new technologies.[25] The accuracy of cost estimates is directly related to a technology's stage of development. These estimates become better as a technology progresses toward commercialization.

The technological optimism factor is calculated for each major design component of new technologies (Table 4). Often a new technology design incorporates parts of existing designs, which will have less uncertainty in the cost estimates. Because the optimism factor is calculated by component, only the new, untested parts of the design will have the cost adjustment over time. Multiple technologies may share components, and in those cases new capacity built of one plant type will contribute to lowering the technological optimism for another plant type. Some plant types have not been explicitly modeled as having components where there are no large opportunities for cross-technology learning.

Technological optimism is assumed to occur for a specified number of units. The initial technological optimism factor applied to the first-of-a-kind cost is also an input (for example, a 10% technological optimism factor equals 1.10). This factor is assumed to decrease linearly until the actual costs and estimates are the same (the factor equals 1.00).

The number of units currently operational is estimated by dividing the available capacity by the typical unit size. The total capacity for each component is the sum of the capacity for all plant types that include that component, weighted by the share that the component contributes to the total capacity of the plant type (Table 6). The slope of the line that describes the decrease in the technological optimism factor is given by the following:

(3-74)
$$\mathbf{SLOPE_D = (1 - OPTFACO_D)/(UNITL_D - UNITB_D)}$$

where

OPTFACO$_D$ = Initial Technological Optimism Factor for Design Component D;

UNITL$_D$ = Number of Units of Capacity with Component Type D Completed When Technological Optimism is No Longer Observed; and

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for these factors are contained in U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2025*, DOE/EIA-0554(2025) (Washington, DC, April 2025).

[24] A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements if costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur."

[25] For more information on technological optimism, see Independent Project Analysis, Incorporated, "An Analysis of the Potential for Cost Improvement in Emerging Power Generation Technologies" (Reston, VA, June 1993).

UNITB$_D$ = Number of Units of Capacity with Component Type D Completed When Technological Optimism Factor is First Applied (in other words, 0).

The technological optimism factor OPTFAC$_{yD}$ for component type D in year y is then given by the following:

(3-75)
$$\mathbf{OPTFAC_{yD} \ = \ OPTFACO_D + SLOPE_D \bullet UNITS_{yD}}$$

for UNITS$_{yD}$ < UNITL$_D$

where

UNITS$_{yD}$ = Number of Units of Capacity with Component Type D Completed by Year y.

For a given component, the factor is set to 1.0 once the number of units in operation reaches the level in which technological optimism is no longer observed.

The technological optimism factor OPTFAC$_{yc}$ for a given technology c is calculated from a weighted average of the factors for each design component:

(3-76)
$$\mathbf{OPTFAC_{yC} \ = \ \sum_D CSTWT_{CD} \cdot OPTFAC_{yD}}$$

where

CSTWT$_{cD}$ = Share of Initial Cost Estimate of Capacity Type c contributed by Design Component D.

Learning methodology. ECP uses a learning curve approach to model the commercialization of generating technologies. The learning methodology represents learning-by-doing effects, which indicate that costs fall as experience increases. Experience is measured using cumulative capacity. An assumed rate of cost reduction is applied to each doubling of capacity. For simplicity, this rate of cost reduction is called the slope of the learning curve. As for the technological optimism factor, the learning factor is first calculated by design component.

A final component by plant type is calculated as a weighted average of the individual component factors, using the contribution of each component to the overall technology cost estimate as the weight.

A three-step learning curve is used for all design components. Typically, the greatest amount of learning occurs during the initial stages of development, and the rate of cost reductions declines as commercialization progresses. Each step of the curve is characterized by the learning rate and the number of doublings of capacity in which this rate is applied. Depending on the stage of development for a particular component, some of the learning may already be incorporated in the initial cost estimate.

Mathematically, the cost for capacity level N can be expressed as follows:

(3-77)
$$\mathbf{C_N = C_I \cdot (\frac{N}{I})^b}$$

where

C_N	=	Cost at current capacity level (dollars per kilowatt);
C_I	=	Initial cost estimate (dollars per kilowatt);
N	=	Current capacity; and
I	=	Initial capacity (set to typical unit size if no units online).

Rearranging Equation (3-81), the exponent for each step b(s) can be determined by letting (N/I) equal 2 (in other words, considering a doubling of capacity). That i:

(3-78)
$$b(s) = \ln\,(1 - LCR_S)/\ln(2)$$

where

LCR_s	=	cost reduction for every doubling of capacity in step s (fraction).

Note that b(s) is negative so that as (N/I) increases the corresponding cost decreases. That is:

(3-79)
$$C_2 = C_1 \cdot 2^{b(s)};\ C_4 = C_1 \cdot 4^{b(s)};\ C_8 = C_1 \cdot 8^{b(s)};\cdots$$

The cost reductions continue until the number of doublings completed reaches a prespecified level, when learning-by-doing effects are assumed to be no longer observed. Capital cost input data used in the ECP represent initial cost estimates as of the most recent historical year (C_I), so the learning factor associated at capacity level N, LF_N, is expressed as a multiplier of C_I. That is, LF_N describes the decrease in capital costs between the initial estimate and the Nth-of-a-kind units:

(3-80)
$$C_N = C_1 \cdot LF_N$$

Substituting the right-hand side of (3-81) for C_N in equation (3-81) yields:

(3-81)
$$LF_N = (\frac{N}{I})^{b(s)}$$

A learning factor for each component is calculated each year, $LRNFAC_{yD}$. Just as with the technological optimism factor, a learning factor, $LRNFAC_{yc}$, for each plant type c is calculated from the learning factors by component:

(3-82)
$$LRNFAC_{ye} = \sum_{D} CSTWT_{cD} \bullet LRNFAC_{yD}$$

Technological improvements in heat rates. ECP can include improvements in heat rates, which describe the amount of fuel input required to produce a kilowatthour of electricity, for new technologies. For each type of technology, if an alternate heat rate is input for a future year, it is assumed that the annual

reduction in the heat rate is constant and occurs over the specified time period. The heat rate for technology type c in a particular year is given by the following:

$$\text{(3-83)} \quad \mathbf{EPPHRT_{yc} = EPPHRTO_c + (EPPHRTN_c - EPPHRTO_c) \cdot (\frac{y - UPDHRYO_c)}{UPDHRYN_c - UPDHRYO_c})}$$

$$\text{for } UPDHRYO_c \leq y \leq UPDHRYN_c$$

$$EPPHRT_{yc} = EPPHRTO_c \text{ for } y < UPDHRYO_c$$

$$EPPHRT_{yc} = EPPHRTN_c \text{ for } y > UPDHRYN_c$$

where

$EPPHRT_{yc}$	=	heat rate for technology type c in year y;
$EPPHRTO_c$	=	initial heat rate for technology type c;
$EPPHRTN_c$	=	final heat rate for technology type c;
$UPDHRYO_c$	=	last year for initial heat rate for technology type c (in other words, year before heat rate improvements begin); and
$UPDHRYN_c$	=	last year of learning for heat rate for technology type c.

Market-sharing algorithm. ECP contains a market-sharing algorithm, which revises the capacity expansion decisions from the LP model for each of the electricity supply regions. For a given region r, the total market ($TOTBAS_r$) is represented by the sum of the capacity expansion decisions that were selected (basic vectors). The market-sharing algorithm then reallocates some of this market to options that were not selected (nonbasic vectors), based on the following logit function:[26]

$$\text{(3-84)} \quad \mathbf{MS_i = MC_i^a / \sum_j MC_j^a}$$

where

MS_i	=	Market Share for the ith Technology
MC_i	=	Marginal Cost for the ith Technology
a	=	Exponent of Logit Function

In Equation (3-88), market shares are determined on the basis of marginal costs. In ECP, the competitiveness of the different technologies is compared using the reduced cost from the LP model, which describes the marginal cost reduction required for a particular option to be selected.[27] In this algorithm, MC_i is represented using the following ratio:

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[26] For more information on the function used in the market-sharing algorithm of the ECP, see U.S. Energy Information Administration, *NEMS Component Design Report Modeling Technology Penetration* (Washington, DC, March 1993).

[27] An option selected by the LP model has a reduced cost of zero.

(3-85)
$$\mathbf{CSTRATIO}_{\mathbf{yrRcE}} = (\mathbf{CBLD}_{\mathbf{yrRcE}} - \mathbf{RC}_{\mathbf{yrRcE}})/\mathbf{CBLD}_{\mathbf{yrRcE}}$$

where

$CSTRATIO_{yrRcE}$	=	Ratio of Required Cost to Actual Cost for Building Capacity Type c Beginning Operation in Year y in EMM Region r and Fuel Region R at Short-Term Supply Step E (Scalar);
$CBLD_{yrRcE}$	=	Investment Cost to Build Capacity Type c With Initial Online Year y in EMM Region r and Fuel Region R at Short-Term Supply Step E (Millions of Dollars/Gigawatt); and
RC_{yrRcE}	=	Reduced Cost to Build Capacity Type c With Initial Online Year y in EMM Region r and Fuel Region R at Short-Term Supply Step E (Millions of Dollars/Gigawatt).

Because RC_{yrcE} is between zero and $CBLD_{yrRcE}$ (a nonbasic vector with a larger reduced cost would need to have a negative investment cost to be selected), $CSTRATIO_{yrRcE}$ is less than or equal to one. A prespecified tolerance level, EPMSTOL, is used to eliminate options that are considered noncompetitive because the cost reduction required for penetration is too large. That is, $CSTRATIO_{yrRcE}$ is set to 0 if $CSTRATIO_{yrRcE}$ is less than (1 - EPMSTOL), so that the corresponding market share will be 0. After $CSTRATIO_{yrRcE}$ has been determined for all options evaluated by the market-sharing algorithm, this ratio is incorporated into Equation (3-84) to determine the individual market shares for each technology choice. That is:

(3-86)
$$\mathbf{MS}_{\mathbf{yrRcE}} = (\mathbf{CSTRATIO}_{\mathbf{yrRcE}})^{\mathbf{a}} / \sum_{\mathbf{y}} \sum_{\mathbf{c}} (\mathbf{CSTRATIO}_{\mathbf{yrRcE}})^{\mathbf{a}}$$

A less-competitive technology has a comparatively high reduced cost relative to its actual cost, thereby resulting in a lower value for $CSTRATIO_{yrRcE}$. When the exponent a is applied, the numerator in Equation (3-86) declines rapidly resulting in a lower market share compared with other technologies with higher values for $CSTRATIO_{yrRcE}$.

These market shares are then used to reallocate the capacity additions for each EMM region r determined by the LP model ($TOTBAS_r$) so that the same total capacity is added. The revised build decisions (BMS_{yrRcE}) for those capacity types not selected by the LP model are given by the following:

(3-87)
$$\mathbf{BMS}_{\mathbf{yrRcE}} = \mathbf{MS}_{\mathbf{yrRcE}} \cdot \mathbf{TOTBAS}_{\mathbf{r}}$$

Finally, the capacity expansion decisions that were selected by the LP model (BLP_{yrcE}) must be decreased to account for the total of the revised build decisions that was reallocated ($TOTNBS_r$). This decrease is accomplished by Equation (3-88) and Equation (3-89), which reduce each of the original decisions in proportion to their share of the total market:

(3-88)
$$\mathbf{TOTNBS}_{\mathbf{r}} = \sum_{\mathbf{y}} \sum_{\mathbf{R}} \sum_{\mathbf{c}} \sum_{\mathbf{E}} \mathbf{BMS}_{\mathbf{yrRcE}}$$

(3-89)
$$\mathbf{BLD'}_{\mathbf{yrRcE}} = \mathbf{BLD}_{\mathbf{yrRcE}} - \mathbf{TOTNBS} \cdot (\mathbf{BLD}_{\mathbf{yrRcE}}/\mathbf{TOTBAS}_{\mathbf{r}})$$

where

BLD$_{yrRcE}$ = Original LP Build Decision for Capacity Type c Beginning Operation in Year y in EMM region r and Fuel Region R at Short-Term Supply Step E (Gigawatts); and

BLD'$_{yrRcE}$ = Adjusted LP Build Decision for Capacity Type c Beginning Operation in Year y in EMM region r and Fuel Region R at Supply Step E (Gigawatts).

The market sharing routine can be done over all technologies, any subset of technologies, or for multiple groupings of technologies. For AEO2025, the market sharing loops over three distinct groups: intermediate and baseload generators, peaking capacity (combustion turbine and battery storage) and intermittent technologies. This prevents sharing across technologies that provide very different generation patterns or contribution to reserve margin.

Demand expectations

EMM can determine demand expectations using an alternative method to the original approach used by the Integrating Module.[28] This methodology relies on a smoothing technique to limit the impact of extreme changes in demand that could occur in a given year. This procedure is described below:

$$(3\text{-}90) \quad \mathbf{GDEM_{sry} = DEM - WGHT_{sr} * GDEM_{sr(y\text{-}1)} + (1 - DEM\_WGHT_{sr}) * DEM\_GRW_{sr}}$$

where

GDEM$_{sry}$ = expected annual growth rate for electricity demand in sector s in region r in year y (scalar);

DEM_WGHT$_s$ = weighting factor used to smooth original and new expected demand growth rate (scalar);

GDEM$_{sr(y-1)}$ = previous expected annual growth rate for electricity demand in sector s in region r in previous year y-1 (scalar); and

DEM_GRW$_{sr}$ = initial expected demand growth rate (scalar).

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[28] For more information on the methodology to determine adaptive expectations, see U.S. Energy Information Administration, *Integrating Module - NEMS Documentation*, DOE/EIA-M057 (2025) (Washington, DC, April 2018), DOE/EIA-M057 (2025) (Washington, DC, August 2025).

Appendix 3.A. Electricity Capacity Planning Data Flows

For AEO2025, ECP uses the Advanced Interactive Multidimensional Modeling System (AIMMS) software to create and store coefficients in a database, solve the problem, and send the solution back to the EMM. Some aspects of the coefficient calculations are still performed in the EMM Fortran code (uecp.f) but the majority of the calculations are in the AIMMS code. The post-processing of the LP solution also remains in Fortran for AEO2025. The routines described here remain in the Fortran code (uecp.f), but any coefficient calculations are ultimately derived in the ecp.ams project, and future updates will only be made within AIMMS.

The subroutine *ELECP* initializes variables and calls *ECP_LP*, which controls the setup and solution of the LP model. *REVECP* first calls the AIMMS project, REStore (Appendix 3.D.), to determine inputs related to the value of building battery storage and the detailed operation of battery and intermittent generation. REVECP then executes a series of Fortran subroutines, however as noted above these are no longer directly used to calculate revisions of coefficients for the Electricity Capacity Planning (ECP). The modified coefficients include costs in the objective function, constraint matrix (row/column intersections and right-hand sides), and bounds (lower and upper limits) on decision variables. Flags are available that can pass Fortran calculated coefficients to AIMMS, or the model can use coefficients calculated in AIMMS. Necessary data is sent to AIMMS through a text file, and AIMMS is launched do calculations and solve the LP model. The solution is passed to Fortran through a text file, and parsed back into the typical ECP coefficient structure so that the output routines can populate NEMS variables with the solution.

Matrix revisions

EP$ALLOW sets up the right-hand side of the emissions constraints for each year of the planning horizon. For sulfur dioxide (SO_2), the right-hand side represents the limit corresponding to the sum of the emissions allowances allocated in accordance with the Clean Air Act Amendments of 1990 (CAAA1990) or other proposed limits. Restrictions on SO_2 emissions are implemented as national constraints because allowances can be traded. *EP$ALLOW* calls *GETSO2*, which is a data processing routine that obtains the SO_2 allowances from an EMM input file. *EP$ALLOW* similarly represents limits on nitrogen oxides (NO_X) and mercury (Hg) emissions.

EP$CARLM sets up regional carbon limits, if specified. *CTS* determines carbon transport and storage costs for plants with CCS equipment.

EP$ST_RPS sets up the state RPS programs.

EP$ETT imposes interregional transmission constraints. *EP$ETT* calls *GETEIJ*, which is a data processing routine that obtains transmission and trade data from an EMM input file.

EP$ELAST sets up capacity supply curves that represent infrastructure limits, which can affect the amount of capacity that can be built in the near term. *EP$BLDLIM* represents regional or national limits on new plants because of limited sites or other conditions.

EP$CSUPPLY creates the coal supply curves that are used to represent the delivery of coal to electric-generating plants. It uses information from the Coal Market Module (CMM) to describe production and transportation costs, available supplies, and coal characteristics such as Btu content and emissions rates for SO_2, NO_X, Hg, and CO_2. This subroutine also sets up the decision variables to retrofit and operate coal-fired capacity to cofire with biomass. These decisions can reduce emissions or contribute to the requirements specified in a renewable portfolio standard, or both. *EP$CSUPPLY* also calls *COMBINE_COAL_RATES*, which combines domestic and international coal transportation rates into a combined cost structure.

EP$COAL creates the model structure for retirement and retrofit decisions for existing coal capacity. It represents the costs of retiring plants, plants continuing to operate in their present configurations, and plants installing control devices to reduce emissions of SO_2, NO_X, CO_2, and Hg (including scrubbers, low-NO_X burners, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), spray dryers, carbon capture and sequestration (CCS), and fabric filters).

EP$NGBS creates the model structure for retirement and retrofit decisions for non-peaking natural gas-fired plants. It represents the costs of retiring, continuing to operate in the current configuration or retrofitting with CCS.

EP$FLCRV sets up supply curves for natural gas and oil using the expected prices for quantities above and below the initial starting point.

EP$CF sets up rows to accumulate capacity and generation by plant type to compute utilization rates. *EP$CFMIN* provides the option to impose minimum generation levels for biomass cofiring.

For each of the electricity supply regions, the data processing routine *GETBLD* reads a file that stores input data required to generate coefficients in the LP model. The following routines are called from within a loop over the regions.

EP$RET sets up a national-level constraint that represents infrastructure limits on the amount of scrubber retrofits that can be completed annually. This limit is relaxed over time as additional retrofits are required.

EP$BLD sets limits for distributed generation builds (within the power sector) to an assumed percentage of peak demand growth.

EPPMLF determines the planned maintenance and load-following requirements. The planned maintenance constraints ensure that capacity is removed from service to perform annual maintenance. The load-following calculation is no longer used, as the operating modes introduced for spinning reserves incorporate this behavior.

EP$MRM computes the total capacity needed to meet the reserve margin requirement. *EP$MRM* determines minimum capacity for insuring reliable supplies, based on the input reserve margin target. *EP$LOAD* establishes the required allocation of capacity to meet the demand for electric power in each seasonal/time-of-day load segment in the ECP. The calculations in *EP$MRM* and *EP$LOAD* represent the

respective right-hand sides of the reserve margin rows and electricity load requirement rows in the LP model. *EP$MRM* also sets up the spinning reserve constraints by region, season and slice.

EP$RPS sets up the constraints that represent renewable portfolio standards (RPS), which impose a minimum generation requirement for qualifying renewable technologies. This subroutine also can specify a maximum credit price that can be incurred if the cost of building additional renewable capacity becomes too expensive.

EP$LINT imposes a limit on the amount of generation that can be provided by intermittent capacity (in other words, wind and solar). This constraint represents reliability concerns that can result if too much of the available supply is provided by technologies with energy sources that vary hourly or seasonally.

EP$RFS creates fuel supply curves to represent the costs and quantities of biomass fuel. This fuel is used in dedicated biomass plants and coal capacity that cofires with biomass.

The remaining revisions primarily involve updating coefficients for the decision variables in the ECP. These coefficients describe cost and performance characteristics for building and operating fossil fuel, nuclear, and renewable technologies. The primary function of *EP$BDSP* is to calculate the objective function coefficient for decision variables to build new fossil fuel and nuclear units (referred to as build vectors). This coefficient corresponds to the discounted present value of construction expenditures and fixed operations and maintenance costs for building new generating capacity and the associated transmission equipment. *EP$BRNW* updates the corresponding objective function value for new renewable capacity (for example, geothermal, hydroelectric, biomass), excluding intermittent technologies (for example, wind and solar). For some renewable technologies, the Energy Policy Act of 1992 (EPACT) established cost credits, which are subtracted from the corresponding capital costs. *EP$BRNW* also imposes limits (upper bounds) on capacity additions for renewable technologies because of resource constraints, if appropriate. *EP$BDGN* determines the objective function coefficients and maximum capacity additions for each step of the distributed generation supply curves.

EP$ODSP modifies the coefficients for decision variables that describe the allocation of fossil fuel and nuclear capacity to meet the demand for electricity (referred to as operate vectors). This process determines the cost of operating fossil fuel and nuclear capacity types, based on the discounted present value of operating expenses (fuel and variable operating and maintenance costs). These capacity types are considered dispatchable because they are generally available to generate electricity except for planned and unplanned outages. One of the decisions evaluated by the ECP is the mode of operation for these capacity types, which ranges from baseload (continuous operation except for outages) to peaking (operated only during periods when demand is high). The total variable cost depends on the utilization rate and the per-unit operating costs. *EP$ODSP* calls *EPDRATE*, which calculates the derating factors for dispatchable capacity types across all load slices. The derating factor is a function of the forced outage rate, planned maintenance rate, and load-following rate of the capacity type and of the load shape.

EP$ORNW is similar to *EP$ODSP*, except it determines the operating cost and performance coefficients for renewable capacity types, excluding intermittent technologies. If appropriate, the variable costs for renewable technologies are reduced to account for subsidies specified in EPACT. The renewable capacity types described in *EP$ORNW* are similar to fossil fuel and nuclear units in that they are generally

dispatchable, but they may be subject to an energy constraint (for example, steam for geothermal and water for hydroelectric) that imposes a maximum utilization rate.

EP$INT revises the cost and performance coefficients for intermittent technologies. Unlike the dispatchable capacity types, which have separate decision variables for the construction and operation of capacity, a single variable is used for intermittent technologies. ECP essentially determines whether or not to build these capacity types because they will be operated if available because they have relatively low operating costs. However, the utilization of these technologies varies according to the season and time-of-day depending on the availability of the resource (for example, sun and wind). The objective function coefficient is the present value of building and operating intermittent technologies. As with the other renewable technologies, the capital and operating costs are decreased to reflect subsidies from EPACT. The coefficients in the constraint matrix describe the variations in utilization rates across the seasonal and time-of-day load segments.

The subroutines that calculate the costs of building new capacity (EP$BDSP, EP$BRNW, EP$BDGN, and EP$INT) call a couple of subroutines that determine costs associated with new plant construction. *EPINCST* computes the installed cost of new capacity, accounting for construction expenditures, interest, and inflation, while also providing the tax basis and book value for a unit of each technology type. EPCNBLD then determines the corresponding annual capital recovery payment.

EP$NUC creates the decision variables to represent retirements of existing nuclear capacity. These variables determine whether it is economical to continue operating existing plants as opposed to retiring them and replacing them with other types of capacity.

Solution retrievals

The solution file from AIMMS is read in by Fortran code, and the calls to the output routines made in ECP_LP below continue to be used to populate variables for the other EMM or NEMS submodules.

EPO$BANK retrieves and stores the allowances banked in the current year. The banked allowances are provided to the Electricity Fuel Dispatching (EFD) Submodule so that the emissions limit for the current projection year can be increased by the corresponding amount. *EPO$RPS* obtains the dual values of the renewable portfolio standard constraints, if any, and computes the levelized credit price. *EPO$RPSR* serves the same purpose for regional RPS programs along with EPO$ST_RPS for the state RPS programs.

EPO$CARLM retrieves the emissions levels and dual (marginal) compliance costs associated with regional carbon limits. EPO$CCAP retrieves the duals on the carbon capture constraint to be used in the levelized cost calculations.

For intermittent renewables, *EPO$INT* computes the corresponding share of generation, which forms the basis for future limits.

 EPO$TBLD identifies national-level build limits to ensure that these restrictions are not violated when the capacity decisions are reallocated by the market-sharing algorithm. *EPO$ETT* captures the decision

to build new interregional transmission capacity and updates the appropriate regional transmission capacity limits.

EPO$COAL obtains the planning decisions to retire existing coal capacity or retrofit plants with pollution control devices. *EPO$NGBS* stores retirement and retrofit decisions for non-peak natural gas-fired capacity. *EPO$NUC* stores retirement decisions for existing nuclear capacity.

Before getting the remaining planning decisions, the data processing routine *GETBLD* retrieves input data such as capital costs and the cost of capital to calculate the required expenditures. For each electricity supply region, *EPO$AVOID* obtains the avoided cost of electricity (the cost of producing an additional unit of electricity). This value is determined so that RFM can construct supply curves for selected technologies.

EPO$BILD retrieves capacity expansion decisions and provides them to EFD to adjust the available capacity for future dispatching decisions. *EPO$BILD* also provides investment costs for new capacity to the EFP submodule to include in the revenue requirements. *EPO$BILD* also stores the retirement decisions for non-coal fossil capacity. *EPO$ELAST* identifies technologies with capacity additions that are limited by the infrastructure constraints.

EPO$PM and *EPO$COF* capture the planned maintenance and cofiring decisions from ECP, respectively. These results can be passed to the EFD if this option is specified by the user. The information from the LP solution is made available to the other submodules using *STRBOUT* and *STRPCNTL*, which store the data on direct access files.

EPO$CF obtains the generation and capacity results from accounting rows and determines the resulting capacity factors. *EPO$GENFL* stores the generation by region and fuel type.

EPO$FLCRV derives the projected fuel costs, which are used in *EP$LVAR* to determine the levelized variable costs by technology. *EP$LRPT* writes out the levelized operating and capital costs.

RNWRPT summarizes the cost and performance assumptions for renewable technologies. *FOSRPT* and *DGNRPT* provide the corresponding information for fossil fuel and distributed generation options, respectively.

Appendix 3.B. Data Sources

This appendix provides a list of the data sources in the Electricity Capacity Planning (ECP). Each data source is accompanied by a brief description.

Survey forms

Form EIA-860, Annual Electric Generator Report

The Form EIA-860 collects data on the status of existing electric-generating plants and associated equipment (including generators, boilers, cooling systems, and flue gas desulfurization systems) in the United States and those scheduled for initial commercial operation within 10 years of the reporting period. The data are disseminated in various EIA information products. The data are used by public and private analysts to monitor the current status and trends in the electric power industry and to evaluate the future of the industry. Form EIA-860 is completed for all electric-generating plants, which have or will have a nameplate rating of 1 megawatt (1,000 kilowatt) or more and are operating or plan to be operating within 10 years of the reporting period.

Form EIA-860M, Monthly Update to the Annual Electric Generator Report

Form EIA-860M covers the same respondents as the annual report and collects data on the status of proposed new generators scheduled to begin commercial operation within the next 12 months, existing generators scheduled to retire in the next 12 months, and existing generators that have proposed modifications scheduled for completion within 1 month.

Form EIA-861, Annual Electric Power Industry Report

Form EIA-861 collects information on the status of electric power industry participants involved in the generation, transmission, and distribution of electric energy in the United States, its territories, and Puerto Rico. The data are used to accurately maintain the EIA frame of electric utilities, to draw samples for other electric power surveys, and to provide input for various EIA information products. The data collected are used to monitor the current status and trends of the electric power industry and to evaluate the future of the industry. Form EIA-861 is completed by electric industry participants including electric utilities, wholesale power marketers (registered with the Federal Energy Regulatory Commission), energy service providers (registered with the states), and electric power producers.

Form EIA-923, Power Plant Operations Report

Form EIA-923 collects information from electric power plants and combined-heat-and-power (CHP) plants in the United States. Data collected on this form include electric power generation, fuel consumption, fossil fuel stocks, delivered fossil fuel costs, combustion byproducts, operational cooling water data, and operational data for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter control equipment. These data are used to monitor the status and trends of the electric power industry and appear in many EIA publications. Form EIA-923 is completed by all electric power plants and CHP plants that have a total generator nameplate capacity of 1 megawatt or greater.

FERC Form 1, Annual Report of Major Electric Utility

FERC Form 1 is a mandatory annual census of major investor-owned electric utilities that meet specified criteria for sales. The form collects data on income and earnings, taxes, depreciation and amortization, salaries and wages, operating revenues, and operating and maintenance costs.

Quality of EIA Survey Data

The Assistant Administrator for Energy Statistics oversees routine data improvements and quality assurance activities of EIA survey data. Data improvement efforts include verification of input data by automatic computerized methods, editing by subject matter specialists, and follow-up on nonrespondents. Manual edit checks include spot checking information against the survey forms. Computer edits include both deterministic checks, in which records are checked for the presence of required fields and their validity, and statistical checks, in which estimation techniques are used to validate data according to past behavior and in comparison to other current fields. Data values that fall outside of prescribed ranges are verified by contacting respondents to resolve any discrepancies.

U.S. Environmental Protection Agency (EPA) *Emissions Characteristics and Costs*

- Allowance Management System (AMS)—database for SO_2 allowances under the Acid Rain Program specified by the Clean Air Act, recorded on the EPA Air Markets Program Data homepage
- NO_X Allowance Management System—data on NO_X allowances under the NO_X Budget Program is also recorded on the EPA Air Markets Program Data homepage
- IPM Model—Revisions to Cost and Performance for APC Technologies, prepared by Sargent & Lundy (Chicago, IL, August 2010)
- *Documentation for the 2023 Reference case -* EPA's Power Sector Modeling Platform 2023 Using IPM, April 2024 – costs for coal to gas conversion

Distributed Utility Associates *Cost and Performance Characteristics for Distributed Generation*

- Assessing Market Acceptance and Penetration for Distributed Generation in the United States (June 1999).

National Renewable Energy Laboratory

Regional Energy Deployment System (ReEDS) Model

ReEDS is a capacity planning and dispatch model for the U.S. electricity system and the source code and inputs are publicly available. EIA uses the ReEDS input data on transmission capacity to develop the interregional transmission capacity assumptions in the EMM.

National Energy Technology Laboratory

- Carbon Capture Retrofit Studies, March 2023

Appendix 3.C. Cost of Capital

Introduction

This document describes the assumptions, methodology, and estimating techniques used to calculate the discount rate for capital budgeting in the Electricity Capacity Planning (ECP) Submodule of the National Energy Modeling System (NEMS).

The expected construction of new electric power plants is needed to prepare the 30-year projections of energy production, consumption, and prices. Identifying the specific generating technologies that will be chosen and the fuels that they will use is part of this effort. ECP chooses the mix of plants that will minimize the total system costs of meeting consumers' electricity needs. The model performs a discounted cash flow analysis of the costs of building and operating power plants over 30 years and chooses the least-cost mix of options. ECP uses the after-tax weighted average cost of capital (WACC)[29] to discount future cash flows in the capacity expansion analysis. The discount rate is a very important component of investment decisions because the rate reflects the riskiness of the investment and affects the mix of capacity additions. Small changes in the weighted average cost of capital (WACC) can lead to relatively large changes in capital-intensive capacity additions.

Each year, the assumptions and parameters for the WACC are reviewed to reflect the changing nature of the power industry and to incorporate new capital market information. For the *Annual Energy Outlook 2025* (AEO2025), the capital structure (shares of debt and equity in the total capital invested) is assumed to be 60% debt and 40% equity for all technologies.

This appendix explains the models, assumptions, and parameters for the WACC. The following section describes theoretical approaches, assumptions, and parameters of the model. The subsequent section provides the model structure and computations.

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[29] Projects are assumed to be financed by both debt and equity and to return the expected interest payments to creditors and the expected dividends to shareholders. Therefore, the after-tax weighted average cost of capital is an appropriate discount rate for evaluating investment opportunities.

Discount rate assumptions and parameters

Investment assumptions in the ECP

In the ECP, a traditional net present value (NPV) capital budgeting methodology is employed to compare different investment options. To do so, the following assumptions are made:

- The power-generating industry is competitive. Thus, investments for power plants are assumed to be made in a competitive environment that takes into account certain risks, as opposed to the conditions experienced in a rate base or regulated environment. [30]
- Different generating technologies have the same risk treatment in investment for capital budgeting purposes. That is, the required rate of return on investment is the same for all projects, except for certain fossil-fired generator units without carbon capture and sequestration (discussed later in this appendix).
- The discount rate is different for each year[31] and is shown in Figure 8, using the 60% debt/40% equity capital structure.

Figure 8. Derived nominal weighted average cost of capital (WACC)
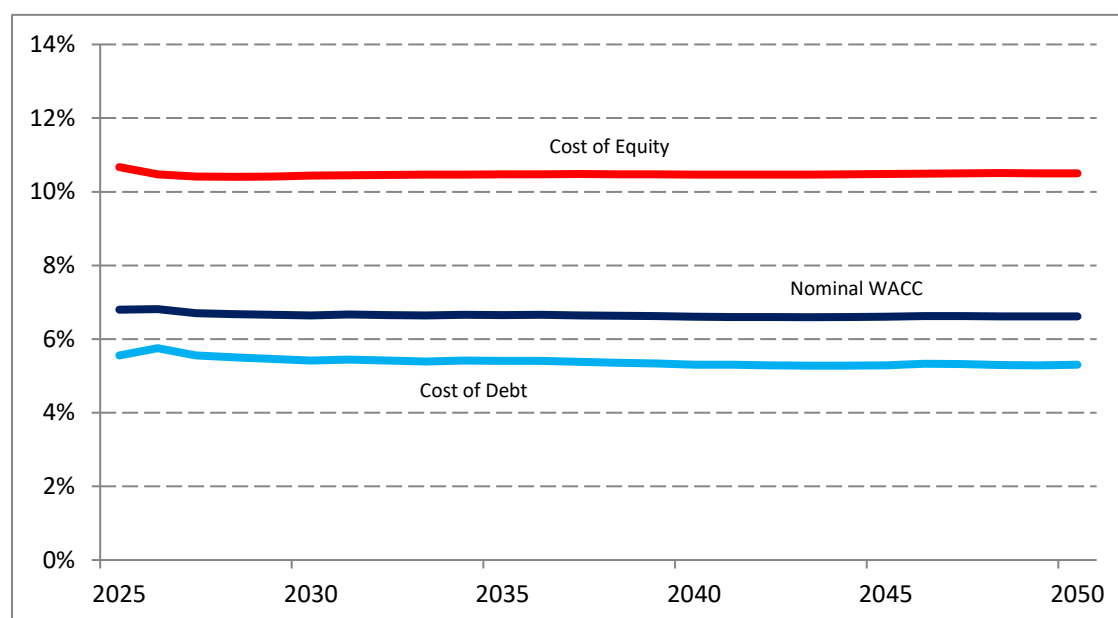
Source: *Annual Energy Outlook 2022*, NEMS Run ref2022.d011222a.

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[30] This assumption leads to a higher discount rate than a rate base environment in general. In the rate base environment, a firm is able to recapture all investment costs and receive allowed reasonable returns for the plant investment; however, the investments must account for uncertainties (risk components) in the competitive environment where the authorized guarantee returns are no longer viable.

[31] Using a fixed discount rate for the NPV methodology over the life of the project for capital budgeting is a simplified computation and overly restrictive. Because several parameters for the cost of debt and equity in NEMS are endogenously determined, the different WACC for each is derived within NEMS and is used for capital budgeting. This approach is more realistic for projecting over a 30-year period.

The WACC Overview

The WACC equation is as follows:

$$WACC = \left(\frac{Debt}{TotalCapital}\right)k_d(1-t) + \left(\frac{Equity}{TotalCapital}\right)k_s$$

$$= (w_d)(k_d)(1-t) + (w_s)(k_s)$$

where

> w_d = Debt fraction of total capital invested;
>
> w_s = Equity fraction of total capital invested;
>
> k_d = Cost of debt;
>
> k_s = Cost of equity; and
>
> t = Corporate tax rate.

To calculate the discount rate for capital budgeting, at least six different parameters—two endogenous[32] and four exogenous—need to be identified as inputs. The fundamental assumptions and parameters of the variables are shown in Table 7.

Table 7. Financial parameters and assumptions

	Variables		Parameters	
1.	Debt fraction	60%	Exogenous	Fixed
	Cost of debt:		Endogenous	Varied
2.	Industrial Baa bond rate		Endogenous	Varied
	Cost of equity: Capital asset pricing model		Endogenous	Varied
3.	Risk-free rate: 10-year Treasury note rate		Endogenous	Varied
4.	Market risk premium	5.75%	Exogenous	Fixed
5.	Equity beta	1.25	Exogenous	Fixed
6.	Corporate tax rates[33]	24%	Exogenous	Fixed
	Nominal weighted average cost of capital (WACC)		Endogenous	Varied

Assumptions and derivations of the parameters

Capital structure: Debt and equity proportions to total capital

The decision about capital structure to fund an investment project is based on the expected financial health of the industry and capital market information. For example, an investment in an industry with a healthy outlook could use a larger debt proportion for the investment, while a riskier investment project

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[32] These parameters, industrial Baa bond rate and 10-year Treasury note rate, are forecasts and are developed by the Macroeconomic Activity Module in NEMS.

[33] The corporate tax rate reflects the passage of the Tax Cuts and Jobs Act of 2017.

would require more equity relative to total capital. The capital structure for a given project will be constant over the project life.

During AEO2018, EIA commissioned an external consultant to examine the impact of various financing structures and market conditions on the WACC related to investments in new generating capacity. Using EIA data on corporate ownership of specific power plants representing both conventional and renewable technologies, along with publicly available data on corporate financial structure (including corporate debt and estimated corporate investment returns) for regulated utilities and independent power producers (IPPs), the analysis characterizes the cost of equity, cost of debt, the capital structure, and the effective average tax rate for different classes of investors. These factors are then used to compare to WACC assumptions used in the previous *Annual Energy Outlook*s. The results from the analysis show that the related values used in NEMS are close in magnitude to those based on the most recent research, although it suggests a debt fraction of 60% is more commonly observed with recent project financing. This study also indicated that technologies receiving Federal tax credits – such as the wind PTC or solar ITC – tend to have a higher equity share to maximize the capture of the tax credit, leading to the assumption of a 50% debt fraction(in earlier AEOs). The Inflation Reduction Act (IRA) of 2022 allows for transferability of the Federal tax credits, minimizing the need for tax equity partnerships, and therefore, EIA reverted back to a debt fraction of 60% for both solar PV and onshore wind technologies starting in AEO2023. It should be noted that the analysis is focused on company-level and some subsidiary-level analysis and not at project-level analyses that would give better insight on project economics that may vary by location or technology for a given company. The information needed to estimate WACC confidently on a project specific basis is usually not available outside of an individual company.

Cost of debt

Cost of debt (k_d) is interest rate on borrowed money and is determined by the industrial Baa bond rate:

$$\text{Cost of debt}_t = k_{dt} = \text{Baa bond rate}$$

where

k_{dt}	=	Cost of debt in year t
Baa bond rate$_t$	=	Industrial Baa bond rate in year t

Because the Macroeconomic Activity Module (MAM) endogenously determines the industrial Baa bond rates for the projection period, rates (cost of debt) are different for each year. An average debt rating for a utility project is assumed to be Baa. To apply a firm's overall cost of debt to a new power plant investment within the firm would be less accurate because utility firms are diversified and integrated, for example, in providing generation, transmission, or distribution of electric energy for sales. Thus, a discount rate for the expected construction of new electric power plants should be adjusted upward given our assumption of higher risk relative to other investments (transmission and distribution).

Cost of equity

The Capital Asset Pricing Model (CAPM) was used to compute a cost of equity, which is an implied investor's opportunity cost (in other words, the required rate of return of any risky investment). The model is:

$$k_{st} \quad = \quad k_{RFt} + (EMRP)\beta_{Equity}$$

where

k_{st} = Cost of equity at year t;

k_{RFt} = Risk-free rate at year t;

EMRP = Expected market risk premium (constant); and

β_{Equity} = Equity beta (constant).

Risk-free rates (k_{RF}) are based on 10-year Treasury note rates to reflect the same one-time investment horizon for all investors. The future spot 10-year Treasury note rates in the MAM are used as estimates of expected risk-free rates in future time periods.

The expected market risk premium (EMRP) is the expected return on market (S&P 500) over the rate of 10-year Treasury note (risk-free rate). A number of studies have estimated the expected equity risk premium by using a variety of approaches. These studies can be categorized into four groups based on the approach and methodology. The first group of studies derives the equity risk premium from the historical returns between stocks and bonds. The second group uses supply-side models, incorporating fundamental information such as earnings, dividends, or overall productivity. A third group adopts demand-side models that derive the expected return of equity based on the payoff required by equity investors for bearing the additional risk. The opinions of financial professionals and industry practitioners based on a survey are used by the fourth group.[34] EIA's approach estimates the expected market risk premium using the historical market risk premium methodology with arithmetic mean[35] of expected returns on both S&P 500 and government bonds, which are estimated by a Monte Carlo simulation. EIA assumes the EMRP to be 5.75%.

The industry composite equity beta for the electric utility industry is determined by a pure play analysis of large capital intensive industries, such as transportation, communication, and electricity, and is assumed to be 1.25. Because the electric utility industry has undergone restructuring in recent years, historical electric utility data are not useful to analyze statistical inferences, especially going forward; therefore, the structure and size of the benchmark industry is an appropriate guide to the current and future electric utility industries. Under regulated electric utility regimes, both equity and debt investment returns are guaranteed by a cost recovery system over time. Thus, the risk for equity or debt holders is the same. However, the investment risk for equity holders is greater than that of debt holders under unregulated electric utility regimes because the power producer faces more uncertain outcomes as a result of input factors and output prices as well as returns.

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[34] Fernandez, P., J. Aguirreamalloa and L. Corres (2013), "Market Risk Premium and Risk Free Rate used for 51 countries in 2013: a survey with 6,237 answers."

[35] The arithmetic mean is used to estimate historical returns instead of the geometric mean, which is backward-looking and measures the change in value over more than one period. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending values, which makes the arithmetic mean return appropriate for forecasting the cost of capital.

As a result, the risk and return assessment must be estimated for the equity holders.[36] Because equity holders now face not only business risk but also financial risk, the cost of equity should include financial risk premium.[37]

We proceed by not only obtaining betas for similar publicly traded firms to get an industry composite beta (pure play) but also obtaining an asset beta for the utility industry and then adjusting it up or down to make it consistent with the project or target firm's risk level, capital structure, and tax rate. The result is an estimate of the target industry's beta, given (1) its business risk as measured by the asset beta of the business and (2) its financial risk as measured by its own capital structure and tax rate.

In addition to the benchmark industry equity beta, the utility industry composite equity beta is computed using the Hamada model, which combines the CAPM with the Modigliani-Miller (MM) after-tax model to obtain the cost of equity to a leveraged firm.[38] This model captures not only business risk but also financial risk for equity holders.

Adjustment for greenhouse gas-intensive technologies

There continues to be much debate and uncertainty surrounding the potential for climate change legislation and how much it is affecting the decision-making of new power plants. Banks and regulators are appearing to add implicit costs to greenhouse gas (GHG)-intensive technologies when evaluating new investment opportunities. This trend is modeled through an increase in the cost of capital for new coal capacity through a 3-percentage-point adder applied to both the cost of debt and cost of equity described in this section. This adjustment should be seen not as an increase in the actual cost of financing but rather as representing the implicit costs being added to GHG-intensive projects to account for the possibility that, eventually, they may have to purchase allowances or invest in other projects that offset their emissions. The adjustment is applied to the cost of capital for new coal-fired plants with 30% carbon capture and sequestration (CCS) because they would still be considered high emitters relative to other new sources and thus may continue to face potential financial risk if carbon emission controls are further strengthened.[39] AEO2025 extends the adder to NGCC plants as more state and federal incentives are put in place to encourage low- or zero-carbon emitting technologies, making building new natural gas-fired plants subject to increased risk of changing policies that could shorten their effective cost recovery period. The adder is not applied to simple-cycle combustion turbine plants because those plant types are most often built for reserve capacity and do not contribute as much to emissions.

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[36] In the event of bankruptcy (Chapter 11), in general, the equity holders bear all the costs and are at risk of losing all of their investment.

[37] Business risk is associated with the operating conditions faced by and the operating decisions made by a firm, while financial risk is the additional risk placed on the equity holders as a result of the decision to finance with debt.

[38] Conceptually, equity holders face a certain amount of risk that is inherent in a firm's operations even if there is no debt in its capital structure. If a firm uses debt (financial leverage), the equity holders will face more risk as a result of financial leverage. As a result, the cost of equity of a firm that has financial leverage in its capital structure (levered firm) is higher than the cost of equity of a firm that has no financial leverage (unlevered firm).

[39] New coal plants without CCS do not meet the performance standards specified in Section 111(b), so they cannot be built.

Appendix 3.D. REStore model formulation

Introduction

The REStore submodule is a cost minimization linear programming model that determines the dispatch of various generating and storage technologies based on the total cost of electricity. The REStore submodule assesses the impact of energy storage technologies on the dispatch of electricity generation in each of the EMM regions. Energy storage provides many benefits to the grid, but REStore focuses on the benefits of diurnal battery storage when planning the dispatch of generating technologies. Storage is installed to provide ancillary services and allow for arbitrage of energy from high-supply/low-demand periods to high-demand/low-supply periods, including facilitating the integration of intermittent renewables such as wind and solar into electricity markets. Short duration batteries used for services such as frequency control are not modelled in REStore. The type of energy storage can vary in material, process, and length depending on the application; however, in REStore, battery storage is defined by the power capacity and energy capacity parameters.

REStore models two energy storage technology categories: *pumped storage* and *storage*. Storage may include many types of energy storage technologies, which vary in many characteristics, such as lithium-ion batteries, flow batteries, lead-acid batteries, and flywheels. Because the majority of installed energy storage excluding pumped hydro storage is lithium-ion batteries, most of the parameters such as battery efficiency, cost, and duration that define the storage technology in REStore are based on lithium-ion batteries.

REStore provides input to the Electricity Fuels Dispatch Submodule (EFD) on the operation of currently installed storage capacity, as well as to the Electricity Capacity Planning Submodule (ECP) on the marginal value to the system of building a new increment of storage.

Model purpose

The purpose of the REStore model is to efficiently dispatch electricity from various generating technologies with a given capacity of storage. The decision-making in the model determines what time of day the storage should charge and discharge by minimizing the costs of generation and penalties from unmet load. REStore makes its decisions based on a least-cost optimization. Curtailments can result in low electricity prices. When electricity generation from intermittent sources such as solar and wind is greater than the load, the excess supply must be stored or lost. On the other hand, unmet load can result in high electricity prices because generation could not meet the load demanded, which is modeled with an unmet load penalty.

Key quantities determined in the model are generation, curtailment, unmet load, storage charging and discharging, storage levels, storage available for spinning reserves, interregional trade, and marginal prices of electricity.

- Generation profile: the generation from a diverse combination of generating technologies, which will differ from region to region.

- Curtailment: the generation lost from overproducing electricity that acts as a key driver for energy storage.
- Unmet load: when generation does not meet demand, a loss of profit and possible penalty occurs as a result of customers not receiving electricity. Note that this output is not used in EMM, only for debugging purposes.
- Storage charging and discharging: a decision made by the model of when to charge and discharge storage based on the overall lowest system cost.
- Storage levels: the state-of-charge of storage, which specifies how much of the battery energy capacity is available to be discharged.
- Storage available for spinning reserves: this is a post-processing step which calculates the fraction of storage capacity available to procure spinning reserves based on storage behavior.
- Interregional trade: the amount of energy traded between regions. Note that this output is not used in EMM, only for debugging purposes.
- Marginal price of electricity for each time period: the cost of electricity, which is affected by the region's load and generation profile. The cost of electricity will be higher during periods where higher cost technologies are dispatched and lower when only low cost technologies are generating, such as wind and solar.

Typically, the charging and discharging pattern of storage correlates with the marginal price because the model dispatches generation economically. For regions with high solar penetration, for example, storage charging generally occurs in the afternoon when there is high solar, while storage discharging generally occurs in the evenings when load is high and the sun has set. Discharging generally happens when the marginal price is high because of high net load.

The REStore model evaluates the role of storage in the power grid and this information is used in EMM to decide whether the cost of building and maintaining a storage unit is worth the services that it provides for energy arbitrage, meeting capacity reliability reserve margins, and providing operating reserves. There are many other ancillary services, such as frequency control, ramping support, and demand response that the EMM module does not include, and are also not included in REStore. Although operating (spinning) reserves are not modeled in REStore, this model calculates the fraction of available battery storage capacity for the procurement of spinning reserves by technology, region, solve index, and EMM time slice to pass to EMM; taking the maximum possible battery discharge that is not used for meeting load. This fraction of capacity available to procure spinning reserves is used in both ECP and EFD.

The Hydrogen Market Module (HMM) uses several hourly data outputs from the REStore model in its calculation of hydrogen pricing and electrolyzer operation. These include the hourly marginal prices of electricity, curtailment, renewable generation, and hourly available electricity (delta between total available hourly electricity supply and generation).

Model formulation

The REStore model relies on the inputs from various submodules in EMM and supply modules in NEMS. EMM compiles the inputs to the REStore model in a text file named ecpout with the year that is being solved, so the model only solves for one year at a time, but runs each year. An input text file named

restprep contains parameters that can be changed through analyst judgement. Storage and intermittent curtailments are the main focuses of the model. A fixed storage capacity is given for each year by EMM. REStore decides how much of the current storage capacity is used and the maximum additional storage capacity that can be built in EMM. The EMM submodule feed REStore the current storage capacity and a marginal addition of storage builds for each year, then REStore solves both cases. Finally, REStore reports the generation of each technology, curtailment of each technology, storage charging and discharging, storage level, marginal prices, storage available for spinning reserves, interregional trade, and unmet load.

The Model Objective Function

The model solves a linear programming objective function that minimizes the total cost of generation, storage, and trade, which also includes the ramping capability of conventional generation technologies. Note that this objective function has units of thousands of dollars.

(App3.D-1)

$$minimize \sum_{hr,reg} DayWeights_{hr}$$

$$* \left(\sum_{ptpvb,y,step} \left(StorageInflow_{ptpvb,y,reg,step,hr} + StorageOutflow_{ptpvb,y,reg,step,hr} \right. \right.$$

$$\left. * \sum_{s|hr=map(s)} SupplyPrice_{reg,s,ptpvb,y,step} \right)$$

$$+ \sum_{ptny,step} \left(\frac{1}{2} * \left(StorageInflow_{ptn,y,reg,step,hr} + StorageOutflow_{ptn,y,reg,step,hr} \right) * \sum_{s|hr=map(s)} SupplyPrice_{reg,s,ptn,y,steps} \right)$$

$$+ \sum_{pts,y,step} \left(StorageLevelCost * StorageLevel_{pts,y,reg,step,hr} \right)$$

$$+ \sum_{ptc,y,step} \left(Generation_{ptc,y,reg,step,hr} * \sum_{s|hr=map(s)} SupplyPrice_{reg,s,ptc,y,step} \right)$$

$$+ \sum_{ptr,y,step} \left(Generation_{ptr,y,reg,step,hr} * \sum_{s|hr=map(s)} SupplyPrice_{reg,s,ptr,y,step} \right)$$

$$+ \sum_{pti,y,step} \left(Generation_{pti,y,reg,step,hr} * \sum_{s|hr=map(s)} SupplyPrice_{reg,s,pti,y,step} \right)$$

$$+ \sum_{ptc,y,step} \left(RampUpCost_{ptc} * RampUp_{ptc,y,reg,step,hr} + RampDownCost_{ptc} * RampDown_{ptc,y,reg,step,hr} \right)$$

$$+ \sum_{y,rsub} \left(TradeToFrom_{reg,rsub,y,hr} * TranCost_{reg,rsub,y,1} \right)$$

$$+ \sum_{y,rcan,csteps} \left(TradeToFromCan_{reg,rcan,y,hr,csteps} * TranCost_{reg,rcan,y,csteps} \right)$$

$$+ \sum_{y} \left(UnmetLoad_{reg,y,hr} * UnmetLoadPenalty \right) \Bigg)$$

Definition of indices:

$hr = ecp\ hour\ (1 \ldots 24)$

$y = year$

$s = season\ (summer, winter, fall/spring)$

$reg = domestic\ EMM\ region$

$rsub = domestic\ NEMS\ region(duplicate\ indicies)$

$rcan = Canadian\ NEMS\ region$

$csteps = Canadian\ trade\ supply\ step$

$step = supply\ step$

$pts = storage\ (including\ PV\ hybrid)\ technology\ group$

$ptn = storage\ (excluding\ PV\ hybrid)\ technology\ group$

$ptpvb = PV\ hybrid\ technology\ group$

$ptc = conventional\ technology\ group$

$ptr = renewable\ technology\ group$

$ptipv = intermittent\ (including\ PV\ hybrid)\ renewable\ technology\ group$

The objective function defined above includes the costs of each technology group, which are first mapped from the ECP plant types, then mapped again into four general groups: storage, conventional, renewable, and intermittent. The storage portion of the objective function is the sum of costs from charging, discharging, and maintaining the storage level. This cost is known as the variable cost of storage. It is assumed that the cost is split evenly between the charging and discharging (hence the 1/2). This cost is also applied to PV battery hybrid technology, but the cost is not multiplied by ½ to avoid cycling issues. The storage level cost is to ensure that the storage technology does not store unused energy over time, that is, energy that is never discharged. The conventional portion consists of the variable generation and ramping costs. The variable generation cost of conventional, renewable, and intermittent technologies is the cost of dispatch over time. Note that the intermittent technologies have small cost values to set the dispatch order; the lowest cost will be dispatched first and with increasing intermittent variable cost, the technology will be curtailed first. REStore has the following order from lowest to highest cost: distributed PV, utility-scale PV, wind, and finally hydropower. The ramping cost of conventional generation is determined by how fast a plant can increase its power output and the cost in performing the required ramping. Ramping for conventional technology is related to the load following capability of rapidly changing loads over time. The domestic interregional trade cost includes a cost to trade electricity between two domestic regions. The Canadian trade cost includes the cost to import electricity from Canada. The unmet load penalty represents the cost of not meeting the load demand, which incurs reliability costs and loss of profit. Lastly, the summation is scaled up by multiplying by day weights.

Model constraints
The REStore submodule accounts for many constraints such as energy balance of storage, demand balance, ramping, trade, and dispatchable hydropower. The bulk of the constraints are on the energy balance of storage: efficiencies of charging and discharging and carrying state-of-charge over to the next day. The rest of the constraints are to ensure the load, trade, and generation are balanced.

(App3.D-2)

$EMMLoad_{reg,y,hr}$

$$\leq \sum_{ptc,step} Generation_{ptc,y,reg,step,hr} + \sum_{ptr,step} Generation_{ptr,y,reg,step,hr}$$

$$+ \sum_{pti,step} Generation_{pti,y,reg,step,hr}$$

$$+ \sum_{ptn,step} StorageOutflow_{ptn,y,reg,step,hr} - StorageInflow_{ptn,y,reg,step,hr}$$

$$+ \sum_{ptpvb,step} Generation_{ptpvb,y,reg,steps,hr} + StorageOutflow_{ptpvb,y,reg,step,hr}$$

$$+ \sum_{rsub} TradeToFrom_{reg,rsub,y,hr} * (1 - TransLoss) - TradeToFrom_{rsub,reg,y,hr}$$

$$+ \sum_{rcan,csteps} (TradeToFromCan_{reg,rcan,y,hr,csteps} * (1 - TransLoss))$$

$$+ UnmetLoad_{reg,y,hr}$$

Definition of Indices:

$pti = intermittent\ (excluding\ PV\ hybrid)\ renewable\ technology\ group$

The constraint above is the demand energy balance where the total generation of each technology group plus net trade imports plus the unmet load must be greater than or equal to the demand from EMM. The energy balance is used for each EMM region and every hour. Note that *StorageInflow* of the PV storage hybrid technology is not included in the energy balance constraint since that energy is from a PV unit, not the grid. REStore models its PV storage hybrid technology as a unidirectional DC-coupled system with an inverter capacity equal to the PV capacity and a 4-hour duration battery with one-third the power capacity of the inverter. Additionally, trade losses are accounted for using the parameter TransLoss, where losses are applied for the importing region.

(App3.D-3)

$CapacityFactor_{pt,y,reg,step,hr}$

$$= \sum_{m|hr=map(m),d|hr=map(d),hr|h=map(hr)} M864\_LF_{pt,step} + (1 - M864\_LF_{pt,step})$$

$$* \frac{Load_{reg,y,m,d,h}}{DailyPeakLoad_{reg,y,m,d}}$$

The capacity factors for conventional technologies are calculated through an input, M864_LF, and are calculated similarly to the method used in EMM. There are two parts in the calculation that sum to 1 if Load is equal to Daily Peak Load. The M864_LF is the base capacity factor, while the other portion is

dependent on the ratio of Load to Daily Peak Load. The closer Load is to Daily Peak Load, the capacity factor approaches 1.

(App3.D-4)

$$Generation\_Upper_{ptc,y,reg,step,hr} = \sum_{s|hr=map(s)} SupplyCurve_{reg,s,ptc,y,step} * CapacityFactor_{ptc,y,reg,step,hr}$$

$$Generation\_Upper_{ptr,y,reg,step,hr} = \sum_{s|hr=map(s)} SupplyCurve_{reg,s,ptr,y,step} * CapacityFactor_{ptr,y,reg,step,hr}$$

$$Generation\_Upper_{pth,y,reg,step=2,hr}$$
$$= \sum_{s|hr=map(s),m|hr=map(m)} SupplyCurve_{reg,s,pth,y,step=2} * HydroCapFactor_{m,reg}$$

$$Generation\_Upper_{ptipv,y,reg,step,hr}$$
$$= \sum_{s|hr=map(s),tech|ptipv=map(tech)} SupplyCurve_{reg,s,ptipv,y,step}$$
$$* SolarWindCapFactor_{reg,y,hr,tech}$$

$$Generation\_Upper_{ptn,y,reg,step,hr} = 0$$

Definition of Indices:

$pth = hydropower\ technology\ group$

$tech = EMM\ technology\ group$

The generation upper bound formulation is shown above for each technology group with a special inclusion of dispatchable hydropower, which is defined in two technology groups: renewable and hydropower. The upper bound is the maximum generation that each technology group can generate. Each generation upper bound is calculated in order, such that the dispatchable hydropower for the second step will overwrite the second step upper bound set in the renewable technology group step. Dispatchable hydropower plants are able to provide instantaneous generation; however, there is a limited amount of total energy that they can provide each month for each region; there is another constraint that limits the amount of generation that dispatchable hydropower can produce every month. The maximum generation of each technology group is calculated using capacity factors: parameters input from the EMM submodules. The supply curve represents the amount of capacity available at a given cost of generation from the EMM submodules. Technologies that are conventional usually have three steps, where cost increases as more capacity is added, but other technologies may have fewer steps. Note that the PV technology has two steps, the first for utility PV and the second for distributed PV. The final constraint sets the generation upper bound for non-PV storage technologies to zero.

(App3.D-5)

$$\sum_{hr|m=map(hr),d|hr=map(d)} Generation_{pth,y,reg,step=1,hr} * DayWeights_{m,d}$$

$$\leq \sum_{s|m=map(s)} HydroCapFactor_{m,reg} * SupplyCurve_{reg,s,pth,y,step=1} * 24$$

$$* \sum_{d} DayWeights_{m,d}$$

The constraint above is the balance of the total generation of dispatchable hydropower where the total available dispatchable hydropower for each month, scaled to its day weight, must be greater than the generation so that the model cannot overly dispatch hydropower. The amount of dispatchable hydropower available is determined by the EMM submodules that are inputs to REStore, such as the Hydro Capacity Factor and Supply Curve.

(App3.D-6)

$$RampUp\_Upper_{ptc,y,reg,step,hr} = RampDown\_Upper_{ptc,y,reg,step,hr}$$

$$= RampRate_{ptc} * \sum_{s|hr=map(s)} SupplyCurve_{reg,s,ptc,y,step}$$

The equation above sets the maximum ramping capacity available by assuming that the ramp up and ramp down rates are the same. The ramp rate is an input parameter that is percentage based and can be adjusted using analyst judgement to determine how much of the generating conventional technology can be used for ramping.

(App3.D-7)

$$Generation_{ptc,y,reg,step,hr} \text{ (excluding the first hour)}$$

$$= RampUp_{ptc,y,reg,step,hr} + RampDown_{ptc,y,reg,step,hr}$$

$$+ Generation_{pth,y,reg,step,hr-1}$$

$$Generation_{ptc,y,reg,step,hr} \text{ (including just the first hour)}$$

$$= RampUp_{ptc,y,reg,step,hr} + RampDown_{ptc,y,reg,step,hr}$$

$$+ Generation_{pth,y,reg,step,hr+23}$$

These constraints set the generation limits based on the ramping constraints for conventional technology. The first constraint sets the limit for all hours excluding the first hour and the second constraint sets the limit for the first hour of each day type and month so that the ramping balance holds and when day type loops from the last hour back to the first hour.

(App3.D-8)

$StorageLevel_{pts,y,reg,step,hr(excluding\ the\ first\ hour)}$

$$= StorageLevel_{pts,y,reg,step,hr-1} + BatteryEfficiency_{pts}$$

$$* StorageInflow_{pts,y,reg,step,hr} - StorageOutflow_{pts,y,reg,step,hr}$$

The constraint above is the energy balance of the storage level (excluding the first hour of any day), which is the sum of the previous hour storage level and the net flow of the battery. The battery efficiency is defined as the round-trip efficiency, which is a combination of the charging and discharge efficiencies and is applied to the storage inflow.

(App3.D-9)

$StorageLevel_{pts,y,reg,step,hr(only\ includes\ first\ hour)}$

$$= StorageLevel_{pts,y,reg,step,hr+23} + BatteryEfficiency_{pts}$$

$$* StorageInflow_{pts,y,reg,step,hr} - StorageOutflow_{pts,y,reg,step,hr}$$

The core assumption is that storage level from the previous hour does not carry forward to the next day type or month, meaning that the day types and months are disconnected. Instead, the storage cycles around the same month/day.

The final constraint of the storage level is the energy balance of the first hour of each day and each month where the storage level must balance with the final hour of the same day.

(App3.D-10)

$BatteryChargeCap_{ptn,reg,y,step,hr} = BatteryDischargeCap_{ptn,reg,y,step,hr}$

$$= \sum_{s|hr=map(s)} SupplyCurve_{reg,s,ptn,y,step}$$

(App3.D-11)

$BatteryChargeCap_{ptpvb,reg,y,step,hr} = BatteryDischargeCap_{ptpvb,reg,y,step,hr}$

$$= \sum_{s|hr=map(s)} \frac{SupplyCurve_{reg,s,ptpvb,y,step}}{3}$$

(App3.D-12) $StorageInflow\_Upper_{pts,y,reg,step,hr} = BatteryChargeCap_{pts,reg,y,step,hr}$

(App3.D-13) $StorageOutflow\_Upper_{pts,y,reg,step,hr} = BatteryDischargeCap_{pts,reg,y,step,hr}$

The four constraints above set the upper bound (that is, the limit) to the power of the battery for which the charge and discharge upper bounds are set by the supply curve. Constraint App3.D-10 is for non-hybrid storage types and App3.D-11 is for the PV + battery hybrid technology since we assume the battery capacity is one-third of the inverter capacity.

The supply curve is an input from the EMM submodule that determines the battery capacity available with the inclusion of the battery increments. The battery increments are additional storage builds that can be added as a second step for each region, so it can represent a secondary case where the model determines the profile of generation given more storage.

(App3.D-14)

$$StorageLevel\_Upper_{pts=diurnal,y,reg,step,hr} = HoursToBuy * \sum_{s|hr=map(s)} SupplyCurve_{reg,s,pts=diurnal,y,step}$$

The equation above represents the upper bound of diurnal storage capacity, which is based on the assumption that all diurnal storage in REStore is represented by a four-hour storage technology (notionally a lithium ion battery). Hence, the total energy capacity of storage is four times the power capacity. The hours-to-buy is an input parameter that can be changed through analytical judgement. In addition, the hours-to-sell parameter (which is not used in the model) determines the duration that storage can discharge.

(App3.D-15)

$$StorageLevel\_Upper_{pts=pumped,y,reg,step,hr} = 12 * \sum_{s|hr=map(s)} SupplyCurve_{reg,s,pts=pumped,y,step}$$

There is also a similar equation for pumped storage, except the hours-to-buy is hard coded as 12 hours.

(App3.D-16)

$$StorageLevel\_Upper_{pts=pvhybrid,y,reg,step,hr} = HoursToBuy * \sum_{s|hr=map(s)} \frac{SupplyCurve_{reg,s,pts=pvhybrid,y,step}}{3}$$

Additionally, there is a similar constraint for PV + battery hybrid with 4-hour storage, however we must also take into account that the battery capacity is one third of the system's inverter capacity.

(App3.D-17)

$$Generation_{ptpvb,y,reg,step,hr} + StorageInflow_{ptpvb,y,reg,step,hr} \leq GenerationMaxTotal_{ptpvb,y,reg,step,hr}$$

Where:

$$GenerationMaxTotal_{ptpvb,y,reg,step,hr}$$
$$= \sum_{s|hr=map(s),tech|ptpvb=map(tech)} SupplyCurve_{reg,s,ptpvb,y,step}$$
$$* (SolWindCapFactor_{reg,y,hr,tech} + ClipCapFactor_{reg,y,hr,tech})$$

The REStore model uses a unidirectional DC-coupled representation of PV + battery hybrid technology; assuming both the system's battery and PV are behind the inverter and the battery can only charge using its attached PV. PV + battery hybrid has an additional constraint in which the total PV energy to the grid and battery is limited by the availability of PV energy in that hour. One of the benefits of having a DC-coupled PV + battery system is that the battery can capture energy otherwise clipped by the PV inverter, where the amount of additional available energy is given by the parameter *ClipCapFactor*.

(App3.D-18)

$$Generation_{ptpvb,y,reg,step,hr} + StorageOutflow_{ptpvb,y,reg,step,hr} \leq \sum_{s|hr=map(s)|} SupplyCurve_{reg,s,ptpvb,y,step}$$

The total PV + battery hybrid system energy to the grid is limited to the inverter capacity.

(App3.D-19)

$$TradeCanLimit_{rcan,y,hr,csteps} \geq \sum_{rcanconn} TradeToFromCan_{rcanconn,rcan,y,hr,csteps}$$

$$TranLimitHr_{rcanconn,rcan,y,hr} \geq \sum_{csteps} TradeToFromCan_{rcanconn,rcan,y,hr,csteps}$$

Definition of Indices:

$rcanconn = domestic\ EMM\ region\ which\ has\ connections\ to\ Canadian\ regions$

The above constraints are the Canadian trade limits. The top constraint limits the Canadian trade to all connected domestic regions to the Canadian trade supply curve step limit. The bottom constraint limits the Canadian trade over all supply steps to the transmission line limit of a given connection.

(App3.D-20)

$$\sum_{s,hr|hr=map(s),d|d=map(hr),m|m=map(es),step} Generation_{pt=H2,y,reg,step,hr} * Idaytq_{m,d}$$
$$\leq H2TurbineGeneration_{es,reg} \forall \{es, reg, y\}$$

$$\sum_{s,hr|hr=map(s),d|d=map(hr),m|m=map(es),step} Generation_{pt=H2,y,reg,step,hr} * Idaytq_{m,d}$$
$$\leq 0.85 * H2TurbineGeneration_{es,reg} \forall\{es, reg, y\}$$

The above constraints are the hydrogen generation limits. Here are two constraints which set the maximum (top constraint) and minimum (bottom constraint) generation of hydrogen. We set a flexible limit to avoid infeasibility due to a single equality constraint. The upper limit is taken from the solution of the Electricity Fuel Dispatch (EFD) submodule. This constraint ensures that the total hydrogen turbine generation hourly profile in REStore does not surpass the corresponding hourly electrolyzer load sent from the Hydrogen Market Module (HMM).

Background information on the capacity credit algorithm for battery storage

The capacity credit available for battery storage is dependent on the amount of energy stored in available batteries during net peak load hours. It is assumed to decline with additional capacity installed on the grid. Battery storage reduces or flattens, the peak load, and as a result the new peak load is lower in magnitude but longer in duration as more battery capacity is added to the grid. Because batteries have a limited duration of 4 hours in the model, the ability of battery storage to meet the entire duration of the peak decreases as the peak increases in length, and thus the capacity credit for battery storage decreases.

$$Net\_Load\_Battery_h \ = Net\_Load_h \ – \ Battery\_Energy\_Stored_h$$

$$Peak\_Net\_Load\_Battery = \ average \ Net\_Load\_Battery_h \text{ in top 1\% of hours}$$

$$Peak\_Net\_Load = \ average \ Net\_Load \text{ in top 1\% of hours}$$

(App3.D-21)

$$batt\_stor\_cap\_credit = \frac{Peak\_Net\_Load\_Battery}{Peak\_Net\_Load}$$

Battery storage capacity credit can be calculated using the load duration curve (LDC) method, as implemented by Lawrence Berkeley National Laboratory.[40] The LDC is an hourly load curve sorted from highest load to lowest hourly load values. A *Net LDC,* Net_Load$_h$, can be created by first reducing the hourly load curve by the generation from non-dispatchable technologies such as solar or wind, and then sorting the hours by load. A *Storage Net LDC,* Net_Load_Battery$_h$, can be produced by further reducing the hourly load curve by the potential generation from battery storage units, represented by the amount of energy stored in the batteries in any given hour, and then sorting the hours by load.

For battery storage, the Peak_Net_Load is defined as the average Net_Load in the top 1% of hours of the net LDC. The ratio of the peak load from the Storage Net LDC to the peak load from the Net LDC represents the decrease in the highest net load hours, or the flattening of the peak load. From this ratio, the battery storage capacity credit is determined by region and used to satisfy the reserve margin constraint.

PV battery hybrid also uses the storage capacity credit value in calculating its capacity credit in each year and region. Since the PV battery hybrid technology only has one third of the battery capacity per

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[40] Lawrence Berkeley National Laboratory, "Simple and Fast Algorithm for Estimating the Capacity Credit of Solar and Storage," 2020.

inverter capacity as a standalone battery, the capacity credit is divided by 3. This battery value is added to the capacity credit of the standalone PV technology. The sum of these values may be greater than 1.0, so the capacity credit is then capped at 1.0. Refer to RFM documentation section 2 for more details on the method to calculate the PV capacity credit.

(App3.D-22)

$$pv\_batt\_stor\_cap\_credit = \min(1.0, CC\_PV + batt\_stor\_cap\_credit/3.0)$$

4. Electricity Fuel Dispatch Submodule

Model summary

The Electricity Fuel Dispatch Submodule (EFD) determines the utilization of available capacity, as determined in the Electricity Capacity Planning (ECP) Submodule, to meet demand on a least-cost basis subject to current environmental regulations. Available capacity is determined according to season of year, time of day, planned maintenance, outage rates, reserve margin, and variable fuel costs. A transmission network is constructed allowing electricity to be traded regionally. The dispatch and network configuration is similar to real-time capacity allocation. Units are dispatched for each time slice using available capacity and optimized on minimum costs until demand is satisfied and environmental and load constraints are honored. The ECP submodule determines the capacity needed in each year to meet demand. Demand is determined in the NEMS demand modules, and seasonal and hourly demands are determined in the Electricity Load and Demand (ELD) Submodule. Emissions of NO_X are accounted for by plant type and are determined based on the boiler type, control equipment (if any), and the utilization of capacity.

Fuel consumption is provided to the fuel supply modules while fuel and variable operations and maintenance (O&M) costs are used to determine electricity prices in the EFP submodule. The quantity of CO_2 captured by sequestration technologies is passed to the CCATS module. Electricity prices are provided to the demand models to determine electricity demand.

EFD dispatches the available generating capacity—including fossil-fueled, nuclear, and renewable generators as well as battery and pumped-hydro storage. Traditional cogeneration is determined in the demand models and is represented with a fixed vector to incorporate its contribution to meeting load. Interregional and international economy sales are also represented in the EFD. Utilities have the option to purchase electricity from another region in place of generating the power themselves. Distributed generation is included as a potential supply option. Available distributed generation capacity is operated according to prespecified utilization rates depending on the type (base or peak). A demand storage technology is available and operates similar to traditional pumped storage, which can be used to meet demand in any given slice but must replace the generation in other time slices. The demand storage technology could be used to model load-shifting from time-of-use pricing programs that use smart meters, but is not currently activated in EMM.

EFD assumes compliance with environmental legislation, including the Clean Air Act Amendments of 1990 (CAAA). The *Annual Energy Outlook 2025* (AEO2025) incorporates the Cross State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), the Regional Greenhouse Gas Initiative (RGGI) and the California Assembly Bill 398: California Global Warming Solutions Act of 2006 (AB398). It reflects updates to tax credits as pass in the Inflation Reduction Act. The Reference case also incorporates updates to Section 111 that were finalized by EPA in spring of 2024 and regulate CO_2 emissions from existing coal-fired power plants and new natural gas-fired plants.

EFD is a linear programming (LP) algorithm, which is a flexible approach to model electric generator dispatch in a realistic manner. It provides an optimal solution for unit dispatch and electricity trade across all regions simultaneously.

Model purpose

Model objectives

The purpose of the EFD is to represent the economic, operational, and environmental considerations in electricity dispatching and trade. The EFD allocates available generating capacity to meet the demand for electricity on a minimum cost basis, subject to engineering constraints and to restrictions on emissions such as sulfur dioxide (SO_2), nitrogen oxides (NO_X), mercury (Hg), and carbon dioxide (CO_2). The primary use of the EFD, as a component of the EMM and NEMS, is to develop projections for the *Annual Energy Outlook 2025* (AEO2025) and other analyses. For the electric power industry, the model projects fuel consumption and both average and marginal fuel and operating costs, for each year in the projection horizon. Intermediate projections of SO_2 and Hg emissions are calculated (final values come from the Coal Market Module [CMM]), as well as the projections for NO_X and CO_2 emissions.

The EFD represents the dispatch and trade decisions at the regional level. These regions, referred to as NEMS electricity supply regions (or EMM regions), are based on North American Electric Reliability Corporation (NERC) regions and subregions and Independent System Operator and Regional Transmission Organization region boundaries (Chapter 1, Figure 3). The primary inputs from other NEMS modules are the demands for electricity and fuel prices. The resulting fuel consumption is passed to the respective fuel supply models. The fuel supply modules and end-use demand modules use other regional aggregations (census regions and divisions, coal and natural gas supply regions, etc.). The interactions between the EFD and other modules of NEMS and other regional issues, including the required transformations between different regional structures, are described later in this section.

EFD only incorporates current regulatory strategies to comply with emissions limits that can be implemented during dispatching, in other words, fuel switching. Retrofitting units with pollution control equipment is represented in the ECP.

Another feature of EFD is the ability to engage in interregional economy transactions. Utilities are allowed to purchase power from utilities in neighboring regions if it is economical to do so and transmission capacity is available. Within a contiguous time slice, simultaneous dispatch and trade are simulated by a dispatch of power in the exporting region instead of in the importing region. Least-cost units are fully utilized if there is demand and transmission capacity. Transmission capacity for Canadian provinces is represented for trade with the United States. An input file provides information on the amounts of excess electricity supply available, by season and time slice, from each Canadian province.

Relationship to other modules

EFD requires input data from exogenous sources, other modules of NEMS, and other submodules of the Electricity Market Module. This section contains an overview of the data flows within the EFD. Figure 9 contains an overview of the data flows both into and out of the EFD submodule.

Exogenous inputs. The EFD requires cost and performance data for both existing and future electricity generating units to complete the dispatch decision. This information is obtained for existing units from various EIA and Federal Energy Regulatory Commission (FERC) survey forms and contractor reports prepared for EIA. Cost and performance data for future generating units were updated for AEO2025

based on a report prepared by external consultants.[41] Transmission constraints and trade relationships are also input to incorporate firm and economy trade. Firm trade contracts are culled from the FERC Form 1 and additional information obtained from utility integrated resource plans and ISO reports. Interregional transmission capacity limits are primarily derived from input files to the National Renewable Energy Laboratory's ReEDS (Regional Energy Deployment System) model.

SO_2, NO_X, Hg, CO_2, carbon, carbon monoxide (CO), and volatile organic compounds (VOC) emission rates and ash retention rates are also provided to determine annual emissions. A full listing of the data sources for exogenous inputs is available in Appendix 4.B.

Nuclear fuel cost projections are calculated through offline analysis and read in as exogenous inputs.

Inputs from other modules.[42] The demand modules provide electricity demand by sector. These demands are aggregated and mapped to a load duration curve in the Electricity Load and Demand (ELD) Submodule before the dispatch decision.

The residential, commercial, and industrial demand modules represent traditional cogeneration and other electricity production at residential and commercial buildings and industrial facilities. The generation estimates provided by these modules are converted to capacity (assuming a 100% capacity factor) and are assumed, in the LP, to provide this fixed amount to meet load. The renewable fuels model provides capacity factors by load slice for the intermittent technologies to limit their availability to the appropriate seasons and times of day.

Fossil fuel prices are provided by the fuel supply modules of NEMS. The EFD builds supply curves for natural gas and oil supplies based on the current year price and quantity from the other models. In this way, the EFD can reflect price changes because of significant shifts in fuel use as a result of the dispatch decision, before entering another NEMS iteration. Because the electricity and coal markets are closely related (coal is the primary input fuel for electricity production and the primary source for emissions produced from electricity generation), EFD includes a detailed representation of the coal supply curves contained in the CMM.

The ECP submodule provides the annual available capacity to be used in the dispatch decision as well as the share of biomass cofiring that is allowed from coal-fired plants. The ECP determines any penalty costs necessary to meet constraints on NOx emissions, and these costs are passed to the EFD for use in dispatching decisions. Some policy cases include a renewable portfolio standard (RPS), requiring a certain percentage of total sales or generation to come from renewable sources. If a renewable portfolio standard (RPS) is in place, ECP passes the credit price to EFD, and EFD simply adjusts the operating costs to include the buying or selling of credits. The RPS is not modeled explicitly in EFD because the primary way to meet the target is building new capacity, which must be determined by ECP. However, the

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[41]Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, Sargent & Lundy, January 2024.

[42] A synopsis of NEMS, the model components, and the interrelationships of the modules is presented in *The National Energy Modeling System: An Overview* (https://www.eia.gov/outlooks/aeo/nems/overview/pdf/0581(2023).pdf). Detailed documentation of the modeling system and any of the modules is available in a series of documentation reports available online at https://www.eia.gov/outlooks/aeo/nems/documentation/.

capacity build decisions and renewable credit price projections are passed to EFD so that the impacts of RPS are represented.

EFD determines the allocation of generating capacity to meet electricity demand. The output of this decision is needed to determine the price of electricity and to account for 1) the utilization of the fuel inputs, 2) renewable generation, and 3) emissions. In particular, EFP requires fuel and variable O&M costs to determine the price of electricity. For competitive pricing, the marginal cost for each region can be easily determined. The fuel supply modules require the quantity of fuel consumed for the pricing of those fuels and for calculating total fuel use by all sectors. EFD provides regional SO_2 and Hg removal rates to CMM, and the final SO_2 and Hg emissions are computed in the CMM and are passed to the Integrating Module. Emissions of NO_X are calculated in EFD, based on NO_X emission rates determined by plant and boiler type. Emissions of CO_2 as well as the amount of CO_2 captured by sequestration is calculated in EFD.

Output reports provide projections of generation and fuel consumption by plant and fuel type, for both electric generators and nontraditional cogenerators and for interregional and international economy trade. Reports include emissions and contain both national and regional projections. A standard set of national and regional projections are provided on EIA's website.

Figure 9. Input/output flows for the Electricity Fuel Dispatch Submodule
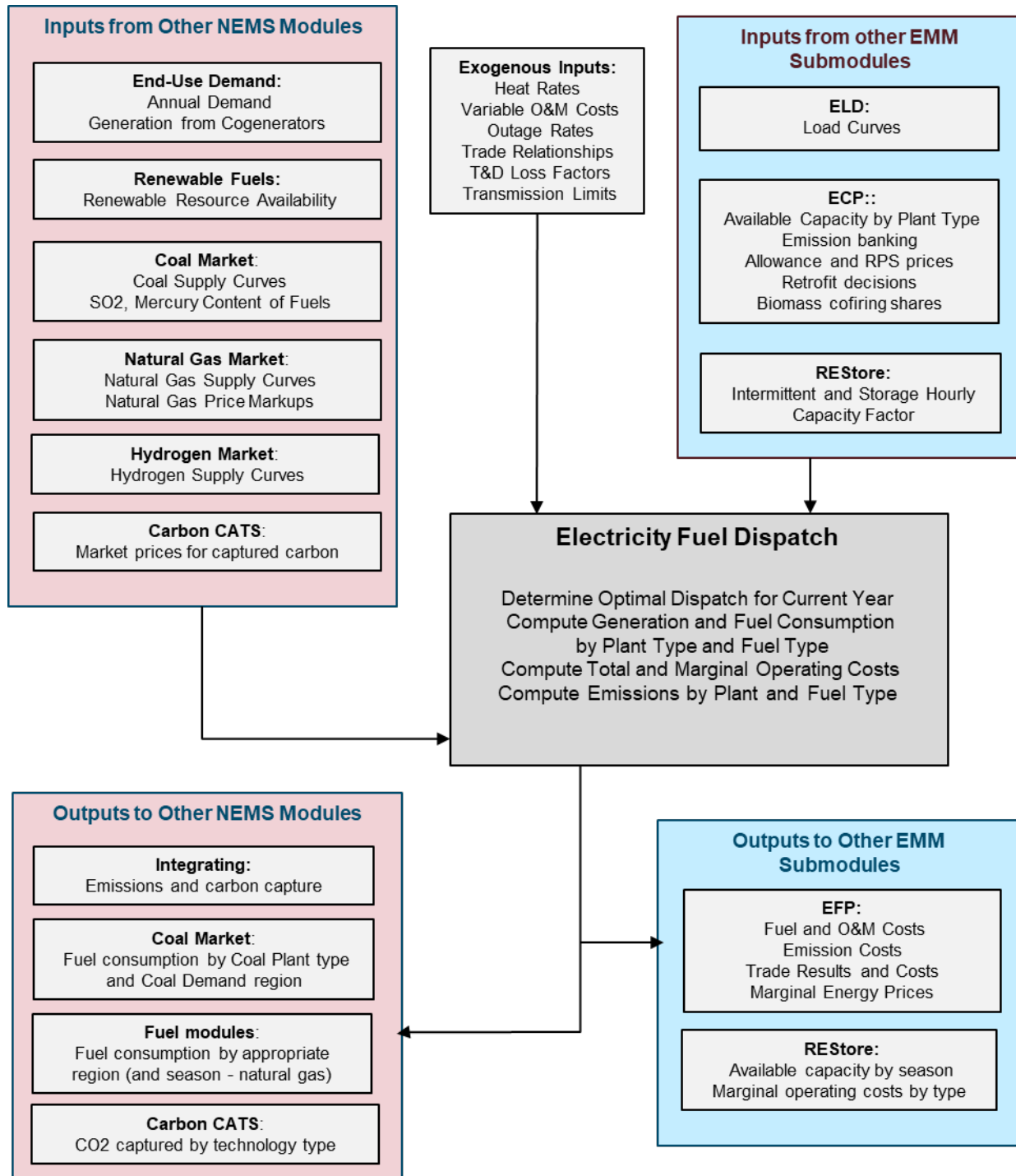
Model rationale

Theoretical approach

Basic model approach. EFD uses an LP approach to provide a minimum-cost solution to allocate (dispatch) capacity to meet demand. Dispatching involves deciding what generating capacity should be operated to meet the demand for electricity, which is subject to seasonal, daily, and hourly fluctuations. The objective of EFD is to provide an economic/environmental dispatching solution. In an economic (least-cost) dispatch, the marginal source of electricity is selected to react to each change in load. If load is increasing, then the cheapest available source of electricity is brought online. Similarly, if demand is decreasing, then the most expensive source of electricity currently operating is shut down. In environmental dispatching, the demand for electricity must be satisfied without violating certain emissions restrictions. EFD integrates the cost-minimizing solution with environmental compliance options to produce the least-cost solution that satisfies electricity demand and restricts emissions to be within specified limits.

Environmental issues that are incorporated in the EMM-NEMS include compliance with SO_2 and NO_X restrictions specified in the Clean Air Act (New Source Performance Standards—[NSPS], Revised New Source Performance Standards—[RNSPS], and Clean Air Act Amendments—[CAAA]). AEO2025 includes the CSAPR, which imposes stricter restrictions on SO_2 and NO_X for some states, while also incorporating the MATS requirements for Hg and acid gases. EFD also represents the limits on CO_2 emissions specified in AB398 for California, as well as the power sector CO_2 emission targets from RGGI for a group of 11 northeastern states. The AEO2025 Reference case also incorporates updates to Section 111 of the CAA to restrict CO_2 emissions from existing coal-fired power plants and certain new natural gas-fired power plants.

Demand can be characterized by a load curve, which is a plot of power demand (load) versus time (Figure 10). The highest point on the curve, the peak point, defines the capacity requirement. The capacity allocated to meet this last increment of demand is used infrequently during the entire period. On the other hand, the mix of capacity needed to satisfy demand at the base, or minimum point of the curve, is required on a continuous basis. The percentage of time capacity required at each slice of load is called a capacity factor (utilization rate). The aggregate capacity factor for the load at the base of the curve is 100%, and it approaches 0% at the peak of the load curve.

Figure 10. Typical load curve

megawatt
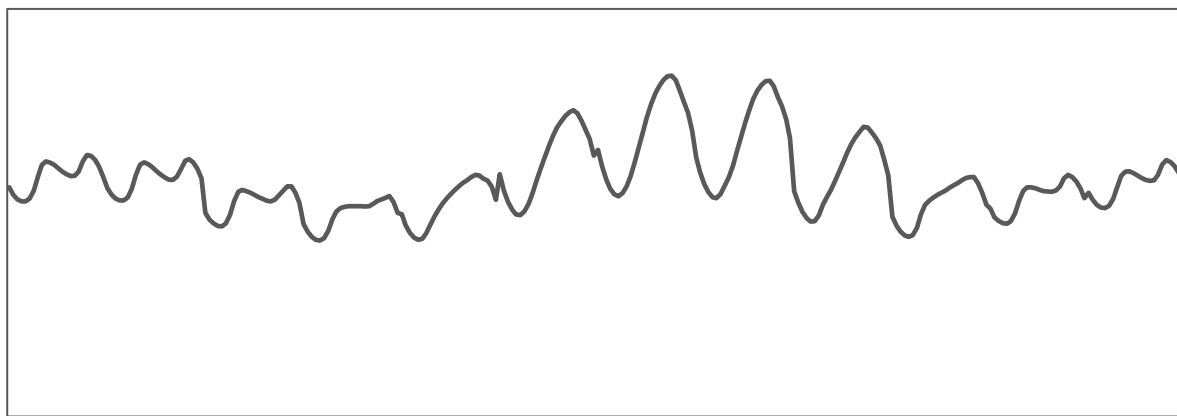
hour

The relationship between capacity requirements and capacity utilization can also be illustrated by a load duration curve, which is obtained by reordering the demands for power in descending order rather than chronologically (Figure 11). This curve shows the capacity utilization requirements for each increment of load. The height of each slice is a measure of capacity, and the width of each slice is a measure of the utilization rate or capacity factor. The product of the two is a measure of electrical energy (for example, kilowatthours). The problem is to determine which capacity types to assign to each of these slices of load and what fuels to use in each of these capacity types (to represent switching in multi-fuel units).

In the EFD, there are three seasonal load curves for each region with each load curve representing four months. Each load curve contains three vertical slices, categorizing the load by magnitude (height) and time. The EFD dispatches available capacity to meet load in each of these slices. Note that although the load curve re-orders the load segments, the chronology is maintained to represent maintenance scheduling for capacity and to model economy trade.

Figure 11. Typical load duration curve

Capacity Requirements (MW)

Capacity Utilization Rate (0% to 100%)
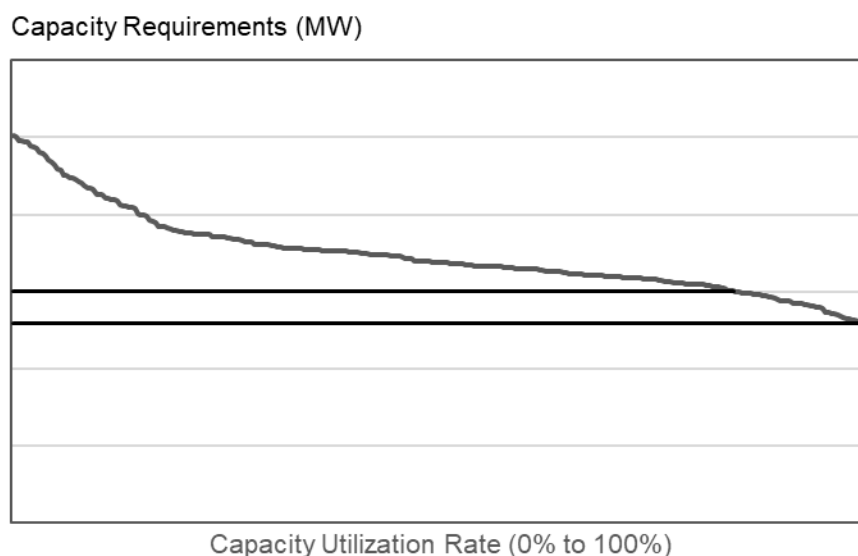
The algorithm used for the dispatch decision is a straightforward LP formulation, simulating the electric transmission network on the EMM region level and simultaneously dispatching capacity regionally by time slice until demand for the year is met. Traditional cogeneration and firm trade capacity is removed from the load duration curve before the dispatch decision. Capacity costs for each time slice are estimated based on fuel and variable O&M costs and are adjusted for RPS credits, if applicable, and production tax credits. Capacity is then allocated (in a cost minimization LP) for each time slice for the entire United States under certain considerations/constraints (in other words, engineering considerations limit the range of operation for certain capacity types and are incorporated using minimum and maximum capacity factors) until demand is satisfied. Generators are required to meet planned maintenance requirements, as defined by plant type. Next, generation and fuel usage is determined in each area for which the capacity has been allocated. Each of the nine time slices represents an area under the load curve to allocate specific kinds of capacity based on costs and engineering considerations. Generators are permitted to meet demand in either the region where they are located or in a neighboring region if transmission capacity is available. Excess production that is cheaper would be available for export to displace more expensive capacity in importing regions.

Assumptions

The assumptions of the EFD include the representation of the Clean Air Act Amendments of 1990 (CAAA) and aggregation issues related to electricity supply and demand. Details on specific cost and performance assumptions used in the EMM are published on EIA's website in the *Assumptions to the Annual Energy Outlook*. The Clean Air Act and its subsequent amendments contain federal regulations for SO2 and NOx emissions by electric utilities. The CAAA set up a system of marketable allowances to emit SO_2. Each allowance entitles the holder to emit one ton of SO_2. Allowances may be traded among utilities and nonutilities, so the limit on total emissions is a national rather than a unit-level limit.

Although the marketable allowance program in the CAAA is economically attractive, it is difficult to model. The CAAA does not set plant-specific emission rate limits. Rather, the CAAA sets national limits on the emissions of SO_2. Utilities are free to choose from a wide array of options to reduce their SO_2 emissions to the level of allowances allotted to them. Among the major options available to utilities are switching to the use of lower-sulfur fuels, reducing the utilization of their relatively high-emission units while increasing the utilization of their low-emission units, adding emissions reduction equipment at some generating facilities, purchasing additional allowances from others, or purchasing power from utilities in neighboring regions that have lower emissions. Thus, representing utility efforts to minimize their costs of complying with the CAAA requires a complex nationwide analysis.

The Coal Market Module (CMM) and EFD work together to ensure that emissions of SO_2 do not exceed specified limits set by the CAAA and the CSAPR and that mercury emissions meet the MATS removal standards. Because the mix of coals used significantly affects the emissions produced, the EFD includes a detailed representation of the coal supply matrix. Therefore, the EFD can also consider the rank of the coal and sulfur and mercury contents of the fuel used when determining the optimal dispatch. In that way, EFD and CMM can more easily achieve convergence to the optimal coal consumption.

EFD includes operating options for reducing emissions, which are based on short-term operating (fuel and variable O&M) costs. During dispatching, emissions can be reduced by switching from fuels with high emission rates to fuels with low emission rates.

For each of the 25 electricity supply regions, the EFD also represents trading of emission allowances, as provided for in the specific regulation. That is, utilities with relatively low costs of reducing emissions may over-comply (in other words, reduce emissions beyond their required level) and sell their excess allowances to utilities with comparatively high reduction costs. This trading of allowances assumes that the market for allowance trading is perfect, in other words, is based only on a cost saving. However, there are other factors involved in allowance trading that are not currently incorporated, such as local pressure for utilities to reduce emissions in place of purchasing allowances. On a national level, allowance trading does not lower total emissions, but it reduces the overall cost of achieving the specified emissions target. Following the implementation of EPA's Mercury and Air Toxics (MATS) rule, which generally required the installation of post-combustion controls, SO_2 emissions reported to EPA have been below the cap set by the Clean Air Act amendment programs (CSAPR).

EFD also represents updates to Section 111 of the CAA regulating CO_2 emissions from existing coal, oil, and natural gas-fired steam generating units and new natural gas-fired combustion turbines. As discussed in the previous chapter, the ECP is responsible for making most of the compliance decisions regarding retrofit, conversion or retirement of the existing coal plants, and the EFD operates the units as determined. EFD enforces any capacity factor limits on the new natural gas-fired power plants without CCS.

There are also assumptions regarding both the supply and demand for electricity in EFD, particularly related to aggregation issues. Forced outages are assumed to occur randomly. The capacity that is out-of-service at any given time is based on the assumed average forced outage rate for each plant. Also, utilities in each of the 25 electricity supply regions are operated as a tight power pool, meaning that all

generators can service load anywhere within a region. Because this aggregation of generating capacity does not address transmission and other engineering constraints that may limit dispatching of particular plants, the effect is that intra-regional trade is not represented. On the demand side, the load duration curve aggregates loads from many utilities to three points per season and region. Although this aggregation may not fully represent load variations, it is necessary as a result of computer time and resource constraints.

Model structure

Introduction

EFD is executed for each year and iteration of the model projection to determine the amount of capacity dispatched, fuels used, electricity trade, and costs to meet the yearly level of demand. The EFD simultaneously solves for these variables for all load slices within a projection year. The EFD uses a linear programming (LP) formulation to compete generating capacity and transmission capacity on the supply side with the demand-side options for meeting load. It dispatches a mix of capacity that minimizes costs on a national basis subject to certain conditions and constraints such as complying with environmental regulations. The capacity mix includes restrictions on the type of capacity that is allowed to operate in certain load slices based on engineering constraints. Seasonal and daily fluctuations and transmission and distribution losses are accounted for. There are also constraints on emissions.

EFD prepares input data, solves the LP model, and provides the required outputs to the other submodules of EMM and the modules of NEMS. The matrix is created for the first iteration of each year. The objective function represents the costs of generation and transmission. The coefficients describe the available capacity for base, intermediate, and peak load slices, demands, and constraints, most of which are specific to each of the time slices. The capacity level is scaled to account for forced outages and load following, while planned maintenance outages are scheduled within the LP.

The following section provides a mathematical description of the subroutines and LP model and specifies the objective function and equations of the constraint matrix. The model uses the Advanced Interactive Multidimensional Modeling System (AIMMS) software to create and store coefficients in a database, solve the optimization problem, and retrieve the solution.[43]

Key computations and equations

This section provides the mathematical specification of EFD. EFD uses a linear programming algorithm, which incorporates trade as well as dispatch in the cost minimization decision. The dispatch and trading of capacity is solved simultaneously to meet regional demands over the entire United States (subject to certain operating and engineering constraints, discussed in detail in the solution algorithm constraints section).

The objective of EFD is to project economic and environmental dispatch and electricity trade decisions. In the LP optimization, the costs of generation, trade, and transmission are minimized for the entire

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[43] AIMMS (Advanced Interactive Multidimensional Modeling System) is a software system designed for modeling and solving large-scale optimization and scheduling-type problems. It consists of an algebraic modeling language, an integrated development environment for both editing models and creating a graphical user interface around these models, and a graphical end-user environment.

United States. The decision variables represent options for operating the generating units under different modes with different fuels and options for the timing of electricity trade transactions. The marginal source of electricity is selected for each time slice and reacts to changes in load.[44] The demand for electricity must also be satisfied without violating certain engineering and emissions restrictions. Environmental, load-related, and capacity constraints are placed on the dispatch decisions. EFD integrates the least-cost solution with environmental compliance and engineering constraints. Environmental issues incorporated into NEMS include compliance with current SO_2, NO_X, and Hg restrictions, as discussed above in *Assumptions*.

EFD projections domestic economy trade by including the option of dispatching (in other words, purchasing) capacity in one region to serve a different region's demand. The load representation preserves additional chronological information to allow for energy purchases from extra regional utilities within physical limits of the transmission system (the requirement is to be able to match the blocks of energy available in the exporting region to the simultaneous need for power in the importing region).[45] Limits on total energy available during each demand slice and transmission line constraints are applied to control trade. Additional transmission costs and energy losses associated with trade are assigned to the exported power.

Initial operating costs (fuel and operations and maintenance expenses) are accumulated by plant groups. These costs are also adjusted by the production tax credit and RPS credits, where applicable.

In computing available capacity for a time slice, engineering considerations that may limit the range of operation for a given capacity type are incorporated. Minimum and maximum capacity factors are used to prevent base load plants from operating only in the peak slices. For instance, nuclear units do not typically operate as peaking capacity because they cannot be started or stopped quickly. The operating range is represented by a set of trigger points that identify the point (or points) that correspond to the capacity factor limits. The model takes these trigger points into account when determining the possible operating modes for each technology.

For each plant type, fuel consumption is computed by multiplying generation by the fuel share and heat rate for each fuel. SO_2 and mercury emissions are calculated in EFD, but reported values are derived in CMM. NO_X emissions are calculated in EFD based on boiler and fuel type.

The following provides the mathematical specification of the EFD's solution algorithm. This list of variable names and dimensions is unique to Chapter 4.

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[44] If load is increasing, then the cheapest available source of electricity is brought online. Similarly, if demand is decreasing, then the most expensive source of electricity currently operating is shut down.

[45] Note that it is possible for electrical energy to flow in one direction during a season and in the opposite direction during another season.

Dimensions:

a	=	Activated Carbon Option
b	=	Fuel Region—Unique Combination of Census, Coal, and Natural Gas Regions
c	=	Dispatchable Capacity Type
d	=	Fuel Supply Curve Step
e	=	Export Electricity Supply Region
f	=	Fuel Share Option
g	=	Import Electricity Supply Region
h	=	Canadian Supply Region
i	=	Intermittent Renewable/Storage Technology
j	=	Natural Gas Season
k	=	Capacity Type Other Than Capacity Type c
l	=	Vertical Load Steps (Load Slice) Within a Season
m	=	Mode of Operation (Base, Intermediate or Peak)
n	=	Renewable Capacity Type
p	=	Plant Group
q	=	Canadian Supply Step
r	=	Electricity Market Module (EMM) Region
s	=	Season
t	=	Distributed Generation Technology Type (Base, Peak)
u,u'	=	SO2 Containment Area
v	=	NOx Containment Area
w	=	Natural Gas Supply Region
x	=	Oil Supply Region
y	=	Current Model Year
z	=	Carbon Containment Area
B	=	Capacity Type for Dedicated Biomass
C	=	Subset of Dispatchable Capacity Types c That Are Coal-Fired
D	=	Subset of Dispatchable Capacity Types c That Are Not Coal-Fired
F	=	Subset of Coal Capacity Types C Without Scrubbers
G	=	Subset of Coal Capacity Types C With Scrubbers
J	=	Coal Supply Curves
K	=	Subset of Coal Supply Curves J That Are Subbituminous
L	=	Subset of Coal Supply Curves J That Are Lignite
M	=	Supply Curve Steps
N	=	Coal Demand Regions
O	=	Census Division

Terms in Objective Function and Constraints

There are three types of terms in the equations—decision variables, right-hand sides, and coefficients. These terms are described below. Before the definition of these items, the type is indicated using (D) for decision variables, (R) for right-hand sides, and (C) for coefficients.

AVGHG = (C) Average Mercury Content of the Entire Coal Stock (pounds per million Btu)

AVGSO2 = (C) Average Sulfur Content of the Entire Coal Stock (pounds per million Btu)

BNKHG = (R) Net Impact of Using or Adding to the Bank of Mercury Emissions in the Current Year

BNKSO2 = (R) Net Impact of Using or Adding to the Bank of SO2 Emissions in the Current Year

BP_{Nd} = (D) Quantity of Biomass Produced in Coal Demand Region N and Supply Step d (trillion Btu)

$BREQ_{psm}$ = (C) Consumption Requirement Per Unit of Capacity for Dispatchable or Renewable Plant Group p Operating in Season s and Operating Mode m (trillion Btu/GW)

BTU_{bB} = (D) Fuel Consumption by Dedicated Biomass Plants B in Fuel Region b (trillion Btu)

BTU_{bCf} = (D) Fuel Consumption by Coal-fired plants C Under Fuel Option f in Fuel Region b (trillion Btu)

BTU_{bDfj} = (D) Fuel Consumption by Natural Gas or Dual-fired Plants D Under Fuel Option f in Fuel Region b and Natural Gas Season j (trillion Btu)

BTU_{bDf} = (D) Fuel Consumption by Oil Plants D Under Fuel Option f in Fuel Region b (trillion Btu)

$BTUE_N$ = (D) Quantity of Biomass Fuel Used for Ethanol Production in Coal Region N (trillion Btu)

$BTUI_N$ = (D) Quantity of Biomass Fuel Used in the Industrial Sector in Coal Region N (trillion Btu)

BTUN = (D) Fuel Consumption by Nuclear Plants (trillion Btu)

$CAPB_{ps}$ = (R) Total Available Capacity for Dispatchable Plant Group p in Season s (gigawatts)

$CARC_{bCf}$ = (C) Average Carbon Content for Coal Capacity Type C Under Fuel Option f in Fuel Region b (million metric tons per trillion Btu)

$CARD_{bDf}$ = (C) Average Carbon Content for Natural Gas or Dual-Fired Capacity Type D Under Fuel Option f in Fuel Region b (million metric tons per trillion Btu)

$CARR_c$ = (C) Average CO_2 removal rate for dispatchable technology c (fraction)

$CARIM_z$ = (C) Average Carbon Content for Electricity Imports to Carbon Containment Region z (million metric tons per billion kWh)

$CARLIM_{zy}$ = (R) Carbon Constraint in Containment Area z in Year y (million metric Tons)

$CARO_{bDf}$ = (C) Average Carbon Content for Oil-Fired Capacity Type D Under Fuel Option f in Fuel Region b (million metric tons per trillion Btu)

$CAROS_z$ = (C) Average Carbon Content for Out-of-State Generation for Carbon Containment Region z (million metric tons per billion kWh)

CBP_{Nd} = (C) Production Cost of Biomass for Coal Demand Region N and Supply Step d (dollars per million Btu)

CCP_{JM} = (C) Production Cost of Coal for Supply Curve J and Supply Step M (dollars per million Btu)

CCT_{JNCa} = (C) Tier-1 Transportation Cost for Coal Delivered from Supply Curve J to Coal Demand Region N Used in Capacity Type C with Activated Carbon Level a (dollars per million Btu)

$CCT2_{JN}$ = (C) Incremental Tier-2 Transportation Cost for Coal Delivered from Supply Curve J to Coal Demand Region N (dollars per million Btu)

CDP_d = (C) Production Cost of Distillate Fuel Oil for Supply Step d (dollars per million Btu)

CDT_x = (C) Transportation Cost for Distillate Fuel Oil Delivered to Oil Region x (dollars per million Btu)

CGP_d = (C) Production Cost of Natural Gas for Supply Step d (dollars per million Btu)

CGT_{wj} = (C) Transportation cost for Natural Gas Delivered to Gas Region w in Gas Season j (dollars per million Btu)

$CLCON_r$ = (D) Coal Consumption in Electricity Region r (trillion Btu)

$CLGEN_r$ = (D) Coal Generation in Electricity Region r (billion kWh)

$CLSHR_{bCf}$ = (C) Coal Share for Operating Capacity Type C in Fuel Region b and Fuel Option f (fraction)

$CNAVL_{hqsl}$ = (R) Available Canadian Power for Trading in Canadian Region h at Supply Step q in Season s and Load Slice l (gigawatts)

$CNTS_O$ = (C) Cost for CO_2 Captured from the Operation of Power Plants Eligible for Subsidies in Census Division O As Determined by CCATS Module (dollars/million metric tons)

$CNTX_O$ = (C) Cost for CO_2 Captured from the Operation of Power Plants Not Eligible for Subsidies in Census Division O As Determined by CCATS Module (dollars/million metric tons)

CNP = (C) Production Cost of Delivered Nuclear Fuel (dollars per million Btu)

CO_J = (D) Other Coal (Nonutility) Demand Satisfied from Supply Curve J (trillion Btu)

CO2B = (C) CO_2 content for Biomass Consumption (metric ton CO_2 / trill Btu)

CO2C = (C) CO_2 content for Coal Consumption (metric ton CO_2 / trill Btu)

CO2D = (C) CO_2 content for Natural Gas Consumption (metric ton CO_2 / trill Btu)

COF_{NC} = (C) Cofiring Share for Coal Capacity Type C in Coal Demand Region N (fraction)

$CONS_{JN}$ = (R) Quantity of Coal Contracts for Coal Supply Region J to Scrubbed Plants in Coal Demand Region N (trillion Btu)

CONSC = (D) Total U.S. Coal Consumption from *Short-Term Energy Outlook,* Bounded by an Assumed Input Tolerance (trillion Btu)

$CONU_{JN}$ = (R) Quantity of Coal Contracts for Coal Supply Region J to Unscrubbed Plants in Coal Demand Region N (trillion Btu)

CP_{JM} = (D) Quantity of Coal Produced from Supply Curve J and Supply Step M (trillion Btu)

CRP_d = (C) Production Cost of Residual Fuel Oil for Supply Step d (dollars per million Btu)

CRT_x = (C) Transportation Cost for Residual Fuel Oil Delivered to Oil Region x (dollars per million Btu)

$CSTBS_{psm}$ = (C) Variable Operating Cost for Dispatchable Plant Group p in Season s and Operating Mode m (million dollars per gigawatt)

$CSTCN_{hq}$ = (C) Cost of Canadian Power available from Canadian Region h and Supply Step q (million dollars per gigawatt)

$CSTHY_{psl}$ = (C) Variable Operating Cost for Hydro Plant Group p in Season s and Load Slice l (million dollars per gigawatt)

$CSTIN_{psl}$ = (C) Variable Operating Cost for Intermittent Plant Group p in Season s and Load Slice l (million dollars per gigawatt)

$CSTRNW_{psm}$ = (C) Variable Operating Cost for Baseload Renewable Plant Group p Operating in Season s and Operating Mode m (million dollars per gigawatt)

$CSTTR_{ge}$ = (C) Incremental Cost to Trade Power From Import Region g to Export Region e (million dollars per gigawatt)

CT_{JNCa} = (D) Quantity of Coal Transported from Supply Curve J to Coal Demand Region N Used in Capacity Type C with Activated Carbon Level a (trillion Btu)

CTLHG = (D) Mercury Emissions from Coal to Liquids Plants (tons)

CTLSO2 = (D) SO2 Emissions from Coal to Liquids Plants (thousand tons)

$CTS2_{JN}$ = (D) Quantity of Coal Transported at Additional Tier-2 Cost from Supply Curve J to Scrubbed Plants in Coal Demand Region N (trillion Btu)

$CTU2_{JN}$ = (D) Quantity of Coal Transported at Additional Tier-2 Cost from Supply Curve J to Unscrubbed Plants in Coal Demand Region N (trillion Btu)

DP_d = (D) Quantity of Distillate Fuel Oil Produced for Supply Step d (trillion Btu)

$DSSHR_{bDf}$ = (C) Distillate Share For Operating Capacity Type D in Fuel Region b and Fuel Option f (fraction)

DT_x = (D) Quantity of Distillate Fuel Oil Transported to Oil Region x (trillion Btu)

DVL_{NC} = (R) Limit on Lignite Use in Coal Capacity Type C in Coal Demand Region N (trillion Btu)

DVS_{NC} = (R) Limit on Subbituminous Coal Use in Coal Capacity Type C in Coal Demand Region N (trillion Btu)

$ELNOX_{cv}$ = (D) NOX emissions from Capacity Type c in NOX Region v (thousand Tons)

$ESCNOX_v$ = (D) Total NOX emissions Incurring the NOX Penalty Cost from the ECP in NOX Region v (thousand tons)

EXP_{rs} = (R) Maximum Transmission Capacity for Exports Allowed from EMM region r in Season s (gigawatts)

GEN_{psm} = (C) Generation Output from Plant Group p Used in Operating Mode M in Season s (hours)

GEN_{psl} = (C) Generation Output from Plant Group p Used in season s and Load Slice l (hours)

GEN_{ps} = (C) Generation Output from Plant Group p Used in Season s (hours)

GENSC = (D) Total U.S. coal generation from *Short-Term Energy Outlook* projection, Bounded by an Assumed Input Tolerance (billion kWh)

GP_d = (D) Quantity of Natural Gas Produced for Supply Step d (trillion Btu)

GT_{wj} = (D) Quantity of Natural Gas Transported to Natural Gas Region w in Gas Season j (trillion Btu)

$H2P_{Osd}$ = (D) Quantity of Hydrogen Gas Produced in Census Region O in season s for Supply Step d (trillion Btu)

$H2SHR_{bDf}$ = (C) Hydrogen Gas Share For Capacity Type D in Fuel Region b and Fuel Option f (fraction)

HGC_{JbC} = (C) Average Mercury Content of Coal-fired plant Type C Using Coal Supply Curve J in Fuel Region b (tons per trillion Btu)

$HGLIM$ = (R) Mercury Constraint (tons)

$HOURS_s$ = (C) Hours in Season s

HRS_{sl} = (C) Hours in Season s and Load Slice l

$HRFAC_{sl}$ = (C) Fraction of Total Seasonal Hours for Load Slice l and Season s

$HYAVL_{ps}$ = (R) Maximum Energy from Hydro Plant p in Season s (million kWh)

IMP_{rs} = (R) Maximum Transmission Capacity for Imports Allowed into EMM region r in Season s (gigawatts)

$LDREQ_{rsl}$ = (R) Load requirement for EMM region r in Season s and Load Slice l (million kWh)

MB_{ps} = (D) Capacity Taken Out for Planned maintenance for Plant Group p and Season s (gigawatts)

$MERC_c$ = (D) Mercury Emissions for Capacity Type c (tons)

MP_{rcs} = (D) Total Capacity Taken Out for Planned maintenance for EMM region r, Capacity Type c and Season s (gigawatts)

$MRREQ_{rc}$ = (R) Generation from Must Run Plants in EMM region r of Capacity Type c (million kWh)

$MVSO2_{uu'}$ = (D) SO2 Emissions Traded between SO2 Regions (thousand tons)

$NGSHR_{bDf}$ = (C) Natural Gas Share For Capacity Type D in Fuel Region b and Fuel Option f (fraction)

$NOXC_p$ = (C) Average NOx content of Plant Group p (pounds per million Btu)

$NOXPv$ = (C) NOx Allowance Price from ECP for NO_X Region v (dollars per ton)

NTS_O = (D) Amount of CO_2 Captured by Power Plants Eligible for Subsidies in Census Division O To Be Sent to CCATS Module (million metric tons)

NSX_O = (D) Amount of CO_2 Captured by Power Plants Eligible for Subsidies in Census Division O To Be Sent to CCATS Module (million metric tons)

NTX_O = (D) Amount of CO_2 Captured by Power Plants Not Eligible for Subsidies in Census Division O To Be Sent to CCATS Module (million metric tons)

$OPBS_{psm}$ = (D) Use Baseload Plant Group p in Season s in Operating Mode m (gigawatts)

$OPHY_{psl}$ = (D) Use Hydro Plant Group p in Season s and Load Slice l (gigawatts)

$OPIN_{psl}$ = (D) Use Intermittent Plant Group p in Season s and Load Slice l (gigawatts)

$OPRNW_{psm}$ = (D) Use Renewable Plant Group p in Season s in Operating Mode m (gigawatts)

$OPDS_{psl}$ = (D) Use Battery/Diurnal Storage Plant Group p in Season s and Load Slice l (gigawatts)

$PMBR_p$ = (R) Planned maintenance Requirement for Baseload Plant Group p (billion kWh)

$PMPR_{rc}$ = (R) Planned maintenance Requirements for All Capacity Type C in EMM region r (million kWh)

RP_d = (D) Quantity of Residual Fuel Oil Produced for Supply Step d (trillion Btu)

$RSSHR_{bDf}$ = (C) Residual Fuel Share For Operating Capacity Type D in Fuel Region b and Fuel Option f (fraction)

RT_x = (D) Quantity of Residual Fuel Oil Transported to Oil Region x (trillion Btu)

$SO2C_{JbC}$ = (C) Average SO2 Content for Coal Capacity Type C Using Coal Supply Curve J in Fuel Region b (pounds per million Btu)

$SO2R_x$ = (C) Average SO2 Content for Residual Fuel Oil in Oil Region x (pounds per million Btu)

$SO2LIM_{uy}$ = (R) SO2 constraint in Sulfur Region u and Year y (thousand tons)

$SO2V_{uy}$ = (R) SO2 Variability Limits Capping the Amount of Allowances That Can be Purchased by Sulfur Region u and Year y (thousand tons)

$SRCR_c$ = (C) Share of Excess Capacity of Capacity Type c Committed to Load That is Credited Against the Spinning Reserve Requirement (fraction)

$SRDS_{rsl}$ = (C) Share of Battery/Diurnal Storage Capacity Available to Meet the Spinning Reserve Requirement in EMM region r in Season s and Load Slice l (fraction)

SRE_{yegsl} = (D) Spinning Reserved Transferred from Export Region e to Import Region g in Season s and Load Slice l in Year y (gigawatts)

$SRINT_{ir}$ = (C) Fraction of Derated Intermittent Capacity i that Must be Matched with Spinning Reserves in EMM region r (fraction)

$SRPVH_{rsl}$ = (C) Share of Photovoltaic Battery Hybrid Capacity Available to Meet the Spinning Reserve Requirement in EMM region r in Season s and Load Slice l (fraction)

$SRRD_r$ = (C) Difference Between Seasonal Peak and Load Height Required for Spinning Reserve in EMM region r (fraction)

$SRRH_r$ = (C) Share of Load Height Required for Spinning Reserve in EMM region r (fraction)

$SRTC$ = (C) Share of Transmission Capacity That is Credited against Spinning Reserve Requirement (fraction)

$STFAC_i$ = (C) Generation Replacement Factor for Storage Technology type i (fraction)

STX_{rsl} = (D) Storage Capacity Replaced in Region r, Season s, and Load slice l (million kWh)

$SULF_{cu}$ = (D) SO2 Emissions by Capacity Type c in Sulfur Region u (thousand tons)

$TLOSS$ = (C) Transmission Losses Incurred between Regions (percent)

$TRAVL_{rhs}$ = (R) Transmission Capacity between EMM region r and Canadian Export Region h in Season s (gigawatts)

$TRCN_{hqrsl}$ = (D) Transfer Electricity from Canadian region h and Canadian Supply Step q to EMM region r in Season s and Load slice l (gigawatts)

$TREL_{gesl}$ = (D) Transfer Electricity to Import Region g from Export Region e in Season s and Load Slice l (gigawatts)

$TSTOCK$ = (D) Net Change in Coal Stock (trillion Btu)

$TS1_{JN}$ = (R) Limit on Coal Transported from Coal Supply Region J to Scrubbed Plants in Coal Demand Region N at Tier-1 Rates (trillion Btu)

$TU1_{JN}$ = (R) Limit on Coal Transported from Coal Supply Region J to Unscrubbed Plants in Coal Demand Region N at Tier-1 Rates (trillion Btu)

Objective function

The objective function of the dispatching algorithm minimizes total operating (fuel and variable O&M) costs and transmission costs of meeting demand while complying with environmental regulations for a given model year. The objective function is in millions of dollars. The cost components include the following:

- Production costs for coal, natural gas, hydrogen, oil, biomass, and nuclear fuel

- Transportation and activated carbon costs for delivering coal for Tier-1 and Tier-2 rates

- Transportation of natural gas and oil from supply regions to electricity fuel regions

- Operation costs of dispatchable capacity

- Operation costs of hydro capacity

- Operation costs of intermittent capacity

- Operation costs of dispatchable renewable capacity

- Operation costs of distributed generation capacity

- Costs of interregional trade

- Costs of international trade

- Costs of NOₓ emission controls

- Net Cost of transporting captured CO_2 for EOR or saline storage

(4-1)

$$
\begin{aligned}
& \sum_J \sum_M CCP_{JM} \cdot CP_{JM} + \sum_J \sum_N \sum_C \sum_a CCT_{JNCa} \cdot \overset{MIN}{CT}_{JNCa} + \\
& \sum_J \sum_N CCT2_{JN} \cdot CTS2_{JN} + \sum_J \sum_N CCT2_{JN} \cdot CTU2_{JN} + \\
& \sum_d CGP_d \cdot GP_d + \sum_w \sum_j CGT_{wj} \cdot GT_{wj} + \sum_d CDP_d \cdot DP_d + \sum_x CDT_x \cdot DT_x + \sum_{w'} \sum_s \sum_d CH2P_{w'sd} \cdot H2P_{w'sd} + \\
& \sum_d CRP_d \cdot RP_d + \sum_x CRT_x \cdot RT_x + \sum_N \sum_d CBP_{Nd} \cdot BP_{Nd} + CNP \cdot BTUN + \\
& \sum_p \sum_s \sum_m CSTBSpsm \cdot OPBSpsm + \sum_p \sum_s \sum_l CSTHYpsl \cdot OPHYpsl + \\
& \sum_p \sum_s \sum_l CSTINpsl \cdot OPINpsl + \sum_p \sum_s \sum_m CSTRNWpsm \cdot OPRNWpsm \\
& + \sum_p \sum_s \sum_m CSTDGpsm \cdot OPDGpsm + \\
& \sum_g \sum_e \sum_s \sum_l CSTTRge \cdot TREL\ gesl + \sum_g \sum_h \sum_q \sum_s \sum_l CSTCNhq \cdot TRCN\ ghqsl + \\
& \sum_v NOXPv \cdot ESCNOXv + \sum_O CNTS_O \cdot NTS_O + \sum_O CNTX_O \cdot NTX_O
\end{aligned}
$$

Description of constraints

Coal Submatrix. EFD contains a series of equations to represent the production, transportation, and consumption of coal by electric generators. These constraints simulate the costs and characteristics of the different coals described by supply curves in CMM and are also similar to the representation of coal supply in ECP. EFD makes decisions for generation and fuel consumption, subject to emissions limits, in this representation. The resulting coal demands are then passed to CMM.

EFD uses the same two-tier pricing system for transportation costs that is incorporated in CMM. This methodology assumes that the amount of coal that can be delivered at current rates is limited to historical flows. Additional quantities are assumed to require an incremental cost.

Each of the supply curves represents coal from a single coal region, characterized by one rank (bituminous, subbituminous, or lignite), emissions content (average), and cost structure. A coal region may contain more than one supply curve and the coal produced in a given coal region may be

transported for use by generators in multiple electricity regions. Similarly, coal-fired plants in a particular electricity region may be able to obtain fuel supplies from more than one coal region.

Material balance rows for supply. These equations balance the coal produced by a particular supply curve and the coal transported to generating plants (CT_{JNCa}). Each supply step (CP_{JM}) of a given supply curve represents the quantity of coal that can be produced annually at a specified cost. Production must also be sufficient to satisfy nonutility coal use (CO_J). The rows are specified as follows:

(4-2)
$$\sum_N \sum_C \sum_a CT_{JNCa} + CO_J - \sum_M CP_{JM} \leq 0$$

for every coal supply curve J.

Contract flows. These equations require minimum quantities of coal production to satisfy electricity contracts for coal produced by specific coal curves and transported to specific electricity generators. For coal used in unscrubbed plants, the contract flows are represented as follows:

(4-3)
$$\sum_F \sum_a CT_{JNFa} \geq CONU_{JN}$$

for every supply curve J to coal region N.

This equation requires that the coal transported from the supply curve J in coal region N to unscrubbed coal-fired plants F (CT_{JNFa}) must satisfy the contract amount ($CONU_{JN}$). The analogous constraints for contract flows to scrubbed plants are obtained by substituting the scrubbed capacity types G for the unscrubbed capacity types F and using the analogous contract quantity ($CONS_{JN}$).

Diversity requirements. Some coal-fired generator units are not able to burn subbituminous coal or lignite or can only use limited amounts. These equations impose limits on the quantity of subbituminous and lignite coal that can be used to satisfy coal demands by specified coal capacity types and regions. For subbituminous coal, the diversity constraints are represented as follows:

(4-4)
$$\sum_K \sum_a CT_{KNCa} \leq DVS_{NC}$$

for coal capacity types C in coal region N.

The quantity DVS_{NC} represents the maximum quantity of subbituminous coal that can be consumed by coal-fired plant type C in coal demand region N. Thus, the equation states that the sum of coal transported from the subbituminous supply curves K to coal-fired plant type C in coal region N cannot exceed the maximum allowable use of subbituminous coal. Similar constraints are also imposed for lignite use in coal capacity by replacing the subbituminous supply curves K with the lignite supply curves L. The corresponding limit on lignite is specified by the right-hand side DVL_{NC}.

Transportation rates. Transportation rates are applied using a two-tier system. The Tier-1 rates assume that the current rates are limited to historical flow levels. To deliver additional supplies, an incremental cost (Tier-2 rate) is incurred. The constraints on Tier-1 rates are imposed for unscrubbed capacity types F as follows:

(4-5) $$\sum_F \sum_a CT_{JNFa} - CTU2_{JN} \le TU1_{JN}$$

for every supply curve J in coal region N.

The quantity TU1$_{JN}$ represents the limit on coal that can be transported at Tier-1 rates from coal supply curve J to unscrubbed plants in coal demand region N. Thus, the equation ensures that the difference between the total transportation of coal from supply curve J to unscrubbed plants in coal region N (CT$_{JNFa}$) and the quantity of coal for unscrubbed plants subject to Tier-2 rates (CTU2$_{JN}$) does not exceed the limit delivered at Tier-1 costs. The analogous constraints for first tier flows to scrubbed plants are obtained by substituting the scrubbed capacity types G for the unscrubbed capacity types F, the amount of coal delivered to scrubbed plant at Tier-2 rates (CTS2$_{JN}$), and the corresponding limit on Tier-1 flows to scrubbed plants (TS1$_{JN}$).

Fuel supply/demand curves. Like the fuel curves described in the coal submatrix, these equations describe the price/quantity relationships associated with the production of fuels to satisfy the demand for natural gas, oil, and biomass fuels used in electricity generation. These constraints accumulate total fuel use so that the fuel price can vary directly with the amount required to produce electricity.

Material balance row for natural gas supply. This equation represents a national supply market for natural gas. Each supply step (GP$_d$) specifies the quantity of natural gas that can be produced annually at a particular cost (represented by the supply step *d*). The transportation variables (GT$_{wj}$) describe the delivery of natural gas to generating plants in natural gas region w and natural gas season s. This row is defined as follows:

(4-6) $$\sum_w \sum_j GT_{wj} - \sum_d GP_d \le 0$$

Material balance rows for oil supply. These equations represent a national supply market for residual and distillate fuel oil. For residual fuel oil, each supply step (RP$_d$) specifies the quantity of residual fuel that can be produced annually at a given cost. The transportation variables (RT$_x$) describe the delivery of residual oil to generating plants in oil region x. This row is defined as follows:

(4-7) $$\sum_x RT_x - \sum_d RP_d \le 0$$

The corresponding production and transportation variables for distillate fuel oil are DP$_M$ and DT$_x$, respectively. The analogous supply row for distillate fuel oil is given by the following:

(4-8) $$\sum_x DT_x - \sum_d DP_d \le 0$$

Material balance rows for biomass supply. The biomass supply curves balance the production and consumption of biomass fuel. In addition to dedicated biomass plants, this fuel can also be used for cofiring in coal-fired plants. Fuel use in biomass plant type B located in those fuel regions b that correspond to coal region N is represented by a decision variable (BTU$_{bB}$). Biomass fuel used for cofiring in coal-fired plants is the product of the fuel used in coal-fired plants (BTU$_{bcf}$) and the cofiring share (COF$_{NC}$).

Biomass required in the industrial sector (BTUI$_N$) and ethanol production (BTUE$_N$), both of which are determined in the end-use sector, are also included because these uses compete for the available supplies. The production of biomass in coal region N is represented by a set of price/quantity supply steps (BP$_{Nd}$). As a result, the supply curves are specified for each of the coal regions, as follows:

$$(4\text{-}9) \quad \sum_{b \in N} BTU_{bB} + \sum_f \sum_{b \in N} \sum_C COF_{NC} \bullet BTU_{bCf} + BTUE_N + BTUI_N - \sum_d BP_{Nd} \leq 0$$

for each coal region N and where B is the dedicated biomass plant type.

Fuel consumption balancing rows. For each fuel type, these constraints ensure that the amount of fuel transported to the EFD fuel region from the supply curves is sufficient to meet the amount of fuel consumed by the plants based on the dispatch solution. Negative terms define the fuel transported while positive terms represent the fuel consumed. There are sets of constraints for each fossil fuel and for hydrogen and biomass fuels.

Coal's constraints are as follows:

$$(4\text{-}10) \quad -\sum_J \sum_a CT_{JbCa} + \sum_f CLSHR_{bCf} \cdot BTU_{bCf} + \sum_f \sum_j CLSHR \cdot BTU_{bDfj} \leq 0$$

for every fuel region b, and coal-fired plant type C and gas plant D that allow coal and natural gas cofiring. The fuel share options, f, provide for different fuel options for the plant. For coal-fired plants, the fuel options would primarily reflect cofiring with biomass. EFD uses the ECP solution for cofiring levels, so there is only one fuel option for coal-fired plants in this equation. The ECP can decide to convert a coal-fired plant to allow coal and natural gas cofiring, and although that plant is then accounted for under a more generic fossil steam category, it can still operate partially with coal and will intersect the appropriate coal balance constraint, reflected in the last term.

Natural gas's constraints are as follows:

$$(4\text{-}11) \quad -GT_{wj} + \sum_{b \in w} \sum_D \sum_f NGSHR_{bDf} \cdot BTU_{bDfj} \leq 0$$

for every natural gas region w and natural gas season j. The fuel share options are used for dual-fired units to provide for different levels of natural gas use by the given plant type. Because natural gas prices vary by season, the constraints are set up by season so that plants can operate with a different mix of fuels by season, based on the optimal pricing.

Hydrogen constraints are as follows:

$$(4\text{-}12) \quad -H2P_{Osd} + \sum_{b \in O} \sum_D \sum_f H2SHR_{bDf} \cdot BTU_{bDfs} \leq 0$$

for every census region O and season s. Currently the only hydrogen technology is one that is assumed to operate 100% with hydrogen, but options could be considered in the future that allow cofiring with natural gas. Because hydrogen gas prices vary by season, the constraints are also set up by season to capture the appropriate costs in the objective function.

Distillate's constraints are as follows:

$$(4\text{-}13) \quad -DT_x + \sum_{b \in x} \sum_D \sum_f DSSHR_{bDf} \cdot BTU_{bDf} \ \leq \ 0$$

Residual fuel's constraints are as follows:

$$(4\text{-}14) \quad -RT_x + \sum_{b \in x} \sum_D \sum_f RSSHR_{bDf} \cdot BTU_{bDf} \ \leq \ 0$$

for every oil region x. Again, in this case dual-fired units that can run with natural gas or oil would have different fuel options based on the fuel mix. The options are based on the maximum natural gas and oil shares for the given plant type and region, based on historical data read in from the EMM plant database.

Energy consumption balancing rows. The following constraints ensure that the amount of fuels consumed by each plant type, in each fuel region, equals the amount of fuel required based on the generation of all the plant groups of that plant type and in that region. The formulation of the constraint varies slightly based on the plant type and its possible operating modes. Baseload/intermediate capacity types are allowed to run in certain modes. These plant types cannot be brought up and down quickly, so they should not be dispatched by each time slice independently. Instead, there are a minimum number of slices they must run to be considered economical, defined by the assumed minimum capacity factor.

Coal-fired plant types' constraints are as follows:

$$(4\text{-}15) \quad -\sum_f BTU_{bCf} + \sum_p \sum_s \sum_m BREQ_{psm} \cdot OPBS_{psm} \leq 0$$

for every fuel region b and coal-fired plant type C, and where plant group p is in fuel region b and of coal-fired plant type C. The coefficient BREQ$_{psm}$ represents the consumption required for operating the plant in the given season and mode, in terms of consumption per unit of capacity. This coefficient is calculated in the model by multiplying the derating factor by the hours of operation (based on the mode of operation) and the heat rate of the plant. The derating factor adjusts the output for the assumed capacity factor in the operating mode, which accounts for forced outages as well as potential contributions to spinning reserves. The heat rate is also adjusted by a factor that is determined by mode of operation (see Appendix 4.D for detail)

Non-biomass dispatchable plant types:

$$(4\text{-}16) \quad -\sum_f BTU_{bDfj} + \sum_p \sum_m BREQ_{psm} \cdot OPBS_{psm} \ \leq \ 0$$

for every fuel region b, plant type D, and season s, and where plant group p is in fuel region b and of plant type D. The fuel consumption required is calculated as for coal-fired plants.

Biomass plants' constraints are as follows:

$$(4\text{-}17) \quad -BTU_{bB} + \sum_p \sum_s \sum_m BREQ_{psm} \cdot OPRNW_{psm} \leq 0$$

for every fuel region b, and biomass plant type B, and where plant group p is in fuel region b and of plant type B. The fuel consumption required (BREQ$_{psm}$) is calculated by the assumed capacity factor for the operating mode multiplied by the hours in the season, and by the heat rate of the plant.

Nuclear plants' constraints are as follows:

$$(4\text{-}18) \quad -BTUN + \sum_p \sum_s \sum_m BREQ_{psm} \cdot OPBS_{psm} \leq 0$$

where plant group p is a nuclear capacity type.

Nuclear plants are dispatched in the same manner as coal-fired plants, and the fuel consumption is calculated as described above.

Electricity load requirements. These constraints are specified by region, season, and load slice. Each load slice has a specific capacity and energy requirement. The energy requirement for a given load segment can be obtained by multiplying the capacity requirement (gigawatts) by the duration (hours) of that time period.

The load segments are defined by a combination of capacity requirements, time of day, and seasonal variations. The objective for the segment definitions is to be able to clearly map intermittent technologies (in other words, solar and wind) to the appropriate load segments while maintaining the overall regional load characteristics.

The energy requirements for each vertical segment can be satisfied by a number of different alternatives. First, the energy may be produced by operating dispatchable technologies in one or more capacity factor modes. For example, conventional coal steam capacity can be operated in base or intermediate modes. In base mode, one unit of capacity would contribute energy to all load segments. If the same capacity is operated in intermediate mode, it would not contribute to those load segments with lower capacity requirements. Distributed generation plants can also be used to meet load and are assumed to operate in limited modes defined by both a minimum and maximum capacity factor. The contribution of a dispatchable capacity type towards meeting the requirements for a given load segment is the product of the capacity assigned to operate in that slice (OPBS$_{psm}$ or OPDG$_{psm}$, where operating mode m includes load slice l) and the hours in the load slice. An additional requirement for spinning reserves is incorporated in the model, and this requires an expansion of the operating modes for most capacity types to represent alternate levels of commitment to meeting the load requirement versus the spinning reserve requirement. These modes are described in further detail in the following spinning reserve requirement section.

Second, capacity using renewable energy sources (excluding intermittent technologies) such as geothermal, biomass, or municipal waste contribute to load. These technologies are typically used to their full capability subject to energy resource constraints. However, these technologies are also given optional operating modes to provide varying levels of spinning reserves across time slices, similar to baseload fossil fuel and nuclear technologies. The contribution to load is the product of the capacity (OPRNW$_{psm}$) and the corresponding derate capacity factor multiplied by the hours in the time slice. For hydroelectric plants, the capacity constraint is converted to an energy constraint, and capacity

utilization (OPHYD$_{psl}$) is determined independently for each load segment. Each operate vector is bounded at the existing capacity.

The REStore Submodule provides the net availability by time slice for intermittent technologies so that the capacity factors used in EFD reflect any need for curtailment. REStore also determines the most economical times to charge and discharge the battery storage technology, and EFD uses the net capacity factors from this solution, which can be either positive or negative. Finally, load can be met by trade from surrounding regions (TREL$_{resl}$), including Canadian regions (TRCN$_{hqrsl}$).

When pumped storage or demand storage technologies are used to meet demand through the typical operate vectors, the generation/storage must be replaced. The amount of storage required (STX$_{rsl}$) is a negative contribution to the load requirement, effectively increasing the demand.

(4-19)

$$
\sum_p GEN_{psm} \cdot OPBS_{psm} + \sum_p GEN_{psm} \cdot OPRNW_{psm}
$$

$$
\sum_p GEN_{psl} \cdot OPIN_{psl} \pm \sum_p GEN_{psl} \cdot OPDS_{psl} + \sum_p GEN_{psl} \cdot OPHY_{psl}
$$

$$
+ \sum_p GEN_{psm} \cdot OPDG_{psm} - STX_{rsl} + \sum_{e \neq r} (1 - TLOSS) \cdot HRS_{sl} \cdot TREL_{resl}
$$

$$
- \sum_{g \neq r} HRS_{sl} \cdot TREL_{grsl} + \sum_h \sum_q (1 - TLOSS) \cdot HRS_{sl} \cdot TRCN_{hqrsl}
$$

$$
\geq LDREQ_{rsl}
$$

for every region r, season s, and load slice l where plant group p is in region r. For dispatchable and distributed generation plants, the operating mode, m, must include load slice l.

Spinning reserve requirements. These constraints are specified by region, season, and load slice. Each load slice has a specific amount of capacity that must be set aside for spinning reserves. This capacity must be committed to operate at some minimum level to meet the load requirements, but it must also have excess available to meet the spinning reserve requirement. The requirement is computed as a percentage of the load height of the slice plus a percentage of the distance between the load of the slice and the seasonal peak. These percentage parameters (SRRH$_r$ and SRRD$_r$) are specified by region. An additional reserve requirement is then added that is a percentage of the derated intermittent capacity in that time period to reflect the greater uncertainty associated with the availability of intermittent resources. These percentages (SRINT$_{ir}$) are input by region and intermittent plant type.

To satisfy these spinning reserve requirements, the operating modes for qualifying technologies were expanded and redefined. When dispatchable capacity is committed to at least a minimum level of generation in a time slice, it qualifies to satisfy spinning reserves equal to the excess capacity not generating (the difference between its rated output after outages and its generation level). If desired, the user can specify that only a fraction of the excess capacity qualifies for spinning reserves (SRCR$_c$). For

these technologies, three new operating modes are defined that express alternative combinations of providing electricity generation and spinning reserves. To the extent that the operating mode requires commitment to multiple load steps, the level of generation would naturally ramp up to serve the higher load requirement, but this generation level must be balanced against maintaining adequate spinning reserves in each load step. The idea is to create operating modes that allow each technology the ability to independently satisfy all spinning reserve requirements in each load slice served given sufficient capacity of this technology type. One operating mode maximizes electricity generation and minimizes spinning reserves. Another mode maximizes spinning reserves and minimizes electricity generation, while the third follows load and therefore provides a middle amount of each in the non-peak slices. Any linear combination of these modes can be selected for each group.

The capacity factors for the load following mode are based on the aggregated dispatch from the hourly REStore solution. Under conditions with relatively high solar or wind generation, the net load in each EFD time slice may reflect a different pattern than the total load by slice (that is, there will be less need for nuclear or fossil generation in the intermediate load slice, which often coincides with daytime hours, but increased generation requirement in the base load slice). This gives the EFD a dispatch option that takes into account the varying levels of intermittent generation. Battery storage can provide spinning reserves, based on the capacity available determined by the REStore Submodule, including the storage portion of solar PV hybrid capacity.

The spinning reserve requirement is in terms of capacity rather than energy (as the load requirement). The GEN/HRS terms represent the fraction of capacity that is committed to meeting load for each of the operate vectors. Therefore, the coefficient for the operate vector in the spinning reserve requirement is the amount remaining after meeting load (1-GEN/HRS) multiplied by the assumed credit for that plant type (SRCR$_c$). This credit is currently set to 0.0 for intermittent capacity types (other than PV battery hybrid) and distributed generation because these plant types are assumed not to supply spinning reserves. All other plant types have a credit of 1.0.

The constraint includes the potential contribution of imports/exports to count for or against the spinning reserve constraint, but in the current implementation the assumed credit for transfers (SRTC) is set to 0.0 so this option is not exercised.

(4-20)

$$
\begin{aligned}
&\sum_p SRCR_c \cdot (1 - GEN_{psm}/HRS_{sl}) \cdot OPBS_{psm} + \sum_p SRCR_c \cdot (1 - GEN_{psm}/HRS_{sl}) \cdot OPRNW_{psm} \\
&\quad - \sum_p SRINT_{ir} \cdot (GEN_{psl}/HRS_{sl}) \cdot OPIN_{psl} + \sum_{p=storage} SRCR_c \cdot SRDS_{rsl} \cdot OPIN_{psl} \\
&\qquad + \sum_{p=PVH} SRCR_c \cdot SRPVH_{rsl} \cdot OPIN_{psl} \\
&\qquad + \sum_{e<>r} (1 - TLOSS) \cdot SRE_{yersl} \cdot SRTC - \sum_{g<>r} SRE_{yrgsl} \cdot SRTC \\
&\geq SRRH \cdot (LDREQ_{rsl}/HRS_{sl}) + SRRD \cdot (Max(LDREQ_{rls}/HRS_{sl}) - LDREQ_{rls}/HRS_{sl})
\end{aligned}
$$

for every region r, season s, and load slice l, where plant group p is in region r. For dispatchable plants, the operating mode, m, must include load slice l.

Hydroelectric energy requirements. For hydroelectric plants, the operate variables are bounded by the total capacity of each plant, and the dispatch decision is made for each time slice independently. This process is used because the energy from hydro plants can be stored and used at the time it is most needed, within a given season. However, there is a limit to the total amount of energy that can be provided based on the individual plant's capacity factor. Therefore, a constraint for each hydro unit ensures that the plant is not producing more electricity than possible.

$$(4\text{-}21) \quad \sum_l GEN_{psl} \cdot OPHY_{psl} \le HYAVL_{ps}$$

for every hydro plant group p and season s. The term $HYAVL_{ps}$ is simply the capacity of the plant multiplied by the seasonal capacity factor. The same constraints are in place for existing pumped storage plants and demand storage capacity, limiting their output to the maximum capacity factor multiplied by the capacity available. However, storage technologies also have requirements to replace that generation in other time slices.

Storage requirements. For pumped storage and demand storage technologies, the generation they provide must be replaced in other time periods. A factor, $STFAC_i$, indicates the total amount of storage replacement needed. For traditional pumped storage capacity, this factor is assumed to be 1.20, requiring 20% more generation required to replace what is provided by the technology. For demand storage, a factor of 1.0 would be used to model simple load shifting, or a factor below 1.0 could be used to model peak-shaving, where some of the demand is simply reduced at peak and not used later. Currently, the demand storage factor is set to 0.96, assuming a small amount of peak-shaving but keeping overall demand fairly constant.

$$(4\text{-}22) \quad \sum_p \sum_l OPHY_{psl} \bullet STFAC_i \bullet GEN_{psl} - \sum_l STX_{yrsl} \le 0$$

for all plant types p that are of storage type i, in EMM region r, for each season s.

Interregional trade constraints. Total imports and exports to and from each region are imposed through these constraints. The limit on total imports/exports is set to 75% of the maximum import and export capability to the region. As discussed in the spinning reserve requirement section, the structure allows for spinning reserve capacity in one region to contribute to another region's constraint. If transfer capacity were chosen to be used for the spinning reserve constraint, then it would also be required to be within these regional limits.

The limits for exports are given by the following:

$$(4\text{-}23) \quad \sum_g TREL_{gesl} + \sum_g SRE_{gesl} \le EXP_{es}$$

for every export region e, season s, and load slice l.

The corresponding limit on imports is given by the following:

$$(4\text{-}24) \quad \sum_e TREL_{gesl} + \sum_e SRE_{gesl} \leq IMP_{gs}$$

for every import region g, season s, and load slice l. The individual decision variables TREL$_{gesl}$ represent the amount of trade from import region g to export region e and are bounded by the available transmission capacity between the two regions.

International trade constraints. EFD includes a supply curve of available capacity from the Canadian regions. This supply curve is developed outside of NEMS and read in from an input file. The supply curve lists the amount of capacity available for each load slice, at several cost steps, and for each Canadian region and model year. The imports chosen cannot exceed the amount available. The supply curve is given by the following:

$$(4\text{-}25) \quad \sum_r TRCN_{hqrsl} \leq CNAVL_{hqsl}$$

for every Canadian region h, supply step q, season s, and load slice l.

The amount of total imports between any Canadian region and EMM region is also constrained by the transmission capability available, as shown in the following:

$$(4\text{-}26) \quad \sum_q TRCN_{hqrsl} \leq TRAVL_{rhs}$$

for every electricity region r, Canadian region h, season s, and load slice l.

Planned maintenance requirements. These constraints ensure that the total of the seasonal planned maintenance scheduled for each plant group satisfies the annual maintenance requirements. These constraints are modeled at the plant group level to ensure that each unit is taken down for the correct amount of time, rather than let the model choose to take the most expensive plants down for longer periods to cover the requirement of a larger group.

$$(4\text{-}27) \quad \sum_s HOURS_s \cdot MB_{ps} \geq PMBR_p$$

for every plant group p, where HOURS$_s$ is the number of hours in the season s.

Capacity balance requirements. The capacity balance constraints ensure that the total capacity scheduled to operate plus the capacity scheduled to be down for maintenance does not exceed the total available capacity. The constraint is at the plant group level to accommodate both the scheduling of maintenance for each plant and the multiple operating modes to allow for meeting spinning reserves.

$$(4\text{-}28) \quad MB_{ps} + \sum_m OPBS_{pms} \leq CAPB_{ps}$$

for every plant group p and season s.

Must run constraints. Certain plants are considered must run, which means they will operate regardless of their operating costs. These plants are typically uneconomical when evaluated by the model, but they are consistently being put to use based on historical data. Their operation could be relieving transmission congestion that is not captured in the EMM, or their operation could be based on fixed contracts. The EFD attempts to capture this generation in an attempt to maintain historical patterns throughout the projection. In some cases (carbon constrained, for example), the model would turn off these must-run units and allow them to be retired, but in a Reference case, we assume they will continue to run at levels seen in the past. The constraint is modeled by individual plant group to ensure that the output from the must-run plants meets the historical generation based on the input capacity factor for each plant.

$$(4\text{-}29) \quad \sum_s \sum_m GEN_{psm} \cdot OPBS_{psm} \geq MRREQ_p$$

for every plant group p.

Emissions constraints. These constraints limit the emissions produced as a result of electricity generation. Emissions from SO_2, Hg, and CO_2 depend on the type of coal being used, as well as the configuration of the plant and amount of electricity produced. These emissions are constrained explicitly in the EFD based on the SO_2 content (SO_2C) of the coal transported for use in electric power plants (CT). NO_X emissions are based only on the design of the plant and do not vary between types of coal. ECP has already made the retrofit decisions necessary to meet the goals, so the EFD does not explicitly constrain the NOx emissions. Instead there is a row accumulating the NOx emissions and balancing it with a vector that incurs the cost of the NO_X penalty as determined by ECP. In this way, ECP passes the costs of compliance along to EFD, and this process does restrict the emissions to approximately the levels required. Although retrofit decisions for controlling CO_2 emissions are also determined in ECP, EFD does evaluate operating decisions to comply with any carbon constraints.

The CSAPR limits SO_2 and NO_X emissions from 27 states. Because EMM does not represent electricity markets at the state level, it represents the CSAPR SO_2 targets using coal regions, which are combinations of states. The individual state targets for the states within a particular coal region are summed. These regional targets can be met by reducing emissions from coal and oil plants within the region or by obtaining allowances from the other SO_2 region.

The CSAPR sulfur constraint is given by the following:

$$(4\text{-}30) \quad \sum_J \sum_C SO2C_{JNC} \cdot CT_{JNC} + \sum_{x \in N} SO2D_x \cdot RT_x + \sum_{u \neq N} MVSO2_{Nu} - \sum_{u \neq N} MVSO2_{uN} \leq SO2LIM_N$$

for every CSAPR (coal) region N.

The first term simply accumulates the emissions for all coal-fired plant types by multiplying the sulfur emission rate times the fuel consumption. Similarly, the second term multiplies the emission rate for residual fuel oil in oil steam plants by the corresponding fuel use. The two MVSO$_2$ terms represent trading SO$_2$ allowances between the two regions. The first one represents the allowances sold by region N to other regions, which count towards meeting the cap. The second MVSO$_2$ term permits coal region N to exceed its cap by the amount of allowances purchased from other regions.

The CSAPR limits the amount of allowances that can be purchased, which is represented as follows:

$$(4\text{-}31) \quad \sum_u MVSO2_{uN} \leq SO2V_N$$

for every CSAPR (coal) region N.

Mercury emissions caps are modeled in a similar manner. An additional difference is that mercury in coal-fired plants can also be reduced by injecting activated carbon. There is no national limit on mercury (HGLIM$_y$) so the following equation also simply accumulates mercury emissions without imposing a limit.

National mercury constraint is given by the following:

$$(4\text{-}32) \quad \sum_N \sum_J CTLHG_{JN} + \sum_c MERC_c - AVGHG \cdot TSTOCK \leq HGLIM - BNKHG$$

Plant type balancing row is given by the following:

$$(4\text{-}33) \quad -MERC_C + \sum_J \sum_N \sum_a HGC_{JNC} \cdot CT_{JNCa} \leq 0$$

for every dispatchable coal-fired plant type C.

Rather than imposing an emissions limit for mercury, the MATS specifies a required removal rate. ECP previously made planning decisions to retrofit or retire capacity so that the only plants remaining were those that could comply. Activated carbon injection may be necessary to meet the standards, depending on the plant configuration and type of coal used.

As discussed above, the NO$_X$ emissions are dependent on the plant type but not the specific coal used. Because EFD cannot make retrofit decisions, it does not include an explicit constraint limiting the NO$_X$ emissions. But NO$_X$ emissions are tabulated, and the NO$_X$ allowance price calculated in the ECP is passed through and included in the marginal cost of electricity generation.

Regional NO$_X$ constraint is given by the following:

$$(4\text{-}34) \quad \sum_c ELNOX_{cv} - ESCNOX_v \leq 0$$

for every NO$_X$ region v. The term ESCNOX$_v$ is typically a vector with a cost in the objective function equal to that of the NO$_X$ allowance price derived in the ECP.

The constraint is given by the following:

$$(4\text{-}35) \quad -ELNOX_{cv} + \sum_{p \in v} \sum_{s} \sum_{m} NOXC_p \cdot BTUREQ_{psm} \cdot OPBS_{psm} \leq 0$$

for every capacity type c and every NO$_X$ region v.

The Regional Greenhouse Gas Initiative (RGGI) specifies carbon emission limits (CARLIM$_{zy}$) for a collection of Northeastern states.

The regional carbon constraint is given by the following in Equation (4-40). If compliance becomes too costly, offsets (Off$_y$), cost containment reserve allowances (RSV$_y$), and emission containment reserve allowances (ECR$_y$) can be used instead of corresponding reduction in emissions:

(4-36)

$$\sum_{b \in z} \sum_{C} \sum_{f} CARC_{bCf} \cdot BTU_{bCf} + \sum_{b \in z} \sum_{D} \sum_{f} \sum_{j} CARD_{bDf} \cdot BTU_{bDfj} +$$

$$\sum_{b \in} \sum_{D} \sum_{f} CARO_{bDf} \cdot BTU_{bDf} - OFF_y - RSV_y - ECR_y \leq CARLIM_{zy}$$

for every carbon containment region z in year y. The first term of the equation represents the carbon emissions from coal-fired plants as it is the product of the carbon content (CARC$_{bCf}$) and the fuel consumed (BTU$_{bCf}$). Similarly, the second and third terms accumulate the corresponding emissions from plants using natural gas and oil, respectively.

Beginning with AEO2012, California AB398 resulted in an additional carbon containment area. This representation was updated for AEO2013 to enforce the overall cap and to account for emissions from other sectors, as well as a bank, offsets, and reserves, as described in the bill. EMM has incorporated the latest updates to the legislation, including an extension of the cap through 2030. Within the power sector, emissions associated with electricity imports (CIM$_z$) and plants owned by California suppliers but located out-of-state (COS$_z$) also count towards the cap. These respective terms are defined as follows:

$$(4\text{-}37) \quad CIM_z = \sum_{e} \sum_{s} \sum_{l} TREL_{zesl} \cdot HOURS_s \cdot CARIM_z$$

for the California carbon containment region z (also an EMM region g); and

$$(4\text{-}38) \quad COS_z = \sum_{p \notin z} \sum_{s} \sum_{m} GEN_{psm} \cdot 0.001 \cdot CAROS_z \cdot OPBS_{psm}$$

for the California carbon containment region z.

The power sector carbon emissions for California are accumulated in the following constraint:

(4-39)

$$-CARUTL + \sum_{b \in z} \sum_{C} \sum_{f} CARC_{bCf} \cdot BTU_{bCf} + \sum_{b \in z} \sum_{D} \sum_{f} \sum_{j} CARD_{bDf} \cdot BTU_{bDfj} +$$

$$\sum_{b \in z} \sum_{D} \sum_{f} CARO_{bDf} \cdot BTU_{bDf} + \sum_{e} CARIM_e \cdot FRMIMP_e + CIM_z + COS_z \leq 0$$

The overall carbon limit is enforced in the final constraint, accounting for emissions from industry (CARIND), refineries (CARREF), fuel providers (CARFUE) and other (CAROTH). The limit can also be met by using banked allowances (CARBNK) and reserve allowances (CARRSV) accumulated in previous years, or by using offsets (CAROFF), given by the following:

(4-40)
$$CARUTL + CARIND + CARREF + CARFUE + CAROTH -$$
$$CARBNK - CAROFF - CARRSV - CARLIM \leq 0$$

Calibration. The *Short-Term Energy Outlook* (STEO) provides power sector forecasts over the next year or two and therefore overlaps with the projection period of the *Annual Energy Outlook*. The EFD includes equations to insure consistency in fossil fuel generation and consumption between the STEO and the AEO. The objective of these constraints is to require the EMM results to match the corresponding STEO outputs, within a prespecified tolerance level.

Each EMM region has an equation, and the results are summed to determine the national-level totals. For coal-fired generation, calibration is achieved with the following two equations:

(4-41)
$$\sum_{p \notin r} \sum_{s} \sum_{m} GEN_{psm} \cdot 0.001 \cdot CLSHR_{bCf} \cdot OPBS_{psm} - CLGEN_r = 0$$

for every EMM region r.

(4-42) $\sum_{r} CLGEN_r - GENSC = 0$

Equation (4-41) accumulates the generation for each coal-fired plant p in a given region (CLGEN$_r$), accounting for the coal-fired fuel share defined by the plant's fuel region b, capacity type C, and fuel option f. Equation (4-42) then sums all of the regional coal-fired generation to achieve the national total. GENSC is a bounded variable in which the midpoint of the interval is the total coal generation from the STEO and the lower and upper bounds differ from this midpoint by the tolerance level so that the total coal-fired generation determined by the EMM falls within this range for the corresponding result from the STEO.

Similar equations are also included to calibrate to the STEO forecast for natural gas-fired generation (GENSG) by accumulating the generation for each natural gas-fired plant p in a given region (NGGEN$_r$), accounting for the natural gas-fired fuel share defined by the plant's fuel region b, capacity type C, and fuel option f (NGSHR$_{bCf}$).

For coal, Equation (4-43) accumulates coal consumption for each EMM region (CLCON$_r$). Equation (4-44) sums the regional quantities to determine the national total, which is calibrated to the STEO coal

consumption (CONSC). Again, consistent equations for calibrating natural gas consumption are also included.

(4-43)

$$\sum_{p \notin r} \sum_{s} \sum_{m} BREQ_{psm} \cdot CLSHR_{bCf} \cdot OPBS_{psm} - CLCON_r = 0$$

for every EMM region r.

(4-44) $\sum_r CLCON_r - CONSC = 0$

Representation of Power Plant Captured CO₂. The Carbon Capture, Allocation, Transportation, and Sequestration (CCATS) module in NEMS represents the market for CO_2. It is an optimization model that minimizes the costs of transporting and sequestering or utilizing CO_2 and determines the most cost-effective network flow of CO_2 from supply sources to demand locations, including both EOR sites and saline storage. Currently, tax subsidies are available for plants that start construction or begin a retrofit before 2033 and are applied to the first 12 years of operation. The EFD tracks what plant groups are eligible for a tax credit in any given year and the CCATS module provides two sets of prices (CNTX$_O$, CNTS$_O$), based on whether the plant is receiving subsidies or not.

By convention, biomass combustion is assumed to result in net-zero CO_2 emissions. However, for the biomass energy with carbon capture (BECC) technology, the emissions released during combustion are captured, and an emission rate (CO2B) must be assumed to be able to calculate the amount of CO_2 captured, and this technology will end up with a negative contribution to overall emissions.

CO_2 that is captured from power plants in each fuel region R that includes Census Division O must either be sent to EOR or saline injection, so this is modeled as an equality constraint, so the cost of every ton captured is included in the objective function. The EFD represents two parallel sets of constraints depending on whether the plant is eligible for the tax credit or not, so that the appropriate cost is applied.

(4-45)

$$\sum_{p=coal} \sum_{s} \sum_{m} CARR_c \cdot CO2C \cdot BREQ_{psm} \cdot OPBS_{psm}$$
$$+ \sum_{p=natural\ gas} \sum_{s} \sum_{m} CARR_c \cdot CO2D \cdot BREQ_{psm} \cdot OPBS_{psm}$$
$$+ \sum_{p=BECC} \sum_{s} \sum_{m} CARR_c \cdot CO2B \cdot BREQ_{psm} \cdot OPRNW_{psm} - NTX_O = 0$$

For every Census division O, where plant p is in region O and plant p is not eligible for a tax subsidy.

(4-46)

$$\sum_{p=coal} \sum_{s} \sum_{m} CARR_c \cdot CO2C \cdot BREQ_{psm} \cdot OPBS_{psm}$$

$$+ \sum_{p=natural\ gas} \sum_{s} \sum_{m} CARR_c \cdot CO2D \cdot BREQ_{psm} \cdot OPBS_{psm}$$

$$+ \sum_{p=BECC} \sum_{s} \sum_{m} CARR_c \cdot CO2B \cdot BREQ_{psm} \cdot OPRNW_{psm} - NTS_O = 0$$

For every Census division O, where plant p is in region O and plant p is eligible for a tax subsidy.

Appendix 4.A. EFD Data Flows

The electricity fuel dispatch (EFD) is run for each year and iteration of the National Energy Modeling System (NEMS), as long as the Electricity Market Module (EMM) model is selected to be run. EMM often makes use of direct access files (DAFs) to store data that is passed back and forth between submodules or is accessed several times during a run. Many of the subroutine calls in the EFD simply involve retrieving or storing variables that are needed at different times during the simulation, and these subroutine calls are not detailed here. The control module of the EFD is the subroutine *ELEFD*. Subroutine *ELEFD* initializes variables and reads in necessary data and then calls *ELDISP*, which does additional initializations and creates an ordered list of plants for each region. Next, the subroutine ED$GRP loops through the individual plant records and does aggregation to larger plant groups that are used within the EFD. The grouping tolerances can be set by the user to control the level of aggregation, keeping in mind that the model size will affect run time. *ELEFD* next calls *EFD_LP*, which creates or revises the linear programming (LP) matrix, solves the LP, and retrieves the solutions, which is all done within the AIMMS software in the AEO2025 version of the model. Fuel consumption, generation, and emissions are accumulated during the solution retrievals. *ELEFD* then calls subroutine *ELRPSCR*, which calculates the costs of renewable credits for each region when a national or regional renewable portfolio standard is in place (not currently used by EIA). The final subroutine call simply creates reports used in analysis. The remainder of this section describes each of the major subroutines in more detail.

EFD begins by reading information on firm trades and the transmission constraints for economy interregional trade. The heights of the demand segments are adjusted to account for firm trades. Subroutine *ELDISP* is then called, which initializes variables and then calls the subroutine *ELMRIT*, which determines a merit order by listing the plant groups in order of increasing operating costs. Since the implementation of the LP, this step is not necessary for the simulation but is useful because it creates an ordered list of plants, and the sorted group numbers are used elsewhere in the model for storing results. Before the merit order is determined, the fuel shares used by each plant are determined. Subroutine *ELFSHR* calculates the fuel shares for dual-fired units based on the relative costs of the fuels. The fuel shares at this point are just approximations based on relative fuel prices to provide an initial ordering based on total costs. The final fuel shares are now determined by the LP.

The final subroutine called by *ELDISP*, within the seasonal loop, is *ELFACT*, which determines the load factors needed to calculate unit-specific derate factors. After the peak slice, units need to lower operating levels to simulate off-peak times and avoid shutting off and restarting plants. Load-following factors are determined by first calculating the area on top of the load curve. Plants are assigned factors depending on unit size, type of capacity, and proportion of time left in declining slices. With the introduction of the spinning reserve constraint, additional operating modes have been introduced that may result in derates other than this originally calculated factor being used.

Once *ELDISP* is completed, the model calls the subroutine to process the LP, *EFD_LP*. The code checks various switches that indicate whether the model coefficients and solution should be processed using the Fortran subroutines, or AIMMS. Currently, EIA uses only AIMMS for the EFD. A text file is used to

pass AIMMS any needed variables from the rest of EMM and NEMS, and AIMMS is launched. The EFD coefficients are derived within the AIMMS code, the model is solved, and any necessary outputs that are needed based on the EFD solution are calculated in AIMMS and passed back to NEMS through a text file. Some additional aggregation and filling of output variables occurs in Fortran, but the majority of the previous code is bypassed.

These routines remain in the EFD Fortran code, but are not processed given the input settings used by EIA. Within the AIMMS project, there are code sections or procedures that are identified by the old Fortran subroutine names, so this remaining section may still be useful to identify where certain calculations take place.

ED$BTU sets up the fuel consumption columns and consumption balancing rows. Vectors are created for fossil fuel consumption by fuel region, fuel type, plant type, and operating mode. For dual-fired plant types, the operating modes are determined based on the minimum and maximum fuel shares possible, based on aggregations of plant-specific data from the EMM plant file. Vectors are also created for nuclear consumption so that the nuclear fuel costs can be included in the objective function.

ED$TRADE sets up the transmission network to allow simulation of economy trading. Vectors for trade between regions are set up and bounded by the available transmission capacity. Constraints are also imposed on the total amount of imports and exports for each region. Available Canadian supply is modeled based on exogenous supply steps.

The next set of matrix revision subroutines are called for each EMM region:

ED$PM enforces the planned maintenance requirements by region and either plant type or individual plant group to ensure that the required amount of annual maintenance is imposed.

ED$LOAD sets up the demand requirements for each region, season, and load slice. The total demand for each region represents the total demand on the grid as well as generation for own use by nonutilities and cogenerators. The contribution from traditional cogenerators is represented with a fixed vector based on the levels provided from the demand models. This subroutine also sets up the spinning reserve requirements for each region, season, and load slice.

ED$RNW sets up the energy balance rows for hydro and storage technologies. The output of these technologies is bounded by their capacity multiplied by their seasonal capacity factors.

ED$BENCH sets up the rows to calibrate fossil fuel generation and consumption.

ED$OP sets up the vectors to determine the dispatch of each plant group. Based on the operating type assigned to the plant group, one of the following subroutines is called: *OPBSLD*, *OPRNBS*, *OPHYD*, *OPINT*, *OPDG*, or *OPSTR*. *OPBSLD* is used for all fossil fuel and nuclear plants. The model loops over the possible operating modes based on the minimum capacity factor, keeping the plants from operating only in peak slices where appropriate for certain plant types. *OPRNBS* is used for renewable plants that operate in a baseload manner, such as biomass and geothermal. *OPHYD* is used for hydro dispatch and assumes hydro can be used in any time slice within a season, up to a maximum energy output. *OPINT* is used for intermittent technologies, where the potential output for each time slice is based on varying capacity

factors as a result of different availabilities based on time of day. These availabilities are determined by the REStore submodule (see Appendix 3D). *OPDG* is used for grid-connected distributed generation technologies, where the appropriate operating modes are determined based on assumed minimum and maximum capacity factors. Finally, *OPSTR* is used for dispatching battery storage technologies. Operation of the battery storage capacity is determined in REStore, and the net impact of charging and discharging is aggregated to the EFD time slices and imposed as a fixed contribution or decrement to the time slice load. For all plant types that can contribute to the spinning reserves requirement, the corresponding operating subroutines include the setting up of different modes to supply varying levels of output toward load versus spinning reserves. The subroutine *OPINT* accounts for any additional spinning reserves required based on the level of intermittent generation.

ED$CAR sets up carbon constraints, as specified in the input assumptions. An explicit national-level emission limit can be set up for EFD (although this limit is not typically used), or regional constraints can be specified.

The next set of subroutines set up the fuel supply curves:

ED$COL sets up the coal supply submatrix. It uses information from the Coal Market Module (CMM) to describe production and transportation costs, available supplies, and coal characteristics such as Btu content and emissions rates for SO_2, NO_X, Hg, and CO_2. It also sets up the sulfur and mercury emissions constraints.

ED$GAS sets up the natural gas supply curves, in the same fashion as used in the electricity capacity planning (ECP).

ED$HYDROGEN sets up the hydrogen supply curves, using supply steps passed from the Hydrogen Market Module (HMM).

ED$OIL sets up the oil supply curves, again using the same methodology as in ECP.

ED$BIO sets up the biomass fuel supply curves, using the exogenous supply steps from the Renewable Fuels Module (RFM). Other uses of biomass such as ethanol and industrial use are accounted for because they all must come from the same supply.

The following subroutines were used to retrieve the solution, but currently are bypassed and now reside in the AIMMS project code.

EDO$BTU retrieves information from the fuel consumption balancing rows. The retrievals indicate the fuel shares chosen by the LP by plant type and region and determine the fuel consumption.

EDO$COL retrieves information from the SO_2 rows to update average emission rates.

EDO$BIO retrieves the reduced cost of the biomass supply rows so that the marginal biomass prices in each region are stored for reporting.

EDO$MRUN retrieves the reduced cost of the must-run rows so that the costs of operating the must-run plants can be captured in the competitively priced regions.

EDO$CCAP retrieves information from the carbon sequestration constraint to account for the net cost or revenue from sending captured CO_2 to EOR or saline storage.

EDO$PM retrieves the planned maintenance decisions and stores the available capacity and capacity out for planned maintenance for each plant group and season.

EDO$LOAD retrieves the reduced cost of the load row, which is the marginal energy cost used by the pricing model.

EDO$OP retrieves the dispatch decisions for each plant group and stores the generation by plant and load slice.

Once the solution details are retrieved, the subroutine *ELCOST* is called to aggregate the results for output reports and other model use (this post-processing routine remains in Fortran). The fuel consumption, generation, emissions, and costs (operating and fuel) are aggregated by region, owner, and plant type. The subroutine *ELDGNO* fills in the same output as *ELCOST* for distributed generation plants, while the subroutine *ELRNEWO* fills in the information for renewables.

Once the model completes the *EFD_LP* subroutine, *ELRPSCR* is called to simulate the renewable credit trading. This step is only necessary when a national renewable portfolio standard (RPS) is in place, but is not in the current Reference case. If there is an RPS, then this subroutine calculates the renewable share (as defined in the particular standard) for each region and determines how many credits it has either bought or sold. These costs or revenues are stored for use in the regulated pricing of electricity.

The final subroutine of the EFD, *DEBUG*, is simply used to create reports and fill in the EMM database.

Appendix 4.B. Data Sources

This appendix provides a list of the data sources in the electricity fuel dispatch (EFD). Each data source is accompanied by a brief description.

Survey forms

Form EIA-860, Annual Electric Generator Report

Form EIA-860 collects data on the status of existing electric-generating plants and associated equipment (including generators, boilers, cooling systems, and flue gas desulfurization systems) in the United States, as well as those scheduled for initial commercial operation within 10 years of the reporting period. The data are disseminated in various EIA information products. The data are used by public and private analysts to monitor the current status and trends in the electric power industry and to evaluate the future of the industry. Form EIA-860 is completed for all electric-generating plants that have or will have a nameplate rating of 1 megawatt (1,000 kilowatts) or more and are operating or plan to be operating within 10 years of the reporting period.

Form EIA-860M, Monthly Update to the Annual Electric Generator Report

Form EIA-860M covers the same respondents as the annual report and collects data on the status of proposed new generators scheduled to begin commercial operation within the next 12 months, existing generators scheduled to retire in the next 12 months, and existing generators that have proposed modifications scheduled for completion within 1 month.

Form EIA-923, Power Plant Operations Report

Form EIA-923 collects information from electric power plants and combined-heat-and-power (CHP) plants in the United States.

The form EIA-923 includes following data components:

- Electric power generation
- Fuel consumption
- Fossil fuel stocks
- Delivered fossil fuel costs
- Combustion byproducts
- Operational cooling water data
- Operational data for NO_X, SO_2, and particulate matter control equipment

These data are used to monitor the status and trends of the electric power industry and appear in many EIA publications. The Form EIA-923 is completed by all electric power plants and CHP plants that have a total generator nameplate capacity of 1 megawatt or greater.

FERC Form 1, Annual Report of Major Electric Utility

Federal Energy Regulatory Commission Form 1 is a mandatory, annual census of major investor-owned electric utilities that meet specified criteria for sales. The form collects data on income and earnings,

taxes, depreciation and amortization, salaries and wages, operating revenues, and operations and maintenance expenses.

U.S. Environmental Protection Agency—Emissions monitoring

The U.S. Environmental Protection Agency (EPA) uses the Continuous Emissions Monitoring System (CEMS) to ensure that the mandated reductions of SO_2 and NO_X under the Acid Rain Program are achieved. CEMS tracks the continuous measurement of pollutants emitted into the atmosphere in exhaust gases from combustion or industrial processes. Annual emissions for each unit are reported, and average emission rates are calculated for each plant for use in the EFD.

National Renewable Energy Laboratory

Regional Energy Deployment System (ReEDS) Model

ReEDS is a capacity planning and dispatch model for the U.S. electricity system and the source code and inputs are publicly available. EIA uses the ReEDS input data on transmission capacity to develop the interregional transmission capacity assumptions in the EMM.

Appendix 4.C. Adjustments to Heat Rates by Operating Mode

The purpose of these adjustments to the NEMS Electricity Market Model (EMM) heat rates is to represent the variability of power plant heat rates associated with differing levels of operations. With low natural gas prices and a rising share of intermittent renewable energy generation sources, coal-fired plant operations have been shifting from baseload to greater cycling and provision of operating reserves. These adjustments are designed to reflect in EMM the potential impacts of this modal shift on coal-fired plant heat rates and resulting costs, operation, and fuel consumption.

New variables for the heat rate adjustment parameters were added to the emmcnlt.txt input file. These variables identify which ECP plant types are included in the heat rate adjustment algorithm and include the parameters relating to the heat rate adjustments by capacity factor for each ECP type in each fuel region. These adjustments are expressed in piecewise linear form using between 3 and 11 steps.

The heat rate adjustment factors are first used to normalize the average heat rates in the plant file to derive the expected efficiency at full load for each unit using the historical average heat rates and capacity factors.

Key Equations:

The maximum efficiency adjustment factor for each ECP type and fuel region is set by the value of the last step of the input data. This maximum factor is defined as 1.000.

$$Max\_EFF = FLRG\_HR\_EFF_{RGN,T,STP=last}$$

where

$FLRG\_HR\_EFF_{RGN,T,STP=last}$
$= the\ efficiency\ adjustment\ factor\ for\ ECP\ type\ T\ in\ fuel\ region\ RGN, and\ last\ step\ of\ piecewise\ linear\ form\ of\ heat\ rate\ adjustments.$

At the low end of the curve, the efficiency adjustment factor is set to be equal to the first value of the curve if the capacity factor is less than or equal to the first step. In other words, the first step defines the lowest adjustment factor or worst heat rate.

For all other capacity factors or load levels, an interpolation is performed between the relevant steps of the curve. For each step level,

$$LL = FLRG\_HR\_LL_{RGN,T,STP-1}$$

$$EL = FLRG\_HR\_EFF_{RGN,T,STP-1}$$

$$LH = FLRG\_HR\_LL_{RGN,T,STP}$$

$$EH = FLRG\_HR\_EFF_{RGN,T,STP}$$

$$Target\_EFF = EL + \left(\frac{EH - EL}{LH - LL}\right) * (Load\_Level - LL)$$

where

$FLRG\_HR\_LL_{RGN,T,STP} = the\ load\ level\ for\ ECP\ type\ T\ in\ fuel\ region\ RGN, and\ step\ STP$

$FLRG\_HR\_EFF_{RGN,T,STP} = the\ efficiency\ for\ ECP\ type\ T\ in\ fuel\ region\ RGN, and\ step\ STP$

The final heat rate adjustment is the ratio of the maximum and the target efficiencies.

$$HTRT\_ADJ = \frac{Max\_EFF}{Target\_EFF}$$

In both ECP and EFD, the heat rate adjustment factors are used to assign an associated heat rate to each operate option representing a different duty cycle. This feature could be implemented for all dispatchable plant types but is currently only used for coal-fired generating plants.

Coal-fired generating plants currently have six duty cycles for each of three seasons. The six duty cycles consist of three operating modes: maximizing electricity production, maximizing spinning reserves, and load following. The three operating modes are then expanded by the duration of service. For coal-fired generator units, capacity can be operated in all three load slices, or it can be operated for the peak slice and the intermediate slice. Note that if the number of seasons or slices per season changes, the number of duty cycles would also change. The data analysis suggested that heat rate loading penalties do not vary significantly by season, so the same heat rate penalties are used in each season. The penalties are multipliers to the normalized plant file heat rates. The penalty parameters by aggregate ECP type are used to assign a penalty factor for each operating mode. For the two modes at full loading, the multiplier is 1.0 (in other words, no penalty). For the other modes of operation across all three time slices, the average capacity factor in each slice determines its efficiency penalty based on the adjustment parameters. A greater penalty is assessed for capacity operating in only two time slices because plant shutdowns and startups are implied. The average seasonal rate is used to compute the penalty.

Reporting

Unit-level heat rate data are reported in the DPGDT table in the EMMDB.MDB output file. Before the variable heat rate modifications were introduced, these average rates were computed as the ratio of the total generation across operating modes within the LP, and the consumption was computed using the average heat rate for each unit. Now that heat rates in the model vary by duty cycle as well as generation, the calculation of consumption is pushed back to the routine that queries the LP.

5. Electricity Finance and Pricing Submodule

Model purpose

The Electricity Finance and Pricing Submodule (EFP) is a component of the Electricity Market Module (EMM), which is part of the National Energy Modeling System (NEMS). As a component of NEMS, EFP projects financial information for electric utilities on an annual basis given a set of inputs and assumptions concerning projected capacity expansion plans, operating costs, regulatory environment, and financial data. The outputs of the model include electricity prices by end-use sectors for North American Electric Reliability Corporation (NERC) and census regions, financial statements, revenue requirements,[46] and financial ratios for each stage of production (generation, transmission, and distribution). Electricity prices are projected for regulated, competitive, and mixed regions. Regulated prices are determined by allocating projected revenue requirements to each customer class and dividing by the corresponding sales. Because EFP is an aggregated model, the revenue requirements are allocated according to a representative rate structure for an entire region. EFP simulates the traditional cost of service or rate of return regulatory method where electric utilities have their rates set by local, state, and federal regulatory commissions. Rates for utilities are set to allow them to recover their capital and operating costs and earn a rate of return. Revenues required for wholesale trades, including generation that is provided by nonutilities,[47] are determined in separate submodules of EMM of NEMS and transferred to the EFP as expense items.

When calculating regulated prices, there are three exceptions to the use of traditional rate of return regulation for determining revenue requirements in EFP. These exceptions—sales-leaseback transactions,[48] phase-in plans for new generating units,[49] and disallowances[50]—are modeled by exogenously adjusting the projected revenue requirements to be consistent with known information. The revenue that the aggregated utility will actually receive is modeled by adjusting the revenue

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[46] Revenue requirements are the costs of generating and delivering electricity that a ratemaking authority allows a regulated utility to recover from ratepayers.

[47] Nonutility generators are companies that generate electric power to be sold at wholesale rates to utilities who will in turn sell the power to ultimate consumers. Nonutility generators are nonregulated in that ratemaking commissions generally do not use the exhaustive cost-based determination of electricity rates that are used for traditional regulated utilities. Instead, alternative methods for setting their rates have been developed such as a utility avoided cost method for cogenerators, and competitive bidding for independent power producers (IPPs).

[48] A sales-leaseback transaction in the electric power industry generally involves the sale by the utility of a newly completed power plant to a group of investors with the understanding that the utility will then operate the plant through a lease arrangement. The advantage to the utility of such an arrangement is that rate shock can be avoided because there is a quick recovery of the costs of building the plant (through the sale proceeds). Payments by the utility for the use of the plant may then be levelized by the lease payments.

[49] A phase-in plan also serves to reduce rate shock caused by a new plant entering service. A new plant is introduced into rates in phases to raise rates gradually over time. In many cases, the ratemaking authority will allow the utility to earn a compounded return on the unrecovered portion of the plant, but recovery of these returns is deferred until a later date as part of the phase-in plan.

[50] A disallowance occurs when a ratemaking authority refuses to allow a utility to recover the costs of building a plant or a portion of a plant through the rates it charges consumers. Grounds for a disallowance could be that the utility has built more generating capacity than it needs, or the ratemaking authority judges that the utility's management was imprudent in some aspect of the manner in which the building project was undertaken.

requirement by a function to simulate regulatory lag.[51] The model solves for internal cash flow and determines the external financing needed to meet capital expenditures.

Revenue requirements are allocated to each of four customer classes: residential, commercial, industrial, and transportation. The allocation process is carried out in three steps. First, all costs are functionalized. That is, they are sorted by stage of production into generation, transmission, and distribution. Second, the functionalized costs are classified according to the service characteristics to which they are related. The four service characteristics are fuel costs, variable operation and maintenance (O&M) costs, fixed O&M costs, and capital-related costs.[52] Third, these functionalized and classified costs are allocated to the four customer classes, and the average revenue for each customer class in each region is determined. In addition to determining average revenues by customer class and region, the EFP builds financial statements and ratios using accounting methods that simulate standard industry accounting practice.

Although the Transportation Demand Module (TDM) within NEMS projects the growth in electric vehicle (EV) sales and associated fuel consumption, the electricity demand for EV charging within the EMM is accounted for in the sector where the charging occurs – either residential or commercial. The TDM provides the EMM with demand broken down by charging location and vehicle type, so that appropriate load shapes can be applied in ELD and so the EFP can attribute the costs to the appropriate end-use sector.

Prices in the generation sector in some regions of the country reflect a competitive market rather than traditional rate-of-return regulation. For these regions, competitive prices are projected by calculating the marginal cost of the generation dispatched for each of the time slices in the EFD. The capital and maintenance cost of additional generating capacity needed to ensure system reliability is added to the marginal cost of electricity generation.

A region's electricity price is based on the average regulated prices and competitive prices within the region, weighted by the respective regulated and competitive electricity sales in the region. Alternative regulatory and financial treatments that can be simulated in EFP are flow-through versus normalized accounting,[53] construction work in progress (CWIP) versus allowance for funds used during construction (AFUDC),[54] alternative levels of allowed rates of return, and varying periods of regulatory lag.

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[51] Regulatory lag is the effect that is caused by any time-related deviation in the assumptions that underlie the calculations of electricity prices, such as the differences between forecast electricity sales and actual sales. The time variable in the EFP controls the period of time that passes before the realization of the change in assumptions.

[52] Capital-related costs include all costs of production other than operation and maintenance (O&M, including fuel) and all wholesale trade expenses. The return on the ratebase, annual depreciation expenses, and all taxes are three examples of capital-related costs.

[53] In flow-through accounting, the tax advantages of accelerated depreciation and investment tax credits are passed on directly to ratepayers by way of a reduction in the regulated utility's revenue requirements. In normalized accounting, these tax advantages are amortized over a period of time—usually the useful life of the asset that generated the tax advantage.

[54] In the CWIP scenario, construction costs are added to the ratebase for an immediate return on investment as they are accrued. In the AFUDC scenario, construction costs are not added to the utility's ratebase until construction is completed and the new asset is operational. Financing costs are accrued in the AFUDC accounts and amortized over the life of the asset.

The type of ownership (investor-owned or public) of utilities is specified to allow for more precise historical data inputs, varying regulatory, financial, and accounting conditions between ownership types, as well as to allow for enhanced analysis flexibilities and capabilities.

Relationship to other models

Inputs

EFP is a submodule of NEMS and receives several inputs from other NEMS components (Figure 12). The capacity expansion plan is provided by the Electricity Capacity Planning (ECP) submodule. This plan includes the year the plant enters service, capacity (megawatts), and cost (dollars per kilowatt). EFP uses this information to calculate the cost of construction and to determine when and how these construction costs are incorporated into electricity rates.

EFP receives fuel and O&M costs from the Electricity Fuel Dispatch (EFD) Submodule and uses these data to calculate the revenues needed by electric utilities. The revenue requirements are used to calculate electricity prices to be charged to consumers. Each customer class's contribution to peak load comes from the Electricity Load and Demand (ELD) Submodule. EFP uses these data to allocate costs to customer classes for pricing retail electricity. The ELD also provides sector loads by time slice that are used to weight the marginal prices under competitive pricing.

Electricity annual demand projections come from the end-use sector demand modules. EFP uses electricity demand projections in its average revenue calculations.[55]

The amounts of power purchased from industrial and commercial cogeneration facilities and refineries (kilowatthours) and the amounts paid by utilities are passed to EFP from the EFD submodule. EFP includes this information in its average revenue calculations.

Information on firm interregional and international power transfers comes from the EFD submodule.

Interest rates on bonds rated AA are passed to the EFP submodule from the Macroeconomic Activity Module (MAM). These interest rates are used to determine the projected costs of capital in EFP.

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[55] To calculate average revenues, the EFP will calculate revenue requirements and divide the result by total sales in kilowatthours.

Figure 12. Input/output flows for the Electricity Finance and Pricing Submodule
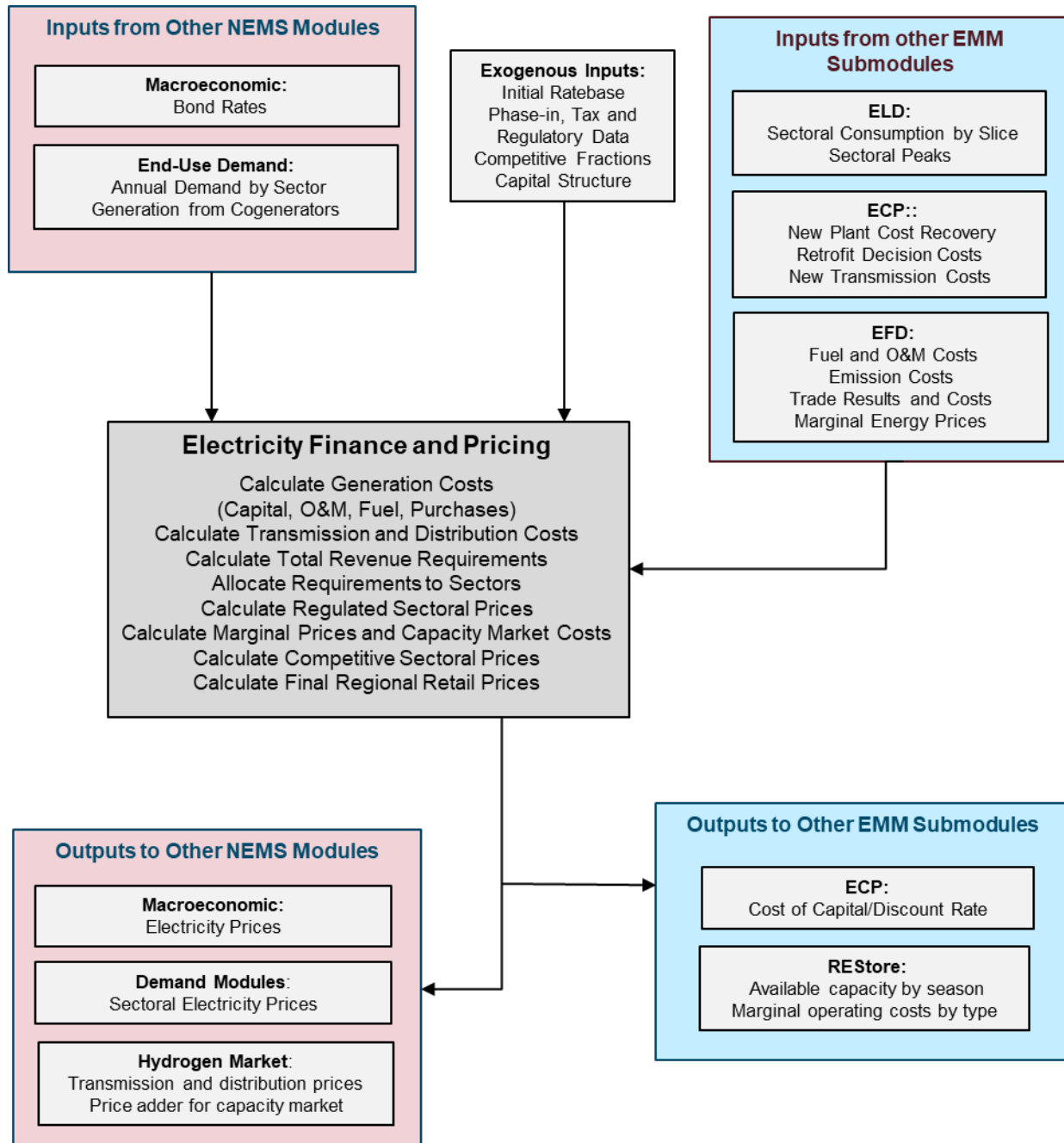
Outputs

EFP also passes several outputs to other NEMS components. Electricity price projections by customer class are passed to the electricity demand modules. The demand modules use this price information to calculate changes in the demand for electricity.

The utility cost of capital is used by the ECP submodule in its capital budgeting algorithm.

Model overview and rationale

Theoretical approach

EFP has four functions:

- Pricing electricity
- Generating financial statements
- Determining the cost of capital for electric utilities
- Determining the costs of transmission and distribution services

EFP is an accounting system that models regulatory practice and is completely deterministic. It has solution algorithms for the generation, transmission, and distribution stages of production. Pricing mechanisms are implemented for the generation and transmission stages of production to enhance the model's flexibility in simulating emerging pricing techniques used in the electric power industry. There are many pricing mechanisms that could be used for this purpose. The one that has been included initially in this submodule is the traditional cost-of-service method. The modular design of this submodule will allow the user to plug in additional pricing methods as they are needed in the future.

In those parts of the country that use market-based (not cost-of-service) regulatory structures in the electric power industry, EFP uses alternative algorithms to determine electricity prices. Algorithms to determine the generation component of prices for such regions have been developed. Both transmission and distribution (T&D) are considered to remain under rate-of-return regulation and revenue requirements and cost allocation are determined as under cost-of-service pricing.

The first step in calculating generation and transmission prices and distribution average revenues is to determine the revenue requirement. The revenue requirement (the costs that a ratemaking authority allows a regulated utility to recover from ratepayers) is the sum of the fixed and variable costs of production. The fixed costs include the return on the rate base, fixed O&M costs, and the annual depreciation expense (the recovery of invested capital). Revenue requirements are determined for generation, transmission, and distribution independently for each region. In the case of generation and transmission, the term revenue requirement is used loosely and is not meant to infer that these stages are assumed to be regulated under a cost of service arrangement in the future.

Fixed costs

The rate base is the total value (original cost less accumulated straight-line depreciation and excluded tax deferrals) of all capitalized assets on which the regulated utility is allowed by a ratemaking authority to earn a return. The rate base for the first modeled year is based on historical data with additions or

deletions determined by the modeled costs of capacity additions. Additions to the generation rate base are determined in the ECP submodule. Transmission rate base additions are determined in EFP as a function of regional non-coincidental peak usage, based on historical relationships between additions and peak usage—although extra transmission is added when necessary to prevent historical declines in transmission builds from resulting in a transmission infrastructure unable to accommodate increases in peak usage. Transmission additions are also determine in the ECP based on the projections to add new interregional capacity, and an adder to connect any new generating capacity to the grid. Additions to the distribution rate base are determined in EFP as a function of the regional non-coincident peak usage for distribution line infrastructure builds and as a function of sales for the customer account, services and sales portion of the distribution rate base. EFP also determines the fixed O&M for the three stages of production.

The projected rate of return is a function of the interest rate on AA-rated utility bonds. This rate of return is the weighted average cost of capital for each region. In the first year of the simulation, the long-term debt rate for each region is the weighted average of the actual long-term debt rates for electric utilities in that region. After that, it is a function of the national utility long-term debt rate (from the MAM). The regional cost of equity is a function of the previous year's regional return on equity and debt and the current year's regional debt rate. The cost of preferred stock is a function of the average of the regional debt rates.

Variable costs

Fuel costs and variable O&M for generation are determined by the Electricity Fuel Dispatch (EFD) Submodule. EFD also passes costs related to implementation of regulations, such as allowance costs for environmental rules, and sales and purchases of credits to meet renewable mandates. Transmission- and distribution-related variable O&M costs, along with other information needed for estimating revenue requirements, are determined in EFP based on historical data.

Cost allocation and retail average revenues

After the revenue requirements for all three stages of production have been aggregated, costs are allocated to the four customer classes. Costs are summed into four groups—capital related, fixed O&M, variable O&M, and fuel—for each stage of production for the purpose of allocation to customer classes. Several methods for allocating costs are available in the EFP. Users may choose the method used for each type of cost (capital, fixed O&M, variable O&M, and fuel) for each stage of production.

The selection of the method used for the allocation of each type of cost in each stage of production should result in costs being allocated according to which customer class is responsible for the cost of service. For example, some costs, such as variable O&M, can be confidently allocated on the basis of the level of electricity sales to each customer class. Other costs, such as fuel costs, are allocated on the basis of each customer class's contribution to the system peak load at the time of peak load (coincident peak method). The justification for these differences in allocation is that, for the purposes of allocating costs, it is assumed that electric utilities burn more expensive fuel as demand on the system increases. Therefore, the customer class most responsible for the system peak is most responsible for the burning of the most expensive fuels. Allocating fuel costs on the basis of the customer class's contribution to the peak load (using the coincident peak or probability of contribution to peak method) provides a method

that is consistent with that assumption. Other costs, such as the cost of building new generating plants, are incurred to meet peak load requirements as well as for fuel diversity and other reasons. Allocation methods that recognize the multiple reasons for these costs have been developed in the utility industry and are available in the EFP (two versions of the average and excess demand method).

The following are the cost allocation methods available in EFP:

Sales method. Costs are allocated on the basis of the proportion of electricity sales, in kilowatthours, to each of the four customer classes. This method will be used most frequently to allocate variable O&M costs for all three stages of production (generation, transmission, and distribution).

Coincident peak method. Costs are allocated on the basis of each customer class's contribution to the system peak at the time of the system peak.[56]

Probability of contribution to peak (PCP) method. The proportion of each class's load in each of the highest 20 peaking hours of each year (from the ELD submodule) is determined. Each customer class's proportions are averaged for each year and used as the weight for allocating costs. That is, costs are allocated on the basis of system peak data to time periods and customer classes.

Non-coincident peak (NCP) method. The residential, commercial, industrial, and transportation peaks are summed. Costs are allocated on the basis of the proportion of each customer class's individual peak load to the sum of the individual peak loads. This method will be used most frequently to allocate distribution fixed O&M and capital costs and will be used with the average and excess demand using probability of contribution to peak (AED-PCP) method (discussed below) to allocate transmission fixed O&M and capital costs.

Average and excess demand method using the probability of contribution to peak (AED-PCP) or coincident peak (AED-CP). This cost allocation method recognizes that capital additions are not made solely for peak demands. Sometimes capital additions are needed for fuel cost savings or other sales-oriented reasons. Customer class peaks and system load factors are both used in allocating costs. In this method, costs are first divided into those that will be allocated on the basis of average demand and those that will be allocated on the basis of excess or peak load demand. Those costs to be allocated on the basis of average demand are allocated first, which is done by calculating the ratio of the class average demand to the sums of the class average demands. Then, the remaining costs are allocated on the basis of the demand in excess of the system load factor. This process is done by calculating each customer class's contribution to the system peak using either the probability of contribution to peak method or the coincident peak method.

Retail electricity average revenues are calculated for each ownership type (investor-owned and public utilities) and across ownership categories (investor-owned and public utilities combined) for each EMM region and selected subregion. That is, each region will have an average revenue calculation for investor-owned utilities, public utilities, and a combination of the two. The calculation of average revenues for a given region and customer class is the revenue requirement that has been allocated to

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[56] The system, or coincidental peak, is the highest point on the system load curve. That is where the greatest demand on the system exists. Non-coincident peaks, on the other hand, are where individual customer class demands are greatest.

that customer class divided by the total sales (kilowatthours) to that customer class, given by the following:

$$\text{Average Revenue}_{ijy} = \text{Total Revenue}_{ijy}/\text{Sales}_{ijy},$$

where

$\text{Average Revenue}_{ijy}$ = average revenue (retail price per kilowatthour) of electricity for customer class i in region j for year y;

$\text{Total Revenue}_{ijy}$ = revenue requirement allocated to customer class i and region j for year y; and

Sales_{ijy} = sales (kilowatthours) to customer class i in region j for year y.

Stage of production and industry-wide financial statements are generated for each region and for the nation. Financial statements are standard accounting statements such as balance sheets and income statements. The industry-wide financial statements aggregate the three stages of production into a single set of financial statements to represent a vertically integrated industry.

Cost allocation under competition

In traditional cost-of-service regulation rates are set by regulators based on embedded costs (the average cost of producing electricity and serving the customer, including both short-run costs such as fuel and long-run costs such as plant and capital recovery). Because rates are set to cover all costs, including return on capital invested, this process is also referred to as rate-of-return regulation. Rates are generally set to reflect average costs rather than the more volatile fluctuations in marginal costs. Historically, given the large transaction costs associated with real-time pricing, average-cost pricing was seen as a way of ensuring revenues covered total cost.

In comparison, in competitive regions, the generation component of electricity prices is determined based on the average marginal cost of generation. Sector prices are based on the average marginal prices weighted by the demand of each end use throughout the year. Transmission and distribution prices are calculated as in traditional cost-of-service regulation in these regions.

Modeling renewable portfolio standards

One element of modeling the renewable portfolio standard (RPS) is calculating a credit price, that is, the marginal value of each kilowatthour of renewable generation. The credit price is calculated as follows. A levelized credit price, representing the marginal cost of compliance with the renewable portfolio standard, is calculated using output from the Electricity Capacity Planning Module for each of the years of the solution, derived as described above. Each such levelized credit price is weighted by the incremental change in renewable generation since the imposition of the portfolio standard to produce the annual credit price. It is assumed that the revenues (regional generation from qualified renewables multiplied by the credit price) from renewable credit trades are included in the revenue requirements. Credit sales reduce the revenue requirements and the resulting prices of electricity, whereas purchases increase revenue requirements and prices. In the competitive regions, the credit price is multiplied by

the appropriate RPS fraction (for example, 0.15 if the standard is set such that 15% of generation must be of the appropriate renewable type) and is added to the marginal energy cost.

The rationale is as follows. Assume that the RPS is set at 15% and that every generator must present 0.15 credits per kilowatthour of power sold, where a qualified renewable generator receives one credit for each kilowatthour sold. In this way, exactly 15% of the generation will be from the qualified renewable sources. The cost of purchasing 0.15 of a credit is a variable cost, and the cost of purchasing credits is then added directly to the marginal cost of generation.

Alternative approaches and reasons for selection
EFP, as the financial and electricity pricing component of EIA's intermediate-term energy modeling system, accounts for broad-based changes in the industry that are occurring or could occur in the next decade. One of the most impactful of these to the EFP is the shift in generation portfolios.

Shift in Generation Portfolios
Just as the 2000's saw increased investment in natural gas resources, the 2010s-2020s saw increasing investment in new sources of generation, especially wind, solar and battery storage. These are expected to continue into the future, though the policy environment may affect the extent of investment.

Although marginal electricity prices are non-zero for most hours, as the share of renewable generation with zero marginal cost increases, power costs may shift from being mostly fuel and other operational costs to being mostly capital costs. Traditional cost-of-service regulation will handle such a transition without trouble, but in areas with competitive markets for generation, this shift to zero marginal cost generation may require changes in market rules and pricing.

Solution algorithm and key computations
The purpose of this section is to describe the solution algorithm used within EFP. The discussion is organized into three parts, Sections 5.1, 5.2, and 5.3. Section 5.1, Projecting Revenue Requirements, describes the method used to project annual revenue requirements. To project the revenue requirement, one must first project the components of the rate base and the expenses. This part describes the algorithms used to calculate and forecast these items. All variables are either projected or input for each year and by type of plant ownership, either public or private. For convenience, subscripts denoting year and ownership type are assumed but not expressed in the equations, unless deemed necessary for clarity. Section 5.2, Competitive Pricing Algorithm, describes how to calculate and project competitive generation prices. With all of these items projected, one has nearly all the necessary components to project the financial statements and ratios. Section 5.3, Remaining Algorithms, describes the process of using these items to yield projections of electric revenue, prices, taxes (both actual and for financial purposes), and financial ratios.

5.1 Projecting Revenue Requirements
The EFP method of projecting revenue requirements simulates the outcomes of the regulatory process. The EFP projection of revenue requirements in any given year is that which allows the utilities to earn a rate of return equal to the cost of capital and also recover their operating costs. Formally, the projection for revenue requirements in any given year is given by the following:

$$(5.1\text{-}1) \qquad ERRVRQ = (ERRB \cdot ESRR) + ERTFLN + ERTOMN + ERBDE + GENREG$$
$$+ STAREG + FEDREG - EROFFS + ESLLP - EPIND + ERNDFPMT$$

where[57]

ERRVRQ	=	revenue requirement[58]
ERRB	=	rate base
ESRR	=	rate of return
ERTFLN	=	fuel costs
ERTOMN	=	operation and maintenance expenses, excluding fuel costs
ERBDE	=	book depreciation expense
GENREG	=	general taxes (gross receipts, property, sales) for regulatory purposes
STAREG	=	State income taxes for regulatory purposes
FEDREG	=	Federal income taxes for regulatory purposes
EROFFS	=	allowance for funds used during construction (AFUDC) offset
ESLLP	=	net lease payment associated with sales/leaseback transactions
EPIND	=	net deferred phase-in revenues for year
ERNDFPMT	=	nuclear decommissioning fund annual payment.

Note that, except where specifically stated, the variables are calculated in nominal dollars. Nominal dollars, rather than real dollars, are required to simulate the regulatory process effectively. Once nominal electricity prices are determined, they are reported in both nominal and real dollars. Each of the 12 variables on the right-hand side of the revenue requirement equation above is discussed in separate sections below. More detailed and involved discussions, beyond general explanations of a specific variable, are found in the appendix sections below, when needed to fully describe the solution algorithms.

Calculation of rate base (ERRB). The formula used to calculate the rate base is given by the following:

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[57] The variable names used in this description are the same as those found in the computer code of EFP. There are some conventions used in variable naming, as follows. A prefix of ER denotes variables containing results aggregated to the total system level. A prefix of ES denotes a ratio or fraction. A prefix of EO denotes variables related to assets existing before the first forecast year. Finally, a prefix of EB denotes a variable related to an individual plant build.

[58] For accounts that describe flows (for example, fuel expense, depreciation expense), the value refers to the period January 1 to December 31 of the given year. For accounts that describe stocks (for example, rate base, utility plant), except when otherwise stated, the value refers to the end of the given year value, in other words, value on December 31 of the given year.

(5.1-2)
$$ERRB = ERTUP + ERRCWP + ERWC + ERNFSN - ERABDE - ERPRDF$$
$$- (ERCNBV - ERCNAD) - ESLNDG - EDISNT$$

where

ERRB	=	rate base
ERTUP	=	total book value of utility plant assets
ERRCWP	=	Construction work in progress (CWIP) allowed in rate base
ERWC	=	working capital
ERNFSN	=	value of nuclear fuel stock
ERABDE	=	accumulated book depreciation
ERPRDF	=	Provision for deferred income taxes
ERCNBV	=	book value of canceled projects whose unamortized balance is not allowed in rate base
ERCNAD	=	accumulated depreciation (or amortization) of canceled projects whose unamortized balance is not allowed in rate base
ESLNDG	=	net deferred gain from sale/leaseback transactions
EDISNT	=	net value of disallowed plant assets.

All of the components of the rate base are calculated by utility ownership. As calculated above, ERRB is the year-end rate base. Another option in EFP is to calculate revenue requirements using the average value of the rate base over the year. The analyst may choose either option. The formulas used to calculate the average rate base are as follows:

(5.1-3)
$$ERRBA = (ERRB + ERRBB) / 2$$

(5.1-4)
$$ERRBB = ERRB_{(y-1)} + ERDLRB$$

where

ERRBA	=	average year rate base
ERRB	=	end of year rate base
ERRBB	=	beginning year rate base
ERRB$_{y-1}$	=	end of year rate base from proceeding year

ERDLRB = book value of new plants that come online this year.

The average-year rate base is calculated as the simple average of the beginning-of-year and end-of-year rate base. The beginning-of-year rate base is calculated as the rate base at the end of the previous year plus the book value of any new plants that come online in the given year. The calculation of the book value of new assets is described below.

When the end-of-year rate base option is chosen, an additional adjustment to the calculation of rate base is made. When plants come online in the middle of a given year, they continue to accrue allowance for funds used during construction (AFUDC) for those months before the plant is actually in service. To avoid earning an excess return (AFUDC plus a full-year cash return) on such plants, the end-of-year rate base is lowered so that the total return (AFUDC plus cash return) on the plant is appropriate. Further discussion of AFUDC is found in Appendix 5.B.

Total value of utility plant assets (ERTUP). Total Value of Utility Plant Assets (ERTUP) is calculated as follows:

(5.1-5)

$$ERTUP = \sum_k (EOBKVL_k) + \sum_k (ERBVYE_k) - ERBTIR$$

where

ERTUP = total utility plant

$EOBKVL_k$ = book value of assets existing in the base year (old assets) of type k (in other words, distribution)

$ERBVYE_k$ = book value of assets completed in the projection horizon (new assets) of type k that are completed as of the year of projection

ERBTIR = book value of all assets that have been retired during the projection horizon as of the year of projection.

The book value of existing assets in the base year is an input that can be derived from historical financial statements such as the FERC Form 1 or Form EIA-412. $ERBVYE_k$ is calculated by summing the book values of each individual new asset of type k, which is completed as of the year of projection. The calculation of the book value of individual new assets is also discussed below.

Construction work in progress (CWIP) allowed in rate base (ERRCWP):

Construction work in progress (CWIP) allowed in rate base (ERRCWP) is calculated as follows:

(5.1-6)

$$ERRCWP_y = EBRCWP_y + ERRCWP_{(y-1)}$$

where

$ERRCWP_y$ = CWIP allowed in rate base

EBRCWP$_y$ = CWIP allowed in rate base by new build, year y

ERRCWP$_{(y-1)}$ = CWIP allowed in this year's rate base from previous year's build based on last year's output.

For a more detailed discussion of CWIP, see Appendix 5.B.

Working capital (ERWC). Working capital is calculated within EFP using what is known as the one-eighth method. In general, this method arrives at working capital by summing the following: materials and supplies excluding fuel stocks; a percentage of operating and maintenance expenses, usually 1/8, representing a 45-day net lag in revenues and expenses; and other adjustments unique to a jurisdiction. The 1/8 method is based on the assumption that an average monthly billing utility has a net lag of 45 days between the payment of expenses and collection of revenues. This method of estimating working capital does have some drawbacks. The implicit assumption behind the 1/8 method is that there is a positive working capital need. The 1/8 method does not give any recognition to the availability of working capital resulting from the accrual of interest or tax expenses before the time of their payment. Items such as these constitute sources of working capital that are not considered using the 1/8 method. In addition, under circumstances of unusually fast receipt of customer payments and extended delay in paying suppliers, there can actually be a negative working capital requirement for a utility. The 1/8 method also assumes that all utilities have the same experience with regard to receipt of payment from customers and employ the same payment policies.

The calculation for working capital is given as follows:

(5.1-7)
$$ERWC = \frac{ERTOMN + ERTFLN}{8}$$

where

ERWC = working capital

ERTOMN = operation and maintenance costs, excluding fuel

ERTFLN = fuel costs

The calculation of ERTOMN and ERTFLN is discussed below.

Nominal value of nuclear fuel stock (ERNFSN). The nuclear fuel stock in any given year is calculated as a function of the amount of fuel actually used in the year, and is calculated as follows:

(5.1-8)
$$ERNFSN = 3.5 \cdot EFPNUC \cdot ESGNPD$$

where

ERNFSN = Nominal dollar nuclear fuel stock

EFPNUC = Real dollar nuclear fuel expense

ESGNPD = Inflation index to convert real dollars to nominal

Accumulated book depreciation for all public and private utility assets (ERABDE). Accumulated book depreciation is given as follows:

(5.1-9)

$$ERABDE = ERABDL_{(y-1)} + ERBDE - ERBTIR$$

where

ERABDE = accumulated book depreciation, all assets

$ERABDL_{(y-1)}$ = accumulated book depreciation expense for last year

ERBDE = book depreciation for all assets

ERBTIR = book value of all retirements

The book depreciation is a function of the book value and takes into account the plant type for each build, the year in which the plant comes online, the percentage of the year the plant is in service during the first year, the book life for new assets by plant type, the book depreciation rate for old assets by plant type, the book life for old assets by plant type, the accumulated book depreciation expense for the previous year, the booked value of existing assets, the value of existing assets net of AFUDC, the share of public and private generation, and the number of vintage years.

Provision for deferred income taxes (ERPRDF). The provision for deferred income taxes is the sum of the values of all deferred income taxes or deferred tax savings (excluding investment tax credits). For purposes of the EFP, this sum includes the deferred taxes from accelerated depreciation and the deferred tax savings from the debt portion of AFUDC on assets not affected by the TRA of 1986. The provision for deferred income taxes is given as follows:

(5.1-10)

$$ERPRDF = DAD + DAFDC - EREDTF$$

where

ERPRDF = provision for deferred income taxes

DAD = deferred income taxes as a result of accelerated depreciation

DAFDC = deferred tax savings from the debt portion of AFUDC

EREDTF = excess deferred taxes flowed back to ratepayers

Book value of canceled projects not in rate base (ERCNBV) and accumulated depreciation of canceled projects not in rate base (ERCNAD). After the Three Mile Island nuclear plant incident,[59] many

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[59] The Three Mile Island Unit 2 (TMI-2) reactor, near Middletown, Pennsylvania, partially melted down on March 28, 1979. The accident brought about many changes to nuclear power plant operations and caused the Nuclear Regulatory Commission to tighten and heighten its regulatory oversight. For more information, see *Backgrounder on the Three Mile Island Accident*, U.S. Nuclear Regulatory Commission.

regulations were put into place requiring added safety features in nuclear plants that greatly increased the cost of building such plants. Nuclear plants that were under construction at the time of the incident became subject to these new regulations. In some cases, the projected added costs to complete the plant build with the added safety enhancements rendered the project too expensive; thus it was canceled. The values of ERCNBV and ERCNAD—the book value and accumulated depreciation of canceled projects whose unamortized balance is not allowed in the rate base—were calculated by summing the costs of all canceled projects. They contributed to electricity prices in historical years but have been paid off and thus do not contribute to current electricity prices. Thus the values for ERCNBV and ERCNAD are now zero. The book values and accumulated depreciation of canceled projects not in rate base are given as follows:

(5.1-11)
$$ERCNBV = \sum ERBVYE_{eican}$$

where

ERCNBV	=	Book value of canceled projects not in rate base
ERBVYE$_{eican}$	=	Book value of new canceled plant assets at the end of the year

(5.1-12)
$$ERCNAD = \sum (EBABDE + BDE)$$

For all canceled plant types,

where

ERCNAD	=	Accumulated depreciation of canceled projects not in rate base
EBABDE	=	Accumulated book depreciation all assets by build
BDE	=	Book depreciation computations

More information on depreciation is available in Appendix 5.C.

Net deferred gain from sale/leaseback transactions (ESLNDG). The sale and leaseback of an electric plant by a utility allows the utility to circumvent constraints imposed by regulatory authorities, competition, bond indemnifications, or its tax position. It was an attractive means for reducing cost increases to ratepayers of plant builds with high capital costs (such as nuclear plants), allowing costs to be stretched out over the lease period of 25 years or 30 years. The net deferred gain from the sale of the plant is subtracted from the rate base.

(5.1-13)
$$ESLNDG = \sum (SLGAIN - AMOR \cdot YRSL)$$

For all sale/leaseback transactions,

where

ESLNDG	=	Total regional net deferred gain
SLGAIN	=	net of tax gain over book value from sale for each transaction
AMOR	=	amortized amount of tax gain for each transaction
YRSL	=	number of years between current year and start of sale/leaseback period

Detailed discussion of Sale/Leaseback Transactions is in Appendix 5.E.

Net disallowed plant (EDISNT). Disallowed plant refers to plant builds with capital costs that were higher than considered prudent by regulators. These disallowed plant costs generally refer to nuclear plant cost overruns. This subject, as well as the derivation of the following calculation of EDISNT, is discussed further in Appendix 5.F. The net disallowed plant is given as follows:

(5.1-14)
$$EDISNT = \sum \left(PIBKVL \cdot \left(1 - \left(YRPI/PIBKLF \right) \right) \right) \cdot DISPER$$

For all disallowed plants,

where

EDISNT	=	net disallowed plant
PIBKVL	=	book value of phase-in plant (input)
YRPI	=	index of first year of phase-in relative to current year
PIBKLF	=	book life of phase-in plant (input).
DISPER	=	fraction of phase-in plant disallowed (input)

Rate of return (ESRR). The rate of return is calculated as a weighted average of the cost of long-term debt, short-term debt, common equity, and preferred stock. The equation is given as follows:

(5.1-15) $$ESRR = ESPRLT \cdot ESEMDT + ESPRST \cdot ESRTST + ESPRCE \cdot ESRTCE + ESPRPS \cdot ESEMPS$$

where

ESRR	=	rate of return
ESPRLT	=	fraction of capital structure made up by long-term debt
ESEMDT	=	embedded cost of long-term debt (explanation below)
ESPRST	=	fraction of capital structure made up by short-term debt

ESRTST   =   cost of short-term debt

ESPRCE   =   fraction of capital structure made up by common equity

ESRTCE   =   cost of common equity (explanation below)

ESPRPS   =   fraction of capital structure made up by preferred stock

ESEMPS   =   embedded cost of preferred stock (explanation below)

With the exception of ESEMDT, ESRTCE, and ESEMPS, all of the above values are inputs into EFP.

Embedded cost of long-term debt (ESEMDT). The embedded cost of long-term debt in any year is a function of several quantities including the cost of new debt, the cost of existing debt, and the timing and quantity of retirements and issues of new debt, and is given as follows:

(5.1-16)
$$ESEMDT = \frac{(ESEMDL \cdot ERBNDL - ESEMDB \cdot RETIRE + ESRTLT \cdot (ERBOND - ERBNDL + RETIRE))}{ERBOND}$$

where

ESEMDT   =   embedded cost of long-term debt

ESEMDL   =   embedded cost of long-term debt in previous year

ERBNDL   =   total long-term debt outstanding from previous year

ESEMDB   =   embedded cost of long-term debt in the year previous to the first projection year

RETIRE   =   amount of debt that is retired in current year, as determined by calculating the maximum of: ESPRLT * ERBDE; and EROBL, where ESPRLT = fraction of capital structure made up by long-term debt, ERBDE = book depreciation expense, and EROBL = long-term debt outstanding in previous year that was issued before the first year of the projection period

ESRTLT   =   cost of new long term debt as determined by the national yield on new AA corporate bonds

ERBOND   =   total long-term debt outstanding in current year, as determined by ERAMD * ESPRLT, where ERAMD = assets minus deferral (the amount that must be financed), and ESPRLT = fraction of capital structure made up by long-term debt

The algorithm calculates the embedded cost of debt as a weighted average of the embedded cost in the previous year (ESEMDL); the embedded cost in the base year (ESEMDB); and the cost of new long-term debt issued in the current year (ESRTNB). Only debt issued before the projection period is assumed to be retired. This assumption is appropriate, given the mid-range projection period over which EFP projects.

To better represent the risks facing developers of new generating plants in the restructured environment, the cost of capital has been re-evaluated. The yield on debt represents that of an AA

corporate bond rather than that of utilities. For a more detailed discussion of the cost of capital used for capacity planning decisions please see Appendix 3. C.

Cost of common equity (ESRTCE). The cost-of-equity algorithm is based on the Capital Asset Pricing Model (CAPM). CAPM states that, given specific assumptions,[60] the cost of equity for a particular corporation is equal to a risk-free rate of return plus a premium equal to the difference between the market rate of return and that risk-free rate times a beta coefficient. Beta is a measure of an asset's sensitivity to market movements.[61] A beta equal to 1.5 for a particular company means that the return on the company's stock is 1.5 times as volatile as the return on the stock market in general. More volatility means that a company's stock is more risky. More risk commands a higher rate of return for investors. A higher required rate of return for investors means that the corporation has a higher cost of equity.

The mathematical specification of the CAPM is as follows:

(5.1-17)
$$R_E = R_F + \beta \left(R_M - R_F \right)$$

where

R_E	=	the required return on the company's common stock
R_F	=	the risk-free rate of return (generally the return on 90-day Treasury bills)
β	=	the beta coefficient
R_M	=	the return on the market.

For the purposes of EFP, the risk-free rate of return is the real Treasury bill (T-bill) rate from the NEMS MAM plus an exogenous inflation rate.[62] The return on the market is also an exogenous input.[63] Since all other parameters are fixed or determine external to the EFP, the beta coefficient provides the dynamic properties of the cost of equity to electric utilities in the EFP. Through the beta coefficient, the EFP translates the projections of operational and financial conditions into the cost of equity for utilities. The cost of equity affects the pricing of electricity in the EFP, as well as capacity planning decisions in the ECP. The value of β was determined exogenously based on historical values of unregulated industries with characteristics similar to the restructured electricity generation sector.

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[60] For a detailed description of CAPM, see U.S. Energy Information Administration, *Investor Perceptions of Nuclear Power*, DOE/EIA-0446 (Washington, DC, May 1984).

[61] Beta is the covariance of rates of returns between the company and the market. The market rate of return is measured by some index, such as the S&P 500.

[62] The inflation rate used may be exogenous or may be the inflation rate from the MAM. The decision as to which inflation rate to use will depend on the range of inflation rates across NEMS cases. An inflation rate that is unrealistically high or low given other economic conditions may generate perverse results in the ECP submodule.

[63] It is beyond the scope of NEMS to forecast a return on the stock market.

Embedded cost of preferred stock (ESEMPS). The embedded cost of preferred stock is calculated in an algorithm similar to that used for the embedded cost of long-term debt above, which is given by the following:

(5.1-18)
$$ESEMPS = \frac{(ESEMPL \cdot ERPRFL - ESEMPB \cdot RETIRE + ESRTPS \cdot (ERPREF - ERPRFL + RETIRE))}{ERPREF}$$

where

ESEMPS	=	embedded cost of preferred stock
ERPRFL	=	total preferred stock from previous year
ESEMPB	=	embedded cost of preferred stock from the year previous to the first projection year
RETIRE	=	amount of preferred stock that is retired in current year—maximum of: ESPRPS * ERBDE; and ERPFL (ESPRPS = fraction of capital structure made up by preferred stock, ERBDE = book depreciation expense, and ERPFL = preferred stock outstanding in previous year that was issued before the first year of the projection period)
ESRTPS	=	PSRCF1 + (PSRCF2 * ESRTDA) where PSRCF1 and PSRCF2 are regression coefficients for preferred stock and ESRTDA is the average of all regional new long-term utility debt
ERPREF	=	total preferred stock in current year—ERAMD * ESPRPS (ERAMD = assets minus deferrals and ESPRPS = fraction of capital structure made up by preferred stock)
ERBDE	=	book depreciation expense preferred stock outstanding in previous year that was issued before the first year of the projection period

The values of ESEMPB and ERPFL (for the first projection year) are input into EFP. These values can be derived from historical financial statements such as the FERC Form 1.

Fuel costs (ERTFLN). Fuel costs in each projection year are derived from the results of the dispatch exercise. EFP adjusts these fuel costs to include any costs of purchasing allowances for emission credit programs or renewable portfolio standards, which are also passed from the dispatch model.

Although distribution costs would not typically include fuel costs, within EMM this component is used to include the impact of allowance rebates provided when allowances are allocated to load serving entities (and will reflect a negative cost) and for passing through the incremental energy efficiency program costs related to AB398 and state nuclear zero-emission credit programs, as discussed in Chapter 3. The fuel cost is given by the following:

(5.1-19)
$$ERTFLN = (EFPFL + BLKSUM) \cdot ESGNPD$$

where

ERTFLN = nominal dollar fuel cost

EFPFL = real dollar fuel costs as determined by the dispatch model

BLKSUM = real dollar wholesale electricity purchase costs (includes imports, exports, purchases from nonutility generators and interregional transfers), as determined by the dispatch model

ESGNPD = inflation index to convert real dollars to nominal dollars

Operation and maintenance (O&M), excluding fuel (ERTOMN). As with fuel costs, O&M costs are input to EFP from other modules that are being used to drive EFP. Again, if necessary, these costs are inflated each year by a user-defined inflation rate. O&M costs are calculated differently for generation, transmission, and distribution.

Generation O&M costs are given by the following:

(5.1-20)

$$ERTOMN_{ISECT=1} = (ERTOM + OVERPR + ERTOMF + OMLE) \cdot ESGNPD$$

where

ERTOMN$_{ISECT=1}$ = O&M costs of the generation sector, excluding fuel cost, in nominal dollars (ISECT = 1 specifies the generation sector)

ERTOM = real dollar production related variable operation and maintenance expenses

OVERPR = real dollar production and maintenance expenses allocated to the production function (for example, general and administrative)

ERTOMF = real dollar production related fixed O&M expenses

OMLE = real dollar O&M expenses associated with the life extension of the generating units

ESGNPD = inflation index to convert real dollars to nominal dollars

Transmission O&M costs are given by the following:

(5.1-21)

$$ERTOMN_{ISECT=2} = (ERTOMT + OVERTR) \cdot ESGNPD$$

where

ERTOMN$_{ISECT=2}$ = O&M costs of the transmission sector, excluding fuel cost, in nominal dollars (ISECT = 2 specifies the transmission sector)

ERTOMT = real dollar transmission operation and maintenance expenses

OVERTR	=	real dollar overhead-related O&M expenses allocated to transmission (for example, general administration)
ESGNPD	=	inflation index to convert real dollars to nominal dollars

O&M costs are input to EFP from the distribution model that is being used to drive EFP. If necessary, these costs are inflated each year by a user-defined inflation rate. Distribution O&M costs are given by the following:

(5.1-22)

$$ERTOMN_{ISECT=3} = (ERTOMD + OVERDS) \cdot ESGNPD$$

where

$ERTOMN_{ISECT=3}$	=	O&M costs of the distribution sector, excluding fuel cost, in nominal dollars (ISECT = 3 specifies the distribution sector)
ERTOMD	=	real dollar operation and maintenance expenses associated with distribution
ESGNPD	=	inflation index to convert real dollars to nominal dollars
OVERDS	=	real dollar overhead related O&M expenses allowed to distribution (for example, general administration).

Depreciation for financial purposes (ERBDE). Book depreciation is calculated using the straight-line method (net book value divided by remaining life):

(5.1-23)

$$ERBDE_y = (EBBKVL - EBABDE_{y-1}) / (ESBKLF - (YEAR - EBSYR))$$

and

(5.1-24)

$$EBABDE_y = \sum_{i=EBSYR}^{y} ERBDE_i$$

for y = EBSYR to EBSYR + ESBKLF − 1 (that is, over service life of assets)

where

$ERBDE_y$	=	book depreciation, year y
EBBKVL	=	book value of plant (includes any AFUDC).
$EBABDE_{y-1}$	=	accumulated book depreciation, previous year to year y
ESBKLF	=	book life of plant
YEAR	=	current year
EBSYR	=	year plant comes online

EBABDE$_y$	=	accumulated book depreciation, year y

The derivation of EBBKVL is discussed in Appendix 5.B. (see equation App5.B-8). When the plant retires (year EBSYR + ESBKLF), its book value is added to account ERBTIR and subtracted from EBABDE. This process has the effect of removing the plant from the books. Further discussion of depreciation is provided below in Appendix 5.C.

General taxes for regulatory purposes (GENREG). General taxes encompass all taxes except state and federal income taxes. Among these taxes are gross receipts, FICA, payroll, property, and sales. These taxes each year are assumed to be a constant percentage of revenue requirements. The general taxes for regulatory purposes are given by the following:

(5.1-25)

$$GENREG = EGTXRT \cdot ERRVRQ + ERPRTX + ERSLTX$$

where

GENREG	=	general taxes for regulatory purposes
EGTXRT	=	gross receipts tax rate
ERRVRQ	=	revenue requirement
ERPRTX	=	property taxes
ERSLTX	=	sales tax

The gross receipts tax rate is an input that is calculated from base-year data (for example, FERC Form 1, Form EIA-412). Including ERRVRQ on the right-hand side of the equation appears to make this calculation circular (in other words, ERRVRQ is a function of GENREG and GENREG is a function of ERRVRQ). However, the equations for ERRVRQ and GENREG (along with STAREG and FEDREG, discussed next) are part of a system of four linear equations with four unknowns. Using the method known as algebraic substitution, one can solve for the value of ERRVRQ. Discussion of this method takes place below in the Resolution of ERRVRQ Circular Argument section. ERPRTX is modeled as an input fraction of book value, and ERSLTX is modeled as an input fraction of construction expenditures.

State income taxes for regulatory purposes (STAREG). STAREG is equal to state taxable income for regulatory purposes multiplied by the state income tax rate, as shown in the following:

(5.1-26)

$$STAREG = (ERRVRQ - ERTFLN - ERTOMN - ERTDWO - ERTIEX - ESLLP) \cdot ESSTXR$$

where

STAREG	=	state income taxes for regulatory purposes
ERRVRQ	=	revenue requirement

ERTFLN	=	fuel expense
ERTOMN	=	operation and maintenance expense, excluding fuel costs
ERTDWO	=	depreciation for tax purposes, without acceleration
ERTIEX	=	interest expense
ESLLP	=	lease payment associated with sale/leaseback transactions
ESSTXR	=	state income tax rate

Interest expenses (ERTIEX). The total interest expense depends on the cost of debt and on the average amount of debt outstanding during the year, given by the following:

(5.1-27)
$$ERTIEX = ERSIEX + ERLIEX$$

(5.1-28)
$$ERSIEX = ESRTST \cdot ESPRST \cdot \frac{(ERAMD + ERAMDL - ESLPRC)}{2}$$

(5.1-29)
$$ERLIEX = ESEMDT \cdot ESPRLT \cdot \frac{(ERAMD + ERAMDL - ESLPRC)}{2}$$

where

ERTIEX	=	total interest expense
ERSIEX	=	short-term interest expense
ERLIEX	=	long-term interest expense
ESRTST	=	cost of short-term debt
ESPRST	=	fraction of capital structure made up by short-term debt
ERAMD	=	assets minus deferrals (equals amount that must be financed through debt or equity)
ERAMDL	=	assets minus deferrals from previous year
ESLPRC	=	net of tax sales proceeds from sale/leaseback transactions
ESEMDT	=	embedded cost of long-term debt
ESPRLT	=	fraction of capital structure made up by long-term debt

ESRTST, ESPRST, and ESPRLT are user inputs. ESEMDT is defined above (See *Embedded Cost of Long-Term Debt* and Equation 5.1-16). ERAMDL for a given year is equal to ERAMD from the previous year. ERAMD is discussed in the next section, and ESLPRC is discussed in Appendix 5.E.

Assets minus deferrals (ERAMD). ERAMD is the amount that must be financed by debt or equity, given by the following:

(5.1-30)

$$ERAMD = ERTUP + ERBCWP + ERWC + ERNFSN + EPIDEF$$
$$- ERABDE - ERPRDF - ERDITC - EDISNT - ESLNDG$$

where

ERTUP	=	total utility plant assets (see Equation 5.1-5)
ERBCWP	=	booked construction work in progress (see Appendix 5.B. for further discussion)
ERWC	=	working capital (see Equation 5.1-7)
ERNFSN	=	nuclear fuel stock (see Equation 5.1-8)
EPIDEF	=	cumulative deferred phase-in revenues (see Appendix 5.F.)
ERABDE	=	accumulated book depreciation (see Appendix 5.D.)
ERPRDF	=	provision for deferred income taxes (see Appendix 5.C.)
ERDITC	=	deferred investment tax credits (see Appendix 5.C.)
EDISNT	=	net disallowed plant (see Appendix 5.F.)
ESLNDG	=	net deferred gain from sale/leaseback transactions (see Appendix 5.E.)

Federal income taxes for regulatory purposes (FEDREG). FEDREG is equal to federal taxable income (for regulatory purposes) multiplied by the federal income tax rate, adjusted by several accounts reflecting timing differences between actual income taxes paid and regulatory income taxes. FEDREG is given by the following:

(5.1-31)

$$FEDREG = (ERRVRQ - ERTFLN - ERTOMN - GENREG - STAREG - ERTDRG - ERTIEX + ERCIDC$$
$$- ESLLP) \cdot ESFTXR - ERFITC - ERAITC - ERFFDC - ERAFDC - EREDTF$$

where

FEDREG	=	federal income taxes for regulatory purposes
ERRVRQ	=	revenue requirement
ERTFLN	=	fuel expense
ERTOMN	=	operation and maintenance expense, excluding fuel costs

GENREG	=	general taxes for regulatory purposes
STAREG	=	State income taxes for regulatory purposes
ERTDRG	=	tax depreciation expense for regulatory purposes
ERTIEX	=	interest expenses
ERCIDC	=	interest expenses capitalized for purposes of calculating federal income taxes for regulatory purposes
ESLLP	=	lease payment associated with sale/leaseback transactions
ESFTXR	=	federal income tax rate
ERFITC	=	generated investment tax credits (ITC) that are flowed through
ERAITC	=	amortization of deferred ITC
ERFFDC	=	generated tax savings from the debt portion of AFUDC that is flowed through
ERAFDC	=	amortization of deferred tax savings from the debt portion of AFUDC
EREDTF	=	excess deferred taxes flowed back to ratepayers

ERRVRQ on the right side of the equation is discussed below in the Resolution of ERRVRQ Circular Argument section. ESFTXR is a user-supplied input. FEDREG includes the effects of the ITC or the tax savings as a result of the debt portion of AFUDC. These effects are captured with the variables ERFITC, ERAITC, ERFEDC, and ERAFDC.

Allowance for funds used during construction (AFUDC) offset (EROFFS). When CWIP is allowed in rate base, the utility is allowed to earn a current cash return on all construction outlays. If CWIP is not allowed in rate base (in other words, AFUDC is capitalized) the utility is allowed to include an annual estimate of the net cost, for the period of construction, of funds used for construction purposes. These allowances are accumulated over the construction period of the project and are brought into the rate base as an addition to the value of the completed investment once the investment becomes operational. The third alternative of dealing with construction work in progress is the capitalized AFUDC offset method. For this procedure, CWIP is allowed in rate base and AFUDC is capitalized, but there is a corresponding offset to the return on rate base equal to the amount of the capitalized AFUDC.

The AFUDC offset is calculated as follows:

(5.1-32)
$$EROFFS_y = AFUDC_y \cdot ESRBAF$$

where

$EROFFS_y$	=	AFUDC offset, year y

AFUDC$_y$	=	AFUDC year y
ESRBAF	=	Percentage of AFUDC/CWIP that receives offset treatment

Appendix 5.B. discusses further.

Net lease payments associated with sale/leaseback transactions (ESLLPN). The sale and leaseback of an electric plant by a utility is a creative way for the utility to circumvent constraints imposed by regulatory authorities, competition, bond indemnifications, or its tax position, benefitting both investors and ratepayers. Regulators treat the rental payment as operating expenses, and the utility's revenue requirement no longer includes the return on capital or depreciation expense associated with the plant. The result is a flat revenue requirement over time, lower-than-conventional cost recovery in the short term, and higher toward the end of the lease. Net lease payment is given by the following:

(5.1-33)
$$ESLLPN = ESLLP - ESLAGN$$

where

ESLLPN	=	net lease payment
ESLLP	=	annual lease payment
ESLAGN	=	amortization of gain

Appendix 5.E. further discusses.

Net deferred phase-in costs (EPIND). Under traditional cost-of-service, rate-of-return regulation, the rate impacts of the capital costs of a new asset coming online are greatest in its first year of service and decline thereafter over the life of the asset. Historically, the large increase in capital costs associated with a new plant were substantially, if not totally, offset by the lower operating costs obtained by utilizing the new unit.

Sometimes, however, the costs of building a new power plant are not offset by lower operating costs. This possibility can occur because of one or more of the following factors: energy commodity prices are low, new power generation technologies are not much more efficient than previous technologies, a utility has overbuilt capacity, or the cost to finish a plant build is higher than expected, such as with many nuclear facilities. To decrease the impact of such new plant builds to the ratepayer, some of the early capital costs are deferred and are phased in more evenly over the life of the asset. The net deferred costs are given as follows:

(5.1-34)
$$EPIND = \sum DEFCST$$

Over all phase-in plants,

where

EPIND   =   net (pre-tax) deferred costs

DEFCST   =   deferred (after tax) cost of each plant

Appendix 5.F. provides a more detailed description of rate phase-in plans and derivation of EPIND and DEFCST.

Nuclear decommissioning. The data required for each nuclear plant consists of 11 fields. Each data record describes a nuclear unit or a plant containing more than one unit (only if unit parameters are similar and the utility owner did not specify data by unit). The database is input into NEMS in the phase-in input data file.

After the data are input, the EFP implements the nuclear decommissioning methodology, which consists of three steps:

1.   Calculate estimates of missing data

2.   Initialize all data to start year of NEMS (1990)

3.   Perform annual calculations

Each step is discussed below.

Calculate estimates of missing data:

The input database for each nuclear unit includes the balance of the fund as well as the most recent annual payment into the fund. For nuclear units for which this information is not available from the input database, the EFP estimates the values under the assumption that the payment patterns for these units are similar to the average pattern observed for all units for which data are available.

Initialize all data to start year of NEMS (1990):

The total estimated decommissioning costs, fund balances, and fund payments for each nuclear unit are derived from the most recent data available. The purpose of this step is to adjust these inputs to reflect values applicable to 1990 (beginning of the year). This adjustment accounts for the impact of escalation and inflation that occurs between the beginning of 1990 and the date for which input values actually apply.

Perform annual calculations:

For each projection year, the fund balance for each unit is calculated as follows:

$$\text{(5.1-35)} \quad Balance_y = Balance_{y-1} + Earnings_y - Tax_y - (Administrative\ Cost)_y + Payment_y$$

where the fund payment is calculated in one of two ways:

1)   For years before the early retirement year (if applicable) and before the input catch-up year, the payment is calculated as the input payment adjusted for inflation.

2)   For all other years, the payment is calculated as the annuity payment necessary over the remaining period of collection (in other words, through the year of retirement plus any input maintenance period) to result in a fund balance sufficient to pay the current estimated decommissioning costs. Note that this calculation does not take into account any future real escalation in decommissioning costs nor any early retirement of the unit. As this escalation occurs in each subsequent year, the payment will rise accordingly. Only when the year of retirement is reached does the fund payment rise to reflect the shorter collection period.

Within the model, each annual fund payment can be covered by one of three sources of funds within the model: (1) the ratepayers, (2) the equity holders, or (3) the government. The methodology assumes that the total fund payment will continue to be collected from the ratepayers until the earlier of a catch-up year or an early retirement year. The increase in payment that occurs in either of these years is shared between the three sources according to the input shares. Any monitoring costs are assumed to be recovered from the ratepayers as they are incurred.

Resolution of ERRVRQ circular argument. The following four equations have been presented:

(1) ERRVRQ   =   . . . + GENREG + STAREG + FEDREG + . . . (see Equation 5.1-1)

(2) GENREG   =   EGTXRT · ERRVRQ + . . . (see Equation 5.1-25)

(3) STAREG   =   (ERRVRQ - . . .) · ESSTXR (see Equation 5.1-26)

(4) FEDREG   =   (ERRVRQ - . . . . - STAREG - GENREG) · ESFTXR (see Equation 5.1-31)

In the presentation above, these equations seem to present a circular calculation. ERRVRQ, the revenue requirement, is a function of GENREG, STAREG, and FEDREG (general regulatory, state and federal taxes), while at the same time these taxes are determined by the revenue requirement. This specification is not really a problem because the above is just a system of four linear equations with four unknowns, which EFP solves by algebraic substitution.

5.2 Competitive Pricing Algorithm

This section documents the modifications necessary to allow the calculation of spot prices for generation. The prices do not indicate the locational variations that one would expect from true spot prices, which would result from localized network congestion and other phenomena.

It is well known that the optimal spot price is equal to the marginal cost of electricity. In this model, the costs of generation to be covered comprise: (1) the marginal operating costs, including marginal generator fuel costs, and variable operations and maintenance costs; (2) a capacity payment to represent capital recovery needed to support sufficient capacity and operating (spinning) reserves; and (3) taxes. Because transmission and distribution are assumed to remain regulated, the price subject to competition is the sum of the generation costs. No changes were made in the calculation of the average transmission and distribution costs. Capital recovery is not explicitly represented in the competitive price of electricity generation because capital and all other costs must be recovered from the difference between the market clearing price and the operating cost of each unit. The following is a description of three components of the competitive spot prices calculated in this model.

In summary, the spot price of electricity under competition is represented as follows:

(5.2-1) $\boldsymbol{Pcomp_{ryt} = E_{ryt} + C_{ry} + Tax_{ry} + TD_{ry}}$

where

Pcomp_{ryt}	=	the competitive price of delivered electricity in region r, year y, period t (cents per kilowatthour),
E_{ryt}	=	the marginal short-run operating cost in region r, year y, period t (variable operating costs of the last plant dispatched in period t, in cents per kilowatthour),
C_{ry}	=	the capacity payment in region r, year y (cents per kilowatthour),
Tax_{ry}	=	recovery of federal income taxes and all other taxes in region r, year y (cents per kilowatthour), and
TD_{ry}	=	average transmission and distribution costs in region r, year y (cents per kilowatthour).

The marginal production costs are based on estimates of the marginal costs of generation. Some costs, including fuel, other consumables, and some maintenance vary directly with the hour-by-hour level of output of a plant. The competitive price then includes the marginal short-run operating costs—that is, the operating cost of the last plant dispatched (assumed to be the most-expensive plant running) in each of the nine time periods passed through from the EFD submodule. This price is obtained from the reduced cost of the demand constraint in the EFD LP. By the nature of a linear program, the marginal energy cost will also include the costs that that marginal plant incurs to meet other constraints, such as emission caps, and therefore the marginal energy cost will include allowance costs. Some constraints, such as the must-run constraint and short-term benchmarking constraint, impose additional requirements on operation that shift costs from the demand constraint. Therefore, the reduced costs from these two constraints are also captured in the EFD and passed to the EFP, where they are added to marginal energy costs.

The model provides an option to lag these marginal operating costs, by storing the previous year's value and calculating a weighted average of the previous and current marginal costs (for example, a weight of 50% implies a half-year lag). This option may be desired when fuel prices, particularly natural gas prices, are fluctuating quickly. Even in a competitive environment, fuel price changes may not immediately be reflected in the spot market prices because companies may purchase their fuel at longer-term contract prices.

The total cost of capacity (RMPOOL_{ry}) is calculated in the ECP as a weighted average of the levelized cost of a turbine and the marginal value of capacity, based on the duals from the ECP reserve margin constraint and the reserve capacity required. The EFD also calculates any costs associated with meeting the spinning reserve requirement (SRPOOL_{ry}) and this is added to this total pool of dollars that needs to be recovered. The EFP allocates these costs to the sectors based on their contribution to peak demand

and then recovers the costs over the total sector sales to calculate the final capacity payment (C_{ry}), as shown in the following:

$$(5.2\text{-}2) \ \ C_{ry} = (RMPOOL_{ry} + SRPOOL_{ry}) * SECANNPEAAVPCP_{rj}/SALCLS_{rj}$$

where

RMPOOL$_{ry}$	=	dollars needed to build extra capacity to satisfy the reserve margin by region r and year y
SRPOOL$_{ry}$	=	cost of satisfying the operating reserve requirements by region r and year y
SECANNPEAAVPCP$_{rj}$	=	the average contribution by region r to the system peak of customer class j over a number of previous model years
SALCLS$_{rj}$	=	the total sales of electricity to customer class j by region r

All taxes other than federal income taxes (in other words, state income taxes, sales taxes, and property taxes) are aggregated and treated as a gross receipts tax (revenue tax).

The total price for each slice is summed in subroutine COMPPRC. Annual prices for each of the end-use service sector are calculated in subroutine RATES2. In the subroutine ELSET, these prices are modified to reflect the transition to full competition, sectoral adjustments are applied, and the prices are converted to the census division level. Subroutine REVGAP was added to summarize the relationship between revenues and total costs for each region.

5.3 Remaining Algorithms

Section 5.1 of this chapter described the EFP algorithms used to project the major components of revenue requirements to project regulated electricity prices based on average cost calculations, while Section 5.2 of this section described how competitive prices are computed. This section describes the remaining algorithms, which are used to yield projections of electricity revenues, allocation of costs to customer classes, regulated prices of electricity, taxes (both current and for financial purposes), financial ratios, and other projections.

Electricity revenues:

Electricity revenues are a function of revenue requirements and the regulatory lag. Regulatory lag can result from the situation where electric utility rates (and thus revenues) are based on costs from a historical test year rather than on costs from the period during which the rates are in effect. Usually a utility must wait for approval from the state regulatory body, following an official rate case, to change its revenue requirements allowance and, therefore, customer electricity prices. The EFP calculates electricity revenues under five different assumptions: no lag, one-year lag, one-quarter-year lag, one-half-year lag, and three-quarter-year lag.

In a no-lag scenario, rates are based on current year experience and rate base, so electricity revenues are equal to the revenue requirements calculated in part 1 above as shown in the following:

(5.3-1) $$ERRVLG = ERRVRQ$$

where

ERRVLG	=	electricity revenues
ERRVRQ	=	revenue requirements

In a one-year lag scenario, electric revenues are calculated as follows:

(5.3-2)

$$ERRVLG_y = [(ERRB'_{y-1} \cdot ESRR_y) + ERTOMN_{y-1} + ERBDE_{y-1} + GENREG_{y-1} + STAREG_{y-1}$$
$$+ FEDREG_{y-1} - EROFFS_{y-1} + ESLLPN_{y-1} - EPIND_{y-1}] \cdot EQTLSL_y / EQTLSL_{y-1} + ERTFLN_y$$

where the variables are defined as in part 1 above, except:

ERRB'$_{y-1}$	=	ERRB$_{y-1}$ + (EBRCWP$_y$ - EBRCWP$_{y-1}$)
EQTLSL$_y$	=	total sales of electricity, year y.

This equation is similar to the equation for revenue requirements presented in 5.3-1 above. However, the variables are lagged by one year, with some exceptions. First, the rate base differs from the previous year's rate base by the difference in the amount of CWIP allowed in rate base. This difference in the rate base reflects the fact that the amount of CWIP in rate base is determined by order in each rate case and does not reflect a historically observed value. Similarly, the rate of return on rate base is not the previous year's value but instead reflects the regulatory commission's current finding on the appropriate return. Next, a factor equal to the ratio of current-year sales to previous-year sales is applied because the rates are based on historical expenses and sales but will be collected on the current-year sales. Finally, fuel costs are not lagged, but instead they recovered as they are incurred. The result is that the price of electricity is the sum of the fuel cost (recovered through an instantaneously adjusting fuel adjustment clause) and base rates set in rate hearings.

Weighted averages of the revenues under the no-lag and one-year lag cases are used in the other scenarios (for example, one-half-year lag).

Projected sales of electricity are passed to the EFP from the dispatch submodule (EFD).

Allocation of costs to customer classes. Costs are functionalized by stage of production and classified as capital-related, fixed O&M, variable O&M, or fuel for each modeled region. Each of these categories may be allocated to the various customer classes using a variety of methods, depending on the type of costs and how most utilities are expected to assign them. For instance the fuel, fixed O&M, and capital portions of generation costs may be allocated by the non-coincident peak method and the variable O&M portion of the generation costs allocated by the sales method while 70% of fixed O&M and capital distribution costs are allocated by the non-coincidental peak method and 30% by the customer method.

For all methods of allocation:

DEMFAC$_{nj}$ = the allocation proportion using method n for customer class j.

All demand factors are calculated at the regional level, but for simplification the regional index is not included in the equations below.

Sales method. Costs are allocated on the basis of the proportion of total sales to the class as follows:

(5.3-3a)
$$DEMFAC_{1j} = SALCLS_j \ / \ SALTOT$$

where

SALCLS$_j$ = the total sales of electricity to customer class j

SALTOT = the total sales of electricity to all classes

Customer method. Costs are allocated based on the proportion of customers in each customer class, given as follows:

(5.3-3b)
$$DEMFAC_{4j} = CUST_j \ / \ TOTAL$$

where

CUST$_j$ = the total number of customers in customer class j

TOTAL = the total number of customers

Coincident peak method. Costs are allocated on the basis of each customer class's contribution to the system peak load as follows:

(5.3-3c)
$$DEMFAC_{5j} = SECANNUALPEAK_{1j} \ / \ TOTAL$$

where

SECANNUALPEAK$_{1j}$ = the load attributable to customer class j at the time of the total system peak load (coincident peak)

TOTAL = the total load on the system at the time of system peak

Probability of contribution to peak. Costs are allocated on the basis of the average contribution to system peak of the customer class over a number of previous model years, as follows:

(5.3-3d) $$DEMFAC_{6j} = SECANNPEAAVPCP_j/TOTAL$$

where

| SECANNPEAAVPCP$_j$ | = | the average contribution by region r to the system peak of customer class j over a number of previous model years |
| TOTAL | = | the sum of the average contributions to the system peaks of all customer classes over a number of previous model years |

Non-coincident peak method. In this method, costs are allocated on the basis of the proportion of the load of each customer class at the time of the customer class peak, divided by the sum of the customer class peaks, as follows:

(5.3-3e) $$DEMFAC_{7j} = SECANNUALPEAK_{2j}/TOTAL$$

where

| SECANNUALPEAK$_{2j}$ | = | the load at the time of the customer peak load, of customer class j |
| TOTAL | = | the sum of the customer class loads at the time of the peak for each individual customer class (non-coincident peak) |

Average and excess demand using coincident peak. Costs are allocated using a combination of the sales method (average demand) and the coincident peak (excess demand). The proportion of costs equal to the level of the system load factor is allocated on the basis of the sales method. The remaining costs are allocated on the basis of the coincident peak method, as follows:

(5.3-3f) $DEMFAC_{8j} = (SYSTEMLF \times DEMFAC_1) + [(1 - SYSTEMLF) \times DEMFAC_5]$

where

SYSTEMLF = the system load factor

Average and excess demand using probability of contribution to peak. This method is the same as that described above except that the proportion of costs in excess of the system load factor is allocated on the basis of the average contribution to peak instead of the coincident peak method, as follows:

(5.3-3g) $DEMFAC_{9j} = (SYSTEMLF \times DEMFAC_1) + [(1 - SYSTEMLF) \times DEMFAC_6]$

Allocation of costs to customer classes. Finally, all of the methods used for allocating each cost category (each cost type—capital, fuel, etc.—by stage of production) are summed for each of those cost categories, as follows:

(5.3-4) $$COSTFC_{kjl} = \sum_{n=1}^{n=9} DEMFAC_{nj} \cdot TECFAC_{knl}$$

where

COSTFC$_{kjl}$	=	the sum of all allocation proportions for cost type k, customer class j, and stage of production l
DEMFAC$_{nj}$	=	allocation proportion using method n for customer class j
TECFAC$_{knl}$	=	the proportion of cost type k to be allocated using method n for stage of production 1

and revenues are allocated to the class as follows:

(5.3-5) $$REV_{jl} = COSTFC_{kjl} \times COST_{kl}$$

where

REV$_{j1}$	=	the revenues allocated to customer class j for stage of production l
COST$_{kl}$	=	the cost type k (classified cost) for stage of production l (functionalized cost)

Price of Electricity. With electricity revenues projected and allocated, the projected price of electricity is straightforward, as follows:

(5.3-6) $$EPRICE_{rjl} = REV_{jl}/SALCLS_{rj}$$

where

EPRICE$_{rjl}$	=	the price of electricity by region r for customer class j and stage of production l
REV$_{jl}$	=	electric revenues allocated to customer class j for stage of production l
SALCLS$_{rj}$	=	sales to customer class j by region r

Benchmark/subsidization calculation

Once the price of electricity has been calculated for each customer class and region at the distribution stage of production, the computed prices for the residential, commercial, and industrial sectors are compared with historical prices for benchmarking and subsidy calculation.[64] The prices for transportation are not benchmarked because (1) there is no relevant historical price for off-peak electric vehicles and (2) the proportion of costs allocated to this class is very small. Differences in the modeled prices and historical prices may result from differences between the modeled allocation techniques and those being used in practice, and they may be a result of customer class cross-subsidization where one customer class's cost allocation is increased or decreased for the purpose of accommodating another class. This benchmarking/subsidization routine is as follows:

First, the historical and projected proportions of revenues from each of the three classes are determined. Historical proportions are calculated as follows for the latest historical year:

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[64] This benchmarking/subsidization technique is not used for the generation or transmission transfer price calculations.

(5.3-7) $REVHPCT_{rj} = REVH_{rj} / REVHRCI_r$

where

REVHPCT$_{rj}$ =   the actual proportion of revenues in region r allocated to customer class j

REVH$_{rj}$ =   the actual revenues, by region r, allocated to customer class j

REVHRCI$_r$ =   the actual total revenues allocated to all three classes in region r

The modeled proportions used in future years are given as follows:

(5.3-8) $REVPCT_{rj} = REV_{rj} / REVRCI_r$

where

REVPCT$_{rj}$ =   the modeled proportion of revenues in region r allocated to customer class j

REV$_{rj}$ =   the modeled revenues allocated in region r to customer class j

REVRCI$_r$ =   the modeled total revenues allocated to all three classes in region r

The historical proportion of sales attributable to each customer class is calculated for the latest historical year as follows:

(5.3-9) $SLSHPCT_{rj} = SALH_{rj} / SLSHRCI_r$

where

SLSHPCT$_{rj}$ =   the actual proportion of sales in region r to customer class j

SALH$_{rj}$ =   the actual sales in region r to customer class j

SLSHRCI$_r$ =   the actual sales in region r to all three classes

The modeled proportion of sales for all the future years is given as follows:

(5.3-10) $SLSPCT_{rj} = SALCLS_{rj} / SLSRCI_r$

where

SLSPCT$_{rj}$ =   the modeled proportion of sales in region r to customer class j

SALCLS$_{rj}$ =   the modeled sales in region r to customer class j

SLSRCI$_r$ =   the modeled sales in region r to all three classes

The following ratios are then used to calculate the implied subsidy to be used to benchmark/subsidize customer class prices while controlling for differences in the level of actual sales to each customer class and modeled sales to each customer class:

(5.3-11) $SUBPCT_{rj} = (REVHPCT_{rj} - SLSHPCT_{rj}) - (REVPCT_{rj} - SLSPCT_{rj})$

where

$SUBPCT_{rj}$	=	the implied percentage of subsidy for customer class j in region r
$REVHPCT_{rj}$	=	the actual proportion of revenues allocated to customer class j in region r
$SLSHPCT_{rj}$	=	the actual proportion of sales to customer class j in region r
$REVPCT_{rj}$	=	the modeled proportion of revenues allocated to customer class j in region r
$SLSPCT_{rj}$	=	the modeled proportion of sales to customer class j in region r

Calculation of prices with benchmarking and subsidization. After the benchmarking/subsidization proportion has been calculated, it is multiplied by the total revenues allocated to the three benchmarked/subsidized customer classes to determine the revised allocation to each class. This revised allocation is again divided by sales to the class to determine the revised price, as follows:

(5.3-12) $EPRICE_{rj} = (REV_j + (REVRCI_r \cdot SUBPCT_{rj}))/(SALCLS_{rj})$

where

$EPRICE_{rj}$	=	the benchmarked/subsidized price of electricity by region r to customer class j
REV_j	=	the costs (revenues) allocated to customer class j before the benchmarking/subsidization routine
$REVRCI_r$	=	total costs allocated to the three customer classes
$SUBPCT_{rj}$	=	benchmarking/subsidy percentage by region r, for customer class j
$SALCLS_{rj}$	=	electricity sales by region r, to customer class j

Electricity pricing under competition. Electricity prices within a region are calculated in the model using both regulated and competitive algorithms. The final price for a region can reflect the fully regulated price, the fully competitive price, or a mix of the two, depending on each region's current status in deregulating their market. The price for mixed regions is a load-weighted average of the competitive

price and regulated price, and the weight is based on the percentage of electricity load in the region that has taken action to deregulate and is given as follows:

(5.3-13)

$$EPRICE_{jry} = (regEPRICE_{jry} \cdot (1 - compSLSHPCT_{ry})$$
$$+ (compEPRICE_{jry} \cdot compSLSHPCT_{ry})$$

where

$EPRICE_{jry}$	=	the nominal electricity price of customer class j in region r in year y
$regEPRICE_{jry}$	=	the nominal regulated electricity price of customer class j in region r in year y
$compEPRICE_{jry}$	=	the nominal competitive electricity price of customer class j in region r in year y
$compSLSHPCT_{jry}$	=	the competitive proportion of sales to customer class j in region r in year y

Taxes. EFP calculates two categories of taxes: general taxes and income taxes.

General Taxes. General taxes encompass all taxes except the state and federal income taxes. Among these taxes are gross receipts, FICA, capitalized payroll, property, and sales. The assumption is made that these taxes each year will be a constant percentage of revenues, and are given as follows:

(5.3-14)

$$GENTAX = EGTXRT \cdot ERRVLG + ERPRTX + ERSLTX$$

where

GENTAX	=	actual general taxes
EGTXRT	=	general tax rate (user input)
ERRVLG	=	electric revenues
ERPRTX	=	property taxes
ERSLTX	=	sales tax

ERPRTX is modeled as an input fraction of the book value of property, and ERSLTX is modeled as an input fraction of the construction expenditures.

Income Taxes. Current income taxes are those actually paid by the utility in a given year. Because of the regulatory and financial treatment of certain tax savings (for example, investment tax credits, accelerated depreciation), current taxes are not, in general, what is booked on the income statement as income tax expense. Income taxes are calculated as follows:

(5.3-15)

$$CITAX = (ERRVLG - ERTFLN - ERTOMN - ERTDWO - GENTAX - (ERTIEX - AVDINT) - ESLLP)$$
$$\cdot ESFTXR + STTAX - (ERFITC + XITCD) - (ERATSF + ERATSD)$$

where

CITAX	=	current income taxes
ERRVLG	=	electricity revenues
ERTFLN	=	fuel costs
ERTOMN	=	operation and maintenance expenses, excluding fuel
ERTDWO	=	depreciation for tax purposes, without acceleration
GENTAX	=	actual general taxes
ERTIEX	=	interest expenses
AVDINT	=	interest capitalized on assets during construction
ESLLP	=	annual lease payment associated with sale/leaseback transactions
ESFTXR	=	federal income tax rate (user input)
STTAX	=	state income taxes, including Federal income tax benefits (see Equation 5.3-37 below)
ERFITC	=	generated ITC that is flowed through
XITCD	=	generated ITC that is deferred
ERATSF	=	tax savings from accelerated depreciation that is flowed through
ERATSD	=	tax savings from accelerated depreciation that is deferred

Booked income tax expense is computed as current taxes, plus deferrals, minus amortizations, as follows:

(5.3-16)

$$BKITAX = CITAX + (XITCD - ERAITC) + (ERXFDC - ERAFDC) + ERATSD - EREDTF$$

where

BKITAX	=	booked income tax expense
ERAITC	=	amortization of deferred ITC
ERXFDC	=	generated tax savings from debt portion of AFUDC that is deferred
ERAFDC	=	amortization of deferred tax savings from the debt portion of AFUDC

EREDTF   =   excess deferred taxes flowed back to rate payers.

The only remaining tax variable to be explained is STTAX (state income taxes including federal income tax benefits), which is calculated as follows:

(5.3-17) $$STTAX = (ERRVLG - ERTFLN - ERTOMN - ERTDWO - ERTIEX -ESLLP) \cdot ESSTXR \cdot (1-ESFTXR)$$

where

  ESSTXR   =   state income tax rate (user input).

State income taxes are deductible in calculating federal taxable income so the net effect of state income taxes upon total income taxes is STTAX.

Financial ratios

The output of EFP includes the projected values of several financial ratios. These ratios are standard indicators of a utility company's financial health. However, financial analysts disagree over the exact formula to be used in some cases. For EFP, the following definitions are used:

- **Interest Coverage.** Interest coverage is calculated and printed for four alternative formulas. In all formulas, the denominator is total interest expenses. For pre-tax interest coverage, less AFUDC, the numerator is operating income plus booked income taxes. For pre-tax interest coverage, with AFUDC, the numerator is operating income, plus booked income taxes, plus AFUDC. For post-tax interest coverage, less AFUDC, the numerator is operating income. For post-tax interest coverage, with AFUDC, the numerator is operating income plus AFUDC.
- **Actual Return on Common Equity.** This ratio is calculated as earnings available for common equity divided by the year-average book value of common equity (common stock plus retained earnings).
- **AFUDC as a Percentage of Earnings Available for Common.** This ratio is calculated AFUDC divided by earnings available for common equity.
- **Internal Cash Flow as a Percentage of Construction Expenditures.** This ratio is calculated as total internally generated funds divided by construction expenditures (excluding AFUDC).
- **CWIP as a Percentage of Net Plant.** This ratio is calculated as total CWIP divided by net plant. Net plant includes both plant in service and CWIP.
- **Effective Tax Rate.** This rate is calculated as booked income taxes divided by booked pre-tax income. Pre-tax income is the sum of operating income and booked income taxes.
- **Safety Margin.** This ratio is calculated as net income plus booked income taxes, minus AFUDC, all divided by electric revenues.

Appendix 5.A. Data Sources

Utility expenses

Utility costs and tax data come from separate survey forms, depending on the type of utility. Data for investor-owned electric utilities come from Federal Energy Regulatory Commission (FERC) Form FERC 1, *Electric Utility Annual Report*. Data for government-owned-and-operated utilities such as federal and municipal power authorities (publicly owned) is no longer collected by EIA, and is compiled manually from individual company annual reports. Data for rural distribution cooperatives (publicly owned) come from the U.S. Department of Agriculture, Rural Utilities Service (RUS), Form RUS-7, *Financial and Operating Report Electric Distribution* and for all electric power supply and distribution cooperatives with generating facilities on Form RUS-12, *Financial and Operating Report Electric Power Supply*.

Form EIA-861, Annual Electric Power Industry Report

Form EIA-861 collects information on the status of electric power industry participants involved in the generation, transmission, and distribution of electric energy in the United States, its territories, and Puerto Rico. Form EIA-861 is completed by electric industry participants including electric utilities, wholesale power marketers (registered with the Federal Energy Regulatory Commission), energy service providers (registered with the states), and electric power producers. The EFP maps the EIA-861 sales data to EMM regions, and determines the competitive share for pricing based on assumed state programs and the shares of competitive sales reported on the EIA-861. The historical sales and revenues by sector are also used to develop benchmark factors for regulated sectoral pricing.

Appendix 5.B. Construction Work in Progress

For regulatory purposes, the Electricity Finance and Pricing (EFP) simulates three alternative treatments of construction work in progress (CWIP): 1) CWIP in rate base; 2) CWIP not in rate base; or 3) the offset method. When CWIP is allowed in rate base for ratemaking purposes, the utility is allowed to earn a current cash return on all construction outlays. If CWIP is not allowed in rate base (in other words, allowance for funds used during construction, or AFUDC, is capitalized), the utility is allowed to include an annual estimate of the net cost, for the period of construction, of funds used for construction purposes. These allowances are accumulated over the construction period of the project and are brought into the rate base as an addition to the value of the completed investment once the investment becomes operational. The third alternative of dealing with construction work in progress is the capitalized AFUDC offset method. For this procedure, CWIP is allowed in rate base and AFUDC is capitalized, but there is a corresponding offset to the return on rate base equal to the amount of the capitalized AFUDC. If the AFUDC rate is equal to the allowed rate of return on rate base and if the utility is allowed to compound the effects of AFUDC, then this method is essentially equivalent to not allowing CWIP in rate base.

The regulatory treatment of CWIP is decided on a case-by-case basis by most public utility commissions. In general, at the multi-utility aggregation level at which EFP is run, all of the treatments are used to some degree. To account for the varying treatment of CWIP, EFP allows the analyst to input the percentage of CWIP that is to be allowed in rate base, based on research indicating current regulatory treatment. The remainder of the CWIP is then assumed either not to be in rate base or to be handled under the offset method (depending on another user input).

The treatment of CWIP affects several variables. The following discussion assumes only one plant is being built for ease in presentation. For the algorithms, the following values are input to EFP:

Table 8. Variables used to calculate CWIP

Variable	Description	Source
EBPCAP	Capacity of build	Capacity Planning Model
EBPCST	Real-dollar cost per unit of capacity (real dollars/capacity), not including any financing costs incurred during construction	Capacity Planning Model
EBSYR	Year plant comes online	Capacity Planning Model
ESLCP	Length (in years) of construction period (including first year of operation)	User
$ESCPRF_y$	Direct (in other words, not including financing charges) construction expenditures (in real dollars) in year y as a fraction of total direct construction costs (in real dollars)	User
$ESGNPD_y$	Inflation escalation index used to convert real dollars to current year y dollars, expressed as the ratio of current year y dollars to real dollars	User
$CWPPER_y$	Percentage (expressed as a fraction) of CWIP allowed in rate base, year y	User
ESRBAF	Proportion of AFUDC/CWIP that receives offset treatment	User
	0 Remainder of CWIP (in other words, 1.0 - CWPPER) is not in rate base	
	1 Remainder of CWIP receives AFUDC offset treatment	
ESCGRW	Annual escalation rate used to escalate costs over and above the inflation rate	User
ESBKLF	Book life of plant	User

The algorithms to calculate the CWIP-related variables in EFP are executed in five basic steps:

    1) Calculate the AFUDC (allowance for funds used during construction) rate

    2) Calculate annual direct construction expenditures in current-year dollars

    3) Calculate year-by-year CWIP accounts and the resulting book value of the new plant

    4) Calculate tax basis of plant

    5) Calculate several AFUDC-related accounts

Each step is discussed in detail below.

Step 1 is to calculate the AFUDC rate. EFP simulates a pre-tax AFUDC rate. EFP calculates the pre-tax AFUDC rate as follows:

(App5.B-1) $$ESAFDC = TEMPD + TEMPE$$

where

ESAFDC	=	Pre-tax AFUDC rate
TEMPD	=	ESPRLT · ESEMDL + ESPRST ·ESRTST
TEMPE	=	ESPRCE · ESRTCE + ESPRPS · ESEMPL

All of the right-hand variables above have been discussed in the preceding sections. An additional value used is the fraction of AFUDC representing debt costs, given as follows:

(App5.B-2) $$ESWACD = TEMPD/ESAFDC$$

where

ESWACD	=	fraction of AFUDC representing debt costs.

Step 2 is to calculate direct construction expenditures by year, in nominal dollars. This process is done for each year y, where y ranges from the first year of construction (in other words, EBSYR - ESLCP + 1) to the first year of operation (in other words, EBSYR) and is given as follows:

(App5.B-3) $$EBYCWP_y = EBPCAP \cdot EBPCST \cdot ESCPRF_y \cdot ESGNPD_y \cdot CAPESC_y$$
$$\text{for } y = (EBSYR - ESLCP + 1) \text{ to } EBSYR$$

where

$EBYCWP_y$	=	nominal-dollar direct construction expenditures, year y
EBPCAP	=	capacity of build
EBPCST	=	real-dollar cost per unit of capacity
$ESCPRF_y$	=	real-dollar direct construction expenditures, in year y, as a fraction of total direct construction expenditures
$ESGNPD_y$	=	inflation index to convert real dollars to current year y dollars
$CAPESC_y$	=	escalation index to escalate construction costs over and above inflation
EBSYR	=	year plant comes online

ESLCP = length (in years) of construction period (including first year of operation).

EBPCAP, EBPCST, ESCPRF, ESGNPD, EBSYR, and ESLCP are inputs to EFP. CAPESC is calculated from the input values of ESCGRW (see description above of user inputs).

Step 3 includes calculation of the major CWIP-related accounts for each year y during the construction period. The following variables are computed for each year: CWIP allowed in rate base, booked CWIP, booked AFUDC, and the AFUDC offset. The book value of the new plant is also calculated.

CWIP allowed in rate base for year y is calculated as follows:

(App5.B-4) $EBRCWP_y = (EBBCWP_y + EBYCWP_y) \cdot [CWPPER_y + ESRBAF \cdot (1.0 - CWPPER_y)]$

where

$EBRCWP_y$	=	CWIP allowed in rate base by build, year y
$EBBCWP_{y-1}$	=	booked CWIP, year y-1
$EBYCWP_y$	=	nominal-dollar direct construction expenditures, year y
$CWPPER_y$	=	percentage of CWIP allowed in rate base, year y
$ESRBAF$	=	percentage of AFUDC/CWIP that receives offset treatment: 0 if no AFUDC offset, and 1 if AFUDC offset.

Booked AFUDC in year y is calculated as follows:

(App5.B-5) $AFUDC_y = (EBBCWP_{y-1} + 0.5\ EBYCWP_y) \cdot (1 - CWPPER_y) \cdot ESAFDC_y$

where

$AFUDC_y$	=	booked AFUDC, year y
$EBBCWP_{y-1}$	=	booked CWIP, year y-1
$EBYCWP_y$	=	nominal-dollar direct construction expenditures, year y
$CWPPER_y$	=	percentage of CWIP allowed in rate base, year y
$ESAFDC_y$	=	AFUDC rate, year y

Note that in the calculation of AFUDC the average level of CWIP over the calendar year is used, which is why $EBYCWP_j$ is multiplied by one-half (the construction takes place evenly over the year so the average balance should include only half of this amount). The calculation of CWIP in rate base, however, uses an end-of-year CWIP balance. Adjustments to this value to make it an average level over the year are made only if the user requests an average-year rate base.

ESAFDC and EBYCWP were calculated above in Steps 1 and 2, respectively. The calculation of EBBCWP is shown below.

Booked CWIP in year y is calculated as follows:

(App5.B-6)
$$EBBCWP_y = 0$$
$$\text{for } y = EBSYR - ESLCP \text{ (i.e., year before construction begins)}$$

$$= EBBCWP_{y-1} + EBYCWP_y + AFUDC_y$$
$$\text{for } y = (EBSYR - ESLCP + 1) \text{ to } EBSYR \text{ (i.e., construction period)}$$

where

$EBBCWP_y$	=	booked CWIP, year y
$EBYCWP_y$	=	nominal dollar direct construction expenditures, year y
$AFUDC_y$	=	booked AFUDC, year y

The AFUDC offset is calculated as follows:

(App5.B-7)
$$EROFFS_y = AFUDC_y \cdot ESRBAF$$

where

$EROFFS_y$	=	AFUDC offset, year y.

The book value of the new plant when it comes online is given as follows:

(App5.B-8)
$$EBBKVL = EBBCWP_y$$

where

EBBKVL	=	book value of new plant
Y	=	EBSYR (the first year of operation)
$EBBCWP_y$	=	booked CWIP, year y

This equation assumes that the new plant comes online January 1 of year EBBSYR. EFP can also simulate plants coming online after January 1, using similar equations.

Step 4 is to calculate the tax basis for the investment. Previous to the Tax Reform Act (TRA) of 1986, the tax basis was the sum over all years of the nominal-dollar direct construction expenditures (EBYCWP) calculated in Step 2 (adjusted for investment tax credits, as described below). However, any asset

coming online after 1986 that is not grandfathered under the provision must capitalize interest during construction. The tax basis can be calculated as follows:

$$EBASVL_y = 0$$

$$\text{for } y = EBSYR - ESLCP \text{ (i.e., year before construction begins)}$$

$$= EBASVL_{y-1} + EBYCWP_y + AVDINT_y$$

$$\text{for } y = (EBSYR - ESLCP + 1) \text{ to } EBSYR \text{ (i.e., construction period)}$$

(App5.B-9)

$$= EBASVL_{EBSYR}$$

$$\text{for } y = EBSYR \text{ to } (EBSYR + ESBKLF) \text{ (i.e., during service life)}$$

where

$EBASVL_y$	=	tax basis, year y
$EBYCWP_y$	=	nominal-dollar direct construction expenditures, year y
$AVDINT_y$	=	interest capitalized for tax basis (avoided interest), year y

No interest is capitalized for the tax basis unless the plant is covered under the TRA. The applicability of the TRA to a given plant is determined by a user-defined test based on the year the plant came online and first year of construction. When the new tax law does apply, the capitalized interest is calculated as follows:

(App5.B-10) $$AVDINT_y = (EBASVL_{y-1} + 0.5\ EBYCWP_y) \cdot ESRTNB_y$$

where

$AVDINT_y$	=	interest capitalized for tax basis (avoided interest), year y
$EBASVL_{y-1}$	=	tax basis, year y-1
$EBYCWP_y$	=	nominal-dollar direct construction expenditure, year y
$ESRTNB_y$	=	cost of new debt, year y

Step 5 is to calculate several accounts related to AFUDC. It is important to separate AFUDC into that financed by debt and that financed by equity, given by the following:

(App5.B-11)

$$ERFDCD_y = ESWACD_y \cdot AFUDC_y$$

$$ERFDCE_y = (1 - ESWACD_y) \cdot AFUDC_y$$

where

ERFDCD$_y$ =   debt-financed portion of AFUDC, year y

ERFDCE$_y$ =   equity-financed portion of AFUDC, year y

ESWACD$_y$ =   fraction of AFUDC representing debt costs, year y (see step 1)

While a plant is under construction, various interest expenses associated with construction of the plant accrue. For those plants not covered under the TRA, this interest expense provides a tax savings to the utility because interest is a deductible expense. The regulatory process attempts to capture this savings for ratemaking purposes and either flow it through immediately to ratepayers or defer it to a later period when the asset is in service by using the concept of the tax savings as a result of the debt portion of AFUDC, as follows:

(App5.B-12)

$$ERFFDC_y = ERFDCD_y \cdot ESFTXR \cdot ESFPDB$$

$$ERFXFDC_y = ERFDCD_y \cdot ESFTXR \cdot (1 - ESFPDB)$$

$$DAFDC_y = \sum_{i=K}^{y} ERXFDC_i$$

$$\textbf{for } y = \textbf{\textit{K}} \textbf{ to } \textbf{\textit{EBSYR}}$$

$$\textbf{where } \textbf{\textit{K}} = \textbf{\textit{EBSYR - ESLCP}} + 1$$

where

ERFFDC$_y$ =   generated tax savings from the debt portion of AFUDC that is flowed through, year y

ERFXFDC$_y$ =   generated tax savings from the debt portion of AFUDC that is deferred (normalized), year y

DAFDC$_y$ =   deferred tax savings from the debt portion of AFUDC, year y

ERFDCD$_y$ =   debt-financed portion of AFUDC, year y, (see above)

ESFTXR   =   federal tax rate (user input)

ESFPDB   =   flow-through percentage (expressed as a fraction) for AFUDC tax savings.

ESFPDB reflects the regulatory policy toward the tax savings and is a user input. The tax savings is generated while the plant is under construction. When the plant begins service, the deferred taxes, if any, are amortized over the service life of the plant and are calculated as follows:

(App5.B-13)

$$EBAFDC = DAFDC_{EBSYR} / ESBKLF$$

$$DAFDC_y = DAFDC_{y-1} - EBAFDC$$

$$\textbf{for } y = \textbf{\textit{EBSYR}} \textbf{ to } (\textbf{\textit{EBSYR}} + \textbf{\textit{ESBKLF}} - \textbf{1}) \textbf{ (i.e., over service life of plant)}$$

where

EBAFDC	=	annual amortization of deferred savings from the debt portion of AFUDC
$DAFDC_y$	=	deferred tax savings from the debt portion of AFUDC, year y
ESBKLF	=	book life of plant

Again, the calculations above pertaining to the tax savings from the debt portion of AFUDC relate only to plants not covered under the TRA of 1986. For plants covered under the TRA of 1986, there is no tax savings because interest must be capitalized for tax purposes. The interest capitalized for the purposes of calculating federal income taxes for regulatory purposes is therefore given as follows:

(App5.B-14) $$ERFFDC_y = ERFXFDC_y + AVDINT_y$$

where

$ERCIDC_y$	=	interest capitalized for the purposes of calculating federal income taxes for regulatory purposes, year y
$ERFXFDC_y$	=	generated tax savings from the debt portion of AFUDC that is deferred, year y
$AVDINT_y$	=	interest capitalized for tax basis, year y (see Step 4 above on p. 193)

Appendix 5.C. Depreciation

Depreciation expenses are calculated separately for financial (or book) and for tax purposes. Financial and tax depreciation differ for several reasons. First, book depreciation is calculated using the straight-line method while tax depreciation uses an accelerated method. The accelerated method yields higher depreciation in the early years of an asset's life followed by lower depreciation in later years than does the straight-line method (assuming all else equal). Second, capitalized allowance for funds used during construction (AFUDC) is depreciated for book purposes but not for tax purposes. Similarly, interest capitalized during construction for tax purposes is not depreciated for book purposes but is for tax purposes. Finally, the depreciation base for tax purposes must be lowered by one-half of the total investment tax credit earned during construction of the plant. The depreciation base for book purposes is not adjusted in this way.

ESDEPR = depreciation rate for financial purposes (usually 1/ESBKLF)

The methodology presented here is easily expanded to the n plant case and to existing plants.

Depreciation for financial purposes (ERBDE). Book depreciation is calculated using the straight-line method (net book value divided by remaining life) as follows:

(App5.C-1) $ERBDE_y - (ERBKVL - EBABDE_{y-1})/(ESBKLF - (YEAR-EBSYR))$

and

(App 5.C-2)
$$EBABDE_y = \sum_{i-EBSYR}^{y} ERBDE_i$$

$$\textbf{for } y = EBSYR \textbf{ to } EBSYR + ESBKLF - 1 \textbf{ (i.e., over service life of asset)}$$

where

$ERBDE_y$	=	book depreciation, year y
EBBKVL	=	book value of plant (includes any AFUDC).
$EBABDE_{y-1}$	=	accumulated book depreciation, previous year to year y
ESBKLF	=	book life of plant
YEAR	=	current year
EBSYR	=	year plant comes online
$EBABDE_y$	=	accumulated book depreciation, year y

The derivation of EBBKVL is discussed above in Appendix 5.A, Construction Work in Progress. When the plant retires (year EBSYR + ESBKLF), its book value is added to account ERBTIR and subtracted from EBABDE, which then has the effect of removing the plant from the books.

Depreciation for Tax Purposes. For tax purposes, depreciation is accelerated (in other words, allowed to be greater in early life of plant and less in later life) by two forces. First, utilities may depreciate the plant over a shorter period of time than the service life used for financial purposes. Second, an accelerated depreciation rate is used instead of a straight-line constant rate. The effect of accelerated depreciation is to lower tax liability in the earlier years of the plant life and raise it in the later years, compared with the straight-line method.

There are three different options in the EFP when determining tax depreciation rates: use those prescribed in the Tax Reform Act (TRA) of 1986; use those prescribed in the 1981 Economic Recovery Tax Act (ERTA); or use the sum-of-years-digits method. The method used for a particular asset is based on a user-specified test, which is a function of the year the construction of asset begins and the year the asset comes online. The sum-of-years-digits method is used for any asset that comes online before 1981. Because the first two methods are the most applicable approaches, they are discussed below.[65]

Under ERTA and TRA, tax depreciation schedules (now more properly called tax recovery schedules) are specified. The tax base, as modified under the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA), is reduced by one-half of the investment tax credit (discussed below) earned during the construction of the asset. For a given asset, the relevant recovery schedule is based on when the asset comes online and on what service life class the asset belongs. Most assets in EFP are depreciated over 15 years (some 10 years) under ERTA and 20 years (some 15 years) under TRA. Then, for the remaining years of the book life, tax depreciation is zero. The depreciation is given as follows:

(App5.C-3)
$$ERTDE_y = EXTXRS_y \cdot (EBASVL - 0.5 \cdot EBDITC)$$

$$\textbf{for } y = EBSYR \textbf{ to } EBSYR + ESBKLF \textbf{ -1 (i.e., during the service life of the plant)}$$

where

ERTDE$_y$	=	depreciation expense for tax purposes, year y
EBASVL	=	tax basis of asset
EXTXRS$_y$	=	depreciation rate prescribed by ERTA or TRA, year y
EBDITC	=	investment tax credits generated

EBASVL is discussed above. EBDITC is described below.

Absent accelerated depreciation, tax depreciation would be given as follows:

$$ERTDWO_y = ESDEPR \cdot (EBASVL - 0.5 \cdot EBDITC)$$

(App5.C-4)

$$\textbf{for } y = EBSYR \textbf{ to } EBSYR + ESBKLF \textbf{ -1 (i.e., during the service life of the plant)}$$

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[65] The approach for the sum-of-years-digits method is identical to that described except that the tax base is not reduced by one-half the investment tax credit.

where

ERTDWO$_y$ =   depreciation for tax purposes, without acceleration, year y

ESDEPR   =   straight-line depreciation rate

The difference between ERTDWO$_y$ and ERTDE$_y$ leads to tax savings in the early years of service followed by increased taxes in the later years. The regulatory authority determines the treatment of this difference for ratemaking purposes. Tax depreciation expense is given as follows:

(App5.C-5)
$$ERTDRG_y = ERTDWO_y \cdot (1 - ESFLPR) + ERTDE_y \cdot (ESFLPR)$$

$$\textbf{for y} = \textbf{\textit{EBSYR}} \textbf{ to } \textbf{\textit{EBSYR}} + \textbf{\textit{ESBKLF}} \textbf{ -1 (i.e., during the service life of the plant)}$$

where

ERTDRG$_y$ =   tax depreciation expense for regulatory purposes, year y

ESFLPR   =   percentage of tax savings as a result of acceleration depreciation that is flowed through

When the tax effects of accelerated depreciation are flowed through for regulatory purposes (ESFLPR = 1.0), ERTDRG is equal to ERTDE. In this case, revenue requirements directly show the effects of the acceleration. However, when the tax effects are normalized (ESFLPR = 0.0), then ERTDRG is equal to ERTDWO and thus the revenue requirements show no effects of the acceleration. Thus, in a flow-through scenario, revenue requirements are lower in the early years of the plant's service and higher in the later years, compared with revenue requirements in a normalized scenario (all else equal). This effect comes about because ERTDRG affects federal income taxes for regulatory purposes, which in turn affects revenue requirements.

Other useful quantities relating to this tax effect are given as follows:

(App5.C-6)
$$ERATSF_y = ESFTXR \cdot (ERTDE_y - ERTDWO_y) \cdot ESFLPR$$

$$ERATSD_y = ESFTXR \cdot (ERTDE_y - ERTDWO_y) \cdot (1 - ESFLPR)$$

$$DAD_y = \sum_{i=EBSYR}^{y} ERATSD_i \text{ for y} = EBSYR \text{ to } EBSYR + ESBKLF \text{ -1}$$

where

ERATSF$_y$ =   tax savings resulting from accelerated depreciation that are flowed through, year y

ERATSD$_y$ =   tax savings resulting from accelerated depreciation that are deferred, year y

DAD$_y$ =   provision for deferred taxes as a result of accelerated tax depreciation, year y

ESFTXR   =   Federal income tax rate

Appendix 5.D. Tax Issues

Excess deferred income taxes flowed back to ratepayers (EREDTF)

The 1986 Tax Reform Act (TRA) lowered the marginal federal income tax rate from 46% to 40% in 1987 and to 34% thereafter. One impact of the decrease in the marginal tax rate is to lower future reductions in deferred income taxes that will occur as assets complete their service lives.

As described in the preceding section, accelerated depreciation allowed for tax purposes leads to deferred income taxes for regulated utilities. Over the life of an individual asset, the level of deferred income taxes will increase in its early years and finally decrease to zero at the end of its service life. A complication arises, however, when the marginal tax rate decreases during the service life of an asset. The deferred taxes have been booked at the higher marginal tax rate but will now be paid at the lower tax rate. The difference between deferred income taxes now booked (under the 46% marginal tax rate) and what will ultimately be paid under the 34% marginal rate is referred as excess deferred income taxes. Excess deferred income taxes are given as follows:

$$\textbf{(App5.D-1)} \qquad EXCESS = \sum_{y=EBSYR}^{IYREDT} (ERTDE_y - ERTDWO_y) \cdot (ESFTXR_y - ESFTXR_{IYREDT})$$

These excess deferred taxes should be flowed through to the ratepayers. The Electricity Finance and Pricing (EFP) can flow back these taxes over the remaining lives of the assets or over any user-defined schedule of years.

The first step is to calculate the amount of deferred taxes that have accrued:

EXCESS	=	total excess deferred income taxes
$ERTDE_y$	=	depreciation expense for tax purposes, year y
$ERTDWO_y$	=	depreciation for tax purposes, without acceleration, year y
$ESFTXR_y$	=	federal income tax rate, year y (user input)
EBSYR	=	first year of service
IYREDT	=	year in which excess taxes are to be calculated (user input)

Now the amount of excess deferred income taxes flowed back to ratepayers in each year can be calculated as follows:

$$\textbf{(App5.D-2)} \qquad EREDTF_y = 0.0 \qquad\qquad \textbf{if } \textbf{y} < \textit{IYREDT}$$

$$= EXCESS/\ REMLIF \quad \textbf{if } \textbf{y} \geq \textit{IYREDT}$$

where

EREDTF$_y$	=	excess deferred taxes flowed back to ratepayers, year y
EXCESS	=	total excess deferred income taxes
REMLIF	=	remaining years of life for asset (ESBKLF - (IYREDT-EBSYR)).

The above equation flows back the excess deferred income taxes over the remaining life of the investment. Within EFP, it can also be flowed back over any user-defined schedule of years.

Provision for deferred income taxes (ERPRDF). The provision for deferred income taxes is the sum of the values of all deferred income taxes or deferred tax savings (excluding investment tax credits). For purposes of EFP, this provision includes the deferred taxes from accelerated depreciation and the deferred tax savings from the debt portion of the allowance for funds used during construction (AFUDC) on assets not affected by the TRA of 1986. The provision for deferred income taxes is given as follows:

(App5.D-3) $$ERPRDF = DAD + DAFDC - EREDTF$$

where

ERPRDF	=	provision for deferred income taxes
DAD	=	deferred income taxes as a result of accelerated depreciation
DAFDC	=	deferred tax savings from the debt portion of AFUDC
EREDTF	=	excess deferred taxes flowed back to ratepayers

Investment tax credit. The investment tax credit was established by Congress to encourage certain kinds of investments. The effect of the investment tax credit is to reduce the federal tax liability by the amount of the credit. The credit is generated during each year of the construction period for the plant. Previous to the Tax Reform Act of 1986 (TRA), the value of the credit each year was a percentage of construction expenses (excluding AFUDC) for that year. The investment tax credit was repealed under TRA. However, many assets currently under construction when the TRA was passed were grandfathered under the provision and will continue to receive the credit. For these assets, the effective investment tax credit rate will decrease over time. Within EFP, assets that receive the credit are determined by a user-specified test that is a function of the year in which the construction of the asset began and the year in which the asset enters service (in other words, any asset for which construction began before a user-specified year and which enters service before a user-specified year will continue to receive the credit). This test allows the capability to examine alternative assumptions regarding grandfathering.

The regulatory treatment of this tax savings is decided by the new regulatory commission. The credit can be flowed through immediately to lower the revenue requirement in the year it was generated or deferred and then amortized over the life of the plant. EFP handles any combination of these two treatments and is given as follows:

(App5.D-4)

$$ERFITC_y = EBYCWP_y \cdot ESRITC_y \cdot ESFLPR$$

$$XITCD_y = EBYCWP_y \cdot ESRITC_y \cdot (1 - ESFLPR)$$

$$EBDITC_y = \sum_{i=K}^{y} XITCD_i \quad \text{for } y = K \text{ to } EBSYR, \text{where } K = EBSYR - ESLCP + 1$$

where

$ERFITC_y$	=	generated ITC that is flowed through, year y
$XITCD_y$	=	generated ITC that is deferred, year y
$EBDITC_y$	=	deferred ITC, year y
$EBYCWP_y$	=	construction expenses, net of AFUDC, year y
$ESRITC_y$	=	investment tax credit rate, year y
$ESFLPR$	=	percentage of tax savings flowed through
$ESLCP$	=	length (in years) of construction period (including first year of operation)

When the plant begins service, any deferred ITC is amortized over the life of the plant as follows:

(App5.D-5)

$$ERAITC = EBDITC_{EBSYR} / ESBKLF$$

$$EBDITC_y = EBDITC_{y-1} - ERAITC$$

$$\text{for } y = EBSYR \text{ to } EBSYR + ESBKLF - 1$$

where

$ERAITC$	=	amortization of deferred investment tax credit
$EBDITC_y$	=	deferred ITC, year y, and
$ESBKLF$	=	service life of plant (user input).

Note that the investment tax credit is generated only on the direct construction expense, not on capitalized AFUDC.

Appendix 5.E. Sale/Leaseback Transactions

The sale and leaseback of an electric power plant is essentially a financial transaction that affects the timing of cost recovery, and frequently the capital cost, associated with the plant. It generally does not change the utility's responsibilities for operating and maintaining the plant or for selling the electricity it generates. Attractive for a variety of reasons, the sale/leaseback may be a creative way for a utility to circumvent constraints imposed by regulatory authorities, competition, bond indemnifications, or its tax position, benefitting both investors and ratepayers.

In the simplest form of a sale or leaseback, the utility sells a power plant to an institutional investor, then leases the plant back from the investor for equal semiannual rents over a term that is typically between 25 and 30 years. Regulators treat the rental payment as operating expenses, and the utility's revenue requirement no longer includes the return on capital or depreciation expense associated with the plant. The result is a flat revenue requirement over time, lower than conventional cost recovery in the short term, and higher toward the end of the lease.

For the algorithm presented below, the following values are input in the Electricity Finance and Pricing (EFP) for each sale/leaseback transaction to be modeled:

Variable	Description
IBYRSL	Year transaction is completed
SLPROC	Gross proceeds from transaction
BKGAIN	Gross gain on book value
SLTAXS	Utility income taxes on transaction
SLLP	Annual lease payment
SLTERM	Lease term

The methodology presented here applies to one transaction and is easily expanded to the n transaction case.

The first step is to calculate the book value of the plant sold, the net gain from the transaction, and the tax basis of the plant sold, as follows:

(App5.E-1)

$$SLBKVL = SLPROC - BKGAIN$$

$$SLGAIN = BKGAIN - SLTAXS$$

where:

$$SLASVL = SLPROC - SLTAXS / ESFTXR$$

SLBKVL   =   book value of plant sold

SLPROC   =   gross proceeds from transaction (input)

BKGAIN   =   gross gain on book value (input)

SLGAIN	=	net gain on book value
SLTAXS	=	utility income taxes on transaction (input)
SLASVL	=	tax basis of plant sold
ESFTXR	=	federal income tax rate (input).

The book value of the plant is subtracted from the total assets of utility plants in service, and the tax basis is subtracted from the utility tax accounts. This process is done within the EFP by creating an asset with a negative book value and tax basis equal in absolute value to that calculated above, which has the effect of removing the plant from utility books.

The remaining quantities are now calculated as follows:

(App5.E-2)

$$ESLPRC = SLPROC - SLTAXS$$
$$ESLLP = SLLP$$
$$ESLAGN = SLGAIN\ /\ SLTERM$$
$$ESLNDG_j = SLGAIN - j \cdot ESLAGN \textbf{ for } j = 1, ..., SLTERM$$
$$ESLLPN = ESLLP - ESLAGN$$

where:

ESLPRC	=	net of tax sales proceeds
ESLLP	=	annual lease payment
ESLAGN	=	amortization of gain
ESLNDG	=	net deferred gain from transaction
ESLLPN	=	net lease payment
SLPROC	=	gross proceeds from transaction (input)
SLTAXS	=	utility income taxes on transaction (input)
SLLP	=	annual lease payment (input)
SLGAIN	=	net gain on book value
SLTERM	=	lease term

Appendix 5.F. Rate Phase-in Plans

Almost all electric utilities in the United States have their electricity rates set by regulatory commissions at the local, state, or federal level (or any combination of these three). The most common method used by regulators to determine the appropriate rates is often referred to as original-cost, rate-of-return regulation. Under this methodology, the utility is able to charge rates that allow it to recover its operating and capital costs. Under this scheme, the rate impacts of the capital costs of a new asset coming online are greatest in its first year of service and decline thereafter over the life of the asset. Historically, the large increase in capital costs associated with a new plant were substantially, if not totally, offset by the lower operating costs obtained by utilizing the new unit.

Throughout the 1980s and early 1990s, however, many situations arose where, under traditional regulation, substantial rate increases occurred as new plants came online. These occurrences were caused by two major forces. First, the costs of new power plants rose substantially. This widely discussed phenomenon caused the capital costs of the plant to be substantially higher. Second, the savings derived from lower operating costs of the new plants had not been very great because of lower energy commodity prices as well as the power generation technologies leveling out in terms of efficiency. In addition, many areas of the country were overbuilt with capacity, again lowering the savings derived from the new plants. In many cases, a single utility brought online a new plant whose total costs accounted for a large fraction of its total assets, thus amplifying the two forces just described.

Given this pressure for dramatic increases in rates, alternative regulatory approaches were necessary. Even if a regulatory commission were to allow the large rate increases, the potential reaction of customers, particularly large customers, prevents such rate increases. The prospect of these customers leaving the service territory or bypassing the local utility through cogeneration or transmission wheeling is very real. Any exit of these customers requires the rates of remaining customers to increase even more, and ever-increasing rates and ever-declining sales become a possibility. In the interests of both the utilities and the ratepayers, a common approach to deal with this problem emerged and was referred to as a rate phase-in plan.

The idea of a rate phase-in plan is straightforward. For a number of years, rates are to be set at a level lower than would have been the case under traditional ratemaking. This period is followed by a number of years in which rates are higher than they would have been to allow the company to make up for the early years. After 2000, the Electricity Finance and Pricing (EFP) projections are no longer affected by these plans; however, the capacity to model them within the EFP is still available should phase-ins be used by regulated regions in the future.

For the algorithm presented below, the following values are input for each rate phase-in plan to be modeled:

IBYRPI   =   year rate phase-in plan begins

PIBKVL   =   book value of phase-in plant

DISPER   =   fraction of phase-in plant disallowed

LPI	=	length of phase-in plan
PIDFS$_y$	=	cumulative fraction of total cost to be phased-in in year y
PIRCS$_y$	=	fraction of remaining deferred revenues to be recovered in year y
IRDPI	=	logical variable indicating whether capitalized return is earned on deferred costs
PIBKLF	=	book life of phase-in plant
PITXBS	=	tax basis as a fraction of book basis for phase-in plant

The methodology presented here applies to one rate phase-in plan and is easily expanded to another rate plan case.

The first step is to calculate the total revenue requirement associated with the phase-in plant under traditional regulation for each year of the phase-in plan as follows:

(App5.F-1)
$$RR_y = \frac{PIBKVL \cdot (1 - DISPER) \cdot (1 - y/PIBKLF) \cdot ESPR/(1 - ESFTXR) + PIBKVL}{PIBKLF \cdot (1 + (1 - PITXBS) \cdot ESFTXR/(1 - ESFTXR))}$$

$$\textbf{for } y = 1, ..., LPI$$

where

RR$_y$	=	traditional revenue requirement of phase-in plant, year y
PIBKVL	=	book value of phase-in plant (input)
DISPER	=	fraction of phase-in plant disallowed (input)
PIBKLF	=	book life of phase-in plant (input)
ESRR	=	rate of return
ESFTXR	=	federal income tax rate (input)
PITXBS	=	tax basis as a fraction of book basis for phase-in plant (input)
LPI	=	length of phase-in plan (input)

Next, the costs to be deferred in each year are calculated as follows:

(App5.F-2)
$$EPIND_y = RR_y \cdot (1 - PIDFS_y) \cdot (1 - ESFTXR) - PIRCS_y \cdot EPIDEF_{y-1}$$
$$\text{for } y = 1, ..., LPI$$

where

$EPIND_y$	=	pre-tax deferred costs, year y
RR_y	=	traditional revenue requirement of phase-in plant, year y
$PIDFS_y$	=	cumulative fraction of total cost to be phased-in in year y (input)
$ESFTXR$	=	federal income tax rate (input)
$PIRCS_y$	=	fraction of remaining deferred revenues to be recovered in year y (input)
$EPIDEF_{y-1}$	=	cumulative deferred costs, year y-1 (see below).

Note that $EPIND_y$, calculated above will be positive during the initial period of the phase-in and will be negative during the final period of the phase-in. A negative value represents recovery from rate payers of deferred costs.

Next, the capitalized deferred return is calculated, if necessary (depends on value of IRDPI, an input described above), as follows:

(App5.F-3)
$$EPIRET_y = (EPIDEF_{y-1} + 0.5 \cdot EPIND_y) \cdot ESAFDC$$
$$\text{for } y = 1, ..., LPI$$

where

$EPIRET_y$	=	capitalized return on deferred costs, year y
$EPIDEF_{y-1}$	=	cumulative deferred costs, year y-1 (see below)
$EPIND_y$	=	pre-tax deferred costs, year y
$ESAFDC$	=	AFUDC rate

Next, cumulative deferred costs are calculated as follows:

(App5.F-4)
$$EPIDEF_y = EPIDEF_{y-1} + EPIND_y + EPIRET_y,$$
$$\text{for } y = 1, LPI$$

where

EPIDEF$_y$ =   cumulative deferred costs, year y

EPIND$_y$ =   pre-tax deferred costs, year y

EPIRET$_y$ =   capitalized return on deferred costs, year y

EPIDEF begins year 1 with a value of 0.0.

Finally, the net value of disallowed plant is calculated as follows:

(App5.F-5)

$$EDISNT_y = PIBKVL \cdot DISPER \cdot (1 - y/PIBKLF)$$
$$\textbf{for } y = 1, \ ..., PIBKLF$$

where:

EDISNT$_y$ =   net disallowed plant, year y

PIBKVL   =   book value of phase-in plant (input)

DISPER   =   fraction of phase-in plant disallowed (input)

PIBKLF   =   book life of phase-in plant (input).