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The Electricity Market Module of the National Energy Modeling System

Model Documentation Report

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Update Information

This report describes the version of the Electricity Market Module used for the *Annual Energy Outlook 2010*. It includes the following major changes:

- Reactivate provisions of the Clean Air Interstate Rule (CAIR), which was temporarily reinstated after being vacated by a court decision
- Incorporate structure for retrofitting existing coal-fired plants with carbon capture and sequestration (CCS) equipment
- Use a 30-year planning horizon and cost recovery period for capacity planning decisions
- Add capability to represent credit banking for Renewable Energy Standards (RES)

Additionally, subsequent to the publication of the 2009 model documentation the AEO2009 was updated to include the impacts of the American Recovery and Reinvestment Act of 2009. The following changes were made for the AEO2009 update and are also included in AEO2010:

- The production tax credit for wind was extended through 2012 and for other renwables through 2013
- To model the loan guarantees provided to new renewable technologies, the cost of capital was lowered by 2 percentage points for eligible plant types online by 2015
- To model the funding provided for smart grid technologies it was assumed that up to 3 percent of peak demand could be reduced through load shifting programs, and that line losses would fall slightly.
- As a result of the funding provided for the Clean Coal Power Initiative, it was assumed that one gigawatt of new coal with sequestration would come online in 2017.

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The Electricity Market Module of the National Energy Modeling System

1. Introduction

The National Energy Modeling System (NEMS) was developed to provide 20-to-25 year forecasts and analyses of energy-related activities. The 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, the EMM receives electricity demand 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 and estimates the actions taken by electric utilities and nonutilities to meet demand in the most economical manner. The 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 that model year.

The EMM represents the capacity planning, generation, transmission, and pricing of electricity, subject to: delivered prices for coal, petroleum products, natural gas, and biomass; the cost of centralized generation facilities; macroeconomic variables for costs of capital and domestic investment; and 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, nonutility supply and electricity trade are represented in the fuel dispatching and capacity planning submodules. Nonutility generation from cogenerators and other facilities whose primary business is not electricity generation is represented in the demand and fuel supply modules. All other nonutility generation is represented in the EMM. The generation of electricity is accounted for in 13 supply regions (Figure 3).

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.

The EMM also represents distributed generation that is owned by electricity suppliers. Consumer-owned distributed generation is determined in the end-use demand modules of the NEMS. The EMM considers construction, operating, and avoided transmission and distribution costs associated with distributed generation to evaluate these options as an alternative to central-station capacity.

The solution to the submodules of the EMM 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:

1. The electricity load and demand submodule processes electricity demand to construct load curves.

2. 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.

3. 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).

4. 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 has been designed to perform two major functions:

•Translate census division demand data into NERC region data, and vice versa

•Translate total electricity consumption forecasts into system load shapes

The demand for electricity varies over the course of a day. Many different technologies and end uses, each requiring a different level of capacity for different lengths of time, are powered by electricity. The 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.

Electricity Capacity Planning Submodule

The electricity capacity planning (ECP) submodule determines how best to 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 timing of the demand increase, the expected utilization of the new capacity, the operating efficiencies and the construction and operating costs of available technologies determine what technology is chosen.

The ECP evaluates retirement decisions for fossil and nuclear plants and captures responses to environmental regulations. It includes traditional and nontraditional sources of supply. The ECP also represents changes in the competitive structure (i.e.,deregulation). Due to competition, no distinction is made between utilities and nonutilities as owners of new capacity.

The utilization 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 (i.e., the highest demands on the system), which occurs infrequently. 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 baseload plants and cheaper to operate than peak load plants (such as a natural-gas fired combined cycle plant).

Figure 1. National Energy Modeling System

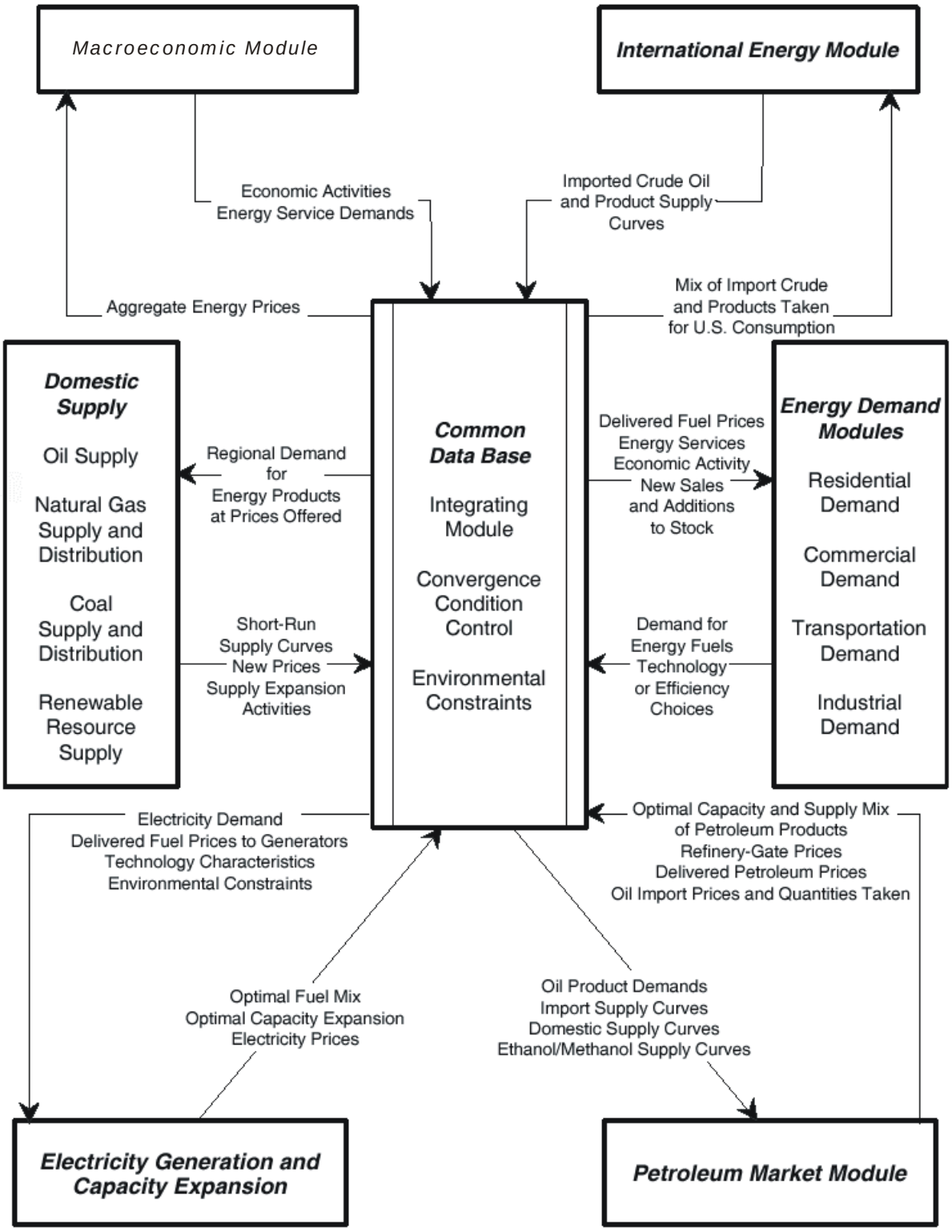
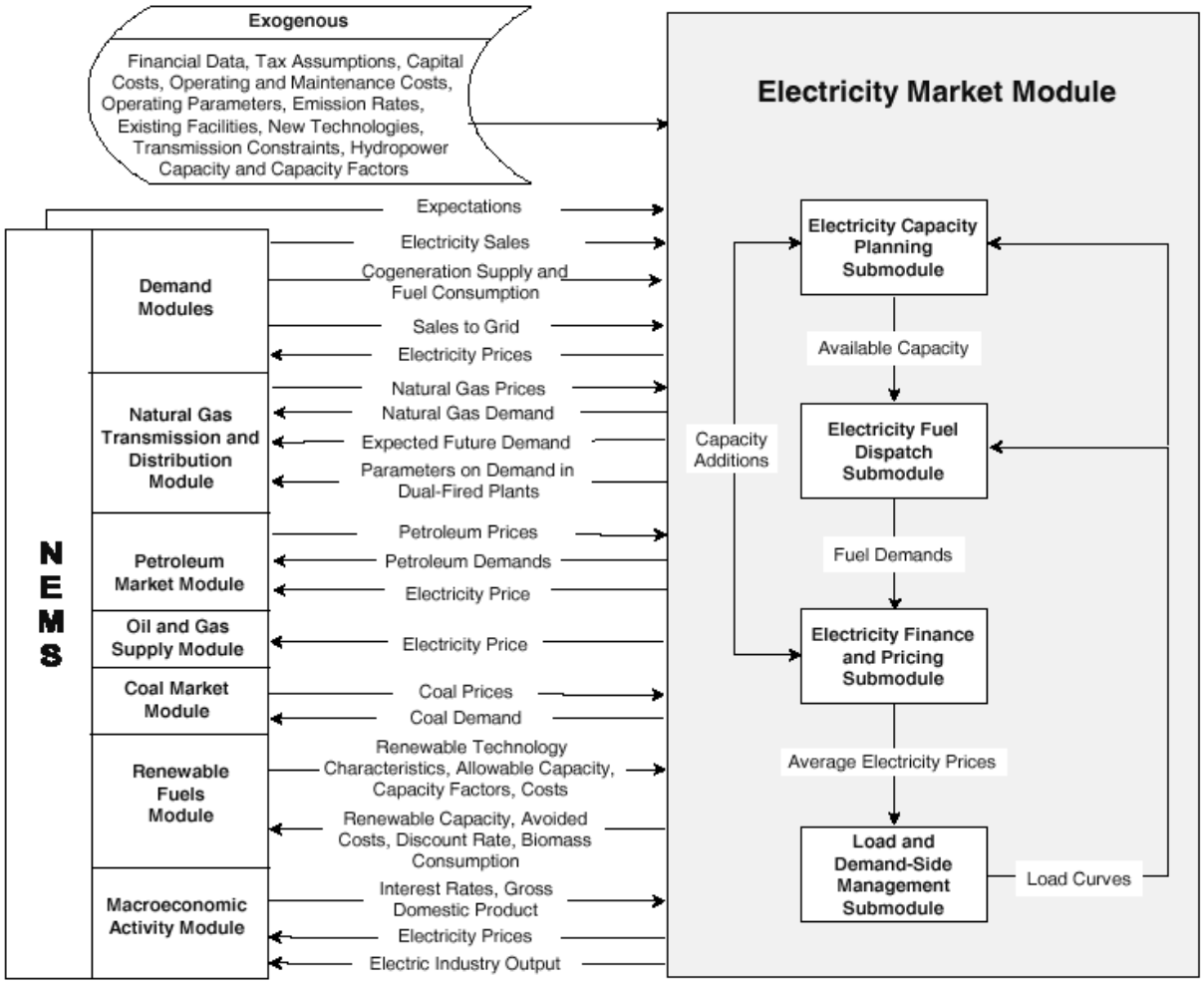
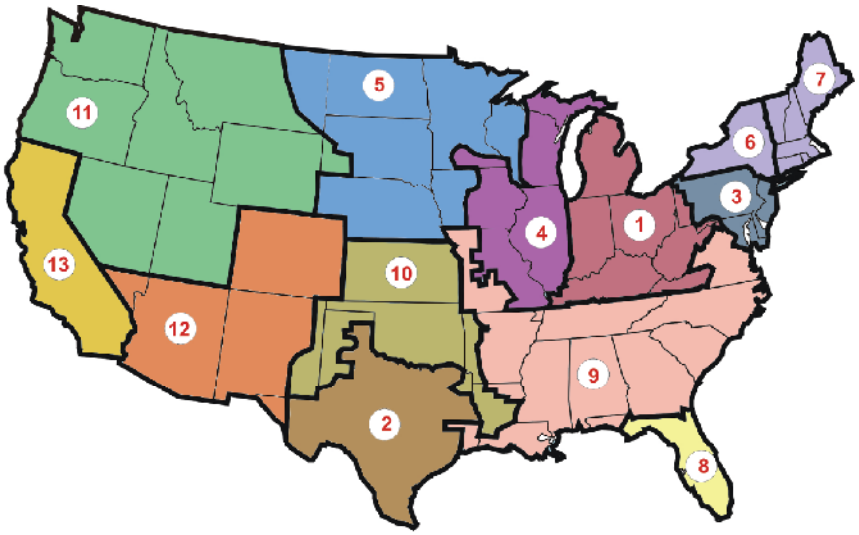


Figure 2. Electricity Market Module Structure



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	Renewable technology characteristics, allowable capacity, and costs	Operating parameters
Renewable capacity	Renewable capacity factors	Emissions rates
Avoided costs	Gross domestic product	New technologies
	Interest rates	Existing facilities
		Transmission constraints

Figure 3. Electricity Market Model Supply Regions



1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8. Florida Reliability Coordinating Council (FL)
9. Southeastern Electric Reliability Council (SERC)
10. Southwest Power Pool (SPP)
11. Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13. California (CA)

Technologies are compared on the basis of total capital and operating costs incurred over a 30-year period. As new technologies become available, they are competed against conventional plant types. Fossil-fuel, nuclear, and renewable generating technologies are represented. Base overnight capital costs are assumed to be the current cost per kilowatt for a unit constructed today. Regional multipliers are applied to base overnight costs to reflect cost differences in building in different regions of the country, mainly due to differences in labor rates. The base overnight costs have been increased over the past several years to bring the costs up to current levels as of early 2009, capturing recent cost increases. An annual cost factor is calculated based on the macroeconomic variable tracking the metals and metal products producer price index, creating a link between construction costs and commodity prices. Using 2009 as the base year, the factor results in the base costs continuing to increase for the first few years of the forecast, and then gradually declining by a total of 18% by 2035, due to the projected decline in the macro index.

Uncertainty about investment costs for new technologies is captured in the ECP 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 due to "learning-by-doing".[1] Learning factors are calculated separately for each of the major design components of the technology. For new technologies, cost reductions due to learning also account for international experience in

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

building generating capacity. Generally, overnight costs for new, untested components are assumed to decrease by a specified percentage for each doubling of capacity for the first three doublings, by 10 percent for each of the next five doublings of capacity, and by 1 percent for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1 percent for each doubling of capacity.

Capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new technologies are assumed to contribute to reductions in capital costs for units that are installed in the United States to the extent that (1) the technology characteristics are similar to those used in U.S. markets, (2) the design and construction firms and key personnel compete in the U.S. market, (3) the owning and operating firm competes actively in the United States, and (4) there exists relatively complete information about the status of the associated facility. If a new foreign unit does not satisfy one or more of these requirements, it is given a reduced weight or not included in the learning effects calculation.

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. Therefore, the ECP uses a market-sharing algorithm to adjust the initial solution and reallocate some of the capacity expansion decisions to technologies that are "competitive" but do not have the lowest average cost.

The ECP submodule also determines whether to contract for new firm power imports from Canada and from neighboring electricity supply regions. Imports from Canada are represented using supply curves developed from cost estimates for potential hydroelectric projects in Canada. Imports from neighboring electricity supply regions are modeled in the ECP based on the cost of the unit in the exporting region plus the additional cost of transmitting the power. Transmission costs are computed as a fraction of revenue.

After building new capacity, the submodule passes total available capacity to the electricity fuel dispatch submodule and new capacity expenses to the electricity finance and pricing submodule. The technologies are summarized in the following table:

Fossil Fuel Fired	Nuclear
Existing Coal without FGD	Conventional nuclear
Existing Coal with FGD	Advanced nuclear
New pulverized coal with FGD	
Advanced clean coal technology	
Advanced clean coal technology	**Renewables**

with sequestration Gas/oil steam Conventional gas/oil combined cycle Advanced combined cycle Advanced combined cycle with sequestration Conventional combustion turbine Advanced combustion turbine Fuel cells Distributed generation *(FGD = flue gas desulfurization)*	Conventional hydropower Geothermal Solar-thermal Solar-photovoltaic Wind Wood 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 purchased-power agreements, fuel prices, and load curves, the EFD minimizes variable costs as it solves for generation facility utilization and economy power exchanges to satisfy demand in each time period and region. The submodule 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 and nitrogen oxides from generating units and the engineering characteristics and maintenance requirements of units serve as constraints. During off-peak periods, the submodule institutes load following, which is the practice of running plants near their minimum operating levels rather than shutting them down and incurring shutoff and startup costs. Finally, the annual operation of plants for each region is separated into four time periods to reflect the seasonal variation in electricity demand.

Interregional economy trade (i.e., transactions that are not firm contracts) is also represented in the EFD. The simultaneous dispatch decision across all regions linked by transmission network allows generation in one region to satisfy electricity demand in an adjacent region, resulting in a cost savings. Economy trade with Canada is determined in a similar manner as interregional economy trade. Surplus Canadian energy is allowed to displace 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 and operating expenses and revenues from trade are reported to the electricity finance and pricing submodule.

Electricity Finance and Pricing Submodule

The costs of building capacity, buying power, and generating electricity are tallied in the Electricity Finance and Pricing (EFP) submodule, which 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. 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 Report of Public Electric Utilities"), cost estimates for new plants, fuel prices from the NEMS fuel supply modules, unit operating levels, plant decommissioning costs, plant phase-in costs, and purchased power costs, the EFP submodule calculates total revenue requirements for each area of utility operation—generation, transmission, and distribution. Revenue requirements shared over sales by customer class yield the price of electricity for each class. In addition, the submodule generates detailed financial statements.

For those States that have deregulated or plan to deregulate their electricity generation markets, the 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. 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. The competitive price also includes a "reliability price adjustment," which represents the value consumers place on reliability of service when demands are high and available capacity is limited. 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.

The delivered price of electricity calculated in the EFP for each EMM region is passed 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 or not a given EMM region has committed to competitive electricity markets, what percent of the region's sales are in competitive markets, and how long the region has been competitive.

Emissions

The EMM tracks emission levels for sulfur dioxide (SO_2), nitrogen oxides (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) and the Clean Air Interstate Rule (CAIR). Due to a court decision that vacated the Clean Air Mercury Rule (CAMR), this regulation is not included in the AEO2010 projections. Although CAMR is no longer valid, several States have plans to implement mercury standards that are generally based on best available control technology. The AEO2010 includes these state-level regulations.

Some current and proposed regulations utilize an allowance trading market. The trading system allows a utility with a relatively low cost of compliance to sell its excess compliance (i.e., the degree to which its emissions per unit of power generated are below maximum allowable levels) to utilities with a relatively high cost of compliance. The trading of emissions allowances does not change the national aggregate emissions levels, but it does tend to minimize the overall cost of compliance. In the EMM, trading is assumed to occur at the regional level, with those regions having a low cost of compliance allowed to sell excess allowances to the higher-cost regions. The EMM also has the ability to track and limit emissions of carbon dioxide.

2. Electricity Load and Demand Submodule

This chapter documents the Electricity Load and Demand (ELD) submodule of the EMM. The primary purpose of the ELD submodule is to translate census region annual electricity consumption forecasts from the NEMS demand submodules into the NERC region 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 has been designed to perform two major functions:

- Translate census division annual demand data into NERC region annual data, and vice versa
- Translate annual electricity consumption forecasts into seasonal and time-of-day load shapes (load duration curves)

Model Objectives

The primary objective of the ELD is the preparation of 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 (i.e., system load shapes) at the regional level together with load shape information for individual end-uses (i.e., heating, lighting, air conditioning, etc.) the ELD constructs seasonal and time of day load shapes for each year of NEMS operation.

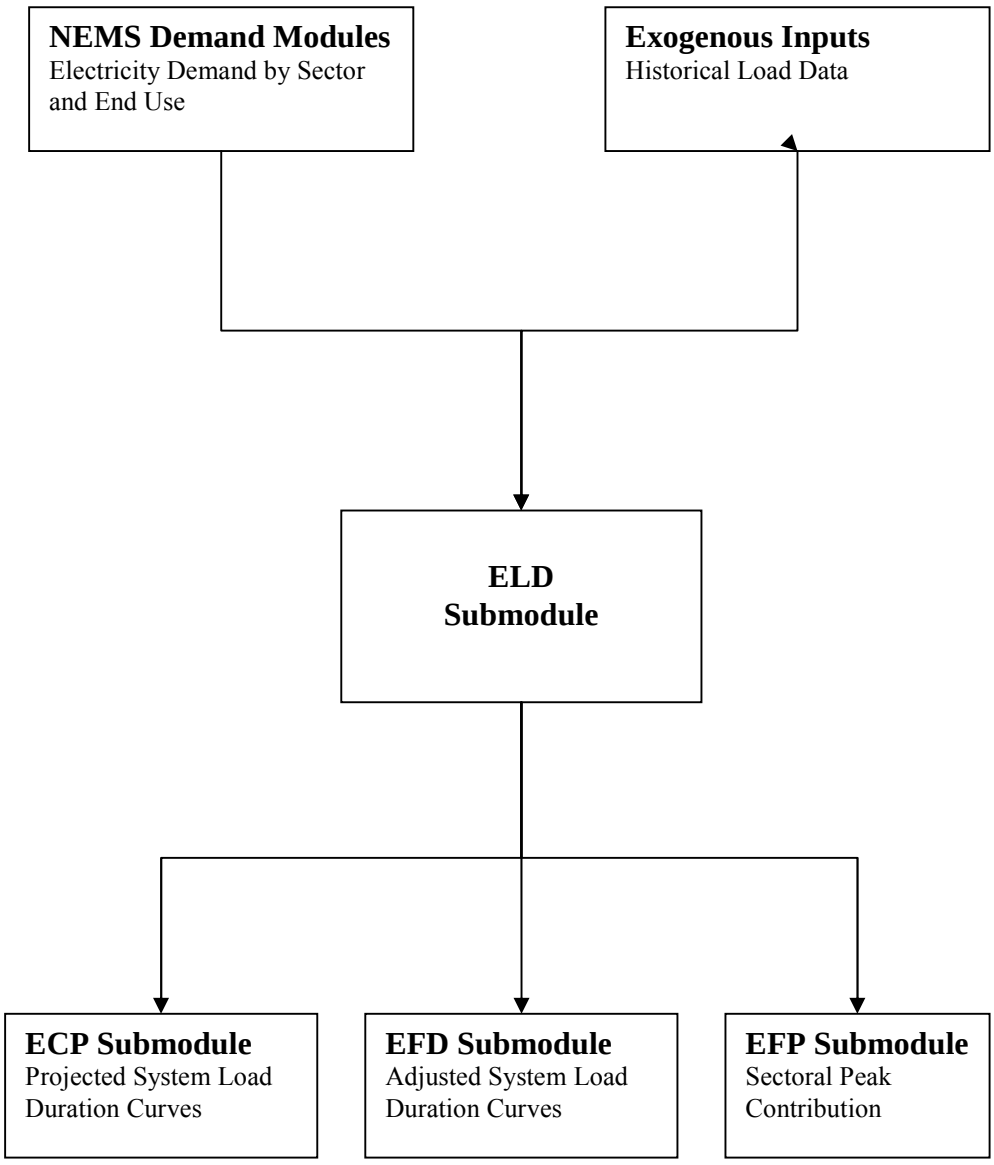
Level of Aggregation

As with all of the EMM, the ELD operates at a 13 region level. The regions are based on the North American Electric Reliability Council (NERC) Regions and Subregions. Of the 10 NERC Regions, eight are represented in their entirety: ECAR, MAAC, MAIN, MAPP, SPP, ERCOT, SERC and FL. The other regions are formed by splitting or combining several of the NERC regions. In the Northeast Power Coordination Council (NPCC), the New England states constitute one region and New York represents another (NY). The Rocky Mountain Power Area (RMPA) and Arizona-New Mexico-Southern Nevada Power Area (AZNMSNV) Subcouncils have been combined into one region. The Northwest Power Pool Area (NWP) and California Power Area (CA) form the other two regions. Because of the topography of the electrical grid in the U.S. using NERC Regions and Subregions allows for a better representation of electricity markets 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 (Inter-Module linkages). Figure 4 displays these linkages. Only the ELD links are shown in the figure.

Figure 4. ELD Linkages With Other Modules



Intra-Module Data Linkages

Within the EMM the key linkages to the ELD are with the Electricity Capacity Planning (ECP) and Electricity Fuel Dispatch (EFD) submodules. As mentioned previously, the ELD submodule supplies system load duration curves to both the ECP and the EFD. It also provides information on sectoral peak demands to the 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). Utilizing these forecasts, the ELD develops system load shapes for each of the 13 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 vast 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.

Electricity Fuel Dispatch Submodule

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

Electricity Finance and Pricing Submodule

The ELD passes the peak load demands from the end-use sectors to the EFP. In competitive markets, the capacity (reliability) component of price is allocated to the sectors based on their respective contributions to the overall peak load.

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 and Rationale

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 impact the types of capacity that can be economically developed and the fuels that will be used to generate electricity. It is for these reasons that the ELD has primarily been developed to translate the annual electricity demand values generated by the NEMS demand modules into the regional, seasonal, and time-of-day patterns needed by the EMM.

Model Structure

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

Given this information, the ELD then performs its two main tasks.

- Mapping of 9 Census Division demand estimates into 13 EMM Regions
- Development of system load shapes for the ECP and EFD

The subsections that follow discuss each of these tasks in order.

Mapping of Demand Estimates into EMM Regions

One of the functions of the ELD submodule is to provide the interface for demand data between the NEMS demand modules and the EMM module. This component conducts two tasks. The first task is the translation of the sectoral demand estimates that are produced by 9 Census divisions within the NEMS demand modules into the 13 EMM Regions.

Development of System Load Shapes

This section describes the methodology used to construct electric utility load curves in the ELD. The end result of these calculations is the seasonal and annual load duration curves for each of the 13 EMM regions. The overall methodology can be described as consisting of two steps:

- Step 1: Forecasting regional chronological hourly loads for each hour of the year
- Step 2: Sorting Hourly loads to produce load duration curve representations for ECP and EFD.

Both of these steps are divisible into smaller sub-parts, and these are described in detail below.

Forecasting Regional Chronological Hourly Loads. The ELD submodule develops 8760 hour system load curves to reflect different appliance usage patterns (e.g., space heating demands may be higher at certain hours, while at other times the water heating load may dominate the LDC). Investments in different utility demand side management programs, will similarly yield results that vary by season and time of day. The impact of energy efficiency improvement type demand-side management (DSM) options is already incorporated in the analysis, through appliance stock adjustments, accomplished by the demand forecasting modules. In constructing and modifying

these curves, the ELD uses a combination of load shape data from various sources and historical load shape data collected by the North American Electric Reliability Council (NERC).

Many utilities use such chronological hourly load shapes (load profiles) to predict their customers' demand patterns. The hourly system load curves are developed by these utilities from the bottom up by adding together the hourly loads of individual end-uses - i.e., refrigerator, air conditioners, etc. - 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. At present, 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 is available. This 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 (e.g., not all refrigerators in an area follow the same usage pattern). Efforts are underway, which will make better quality data available in coming years. One example is the new Central Electric End-use Data (CEED), run by the Electric Power Research Institute (EPRI), whose purpose is to collect, catalogue and disseminate such information. The ELD will take advantage of such information as it becomes available.

There are two different approaches used within the ELD model for the forecasting of hourly loads, namely, the Basic Approach and the Delta Approach. In the Basic Approach (that is the more intuitive one), 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 for the development of the DSM Program Load Impact Curves and the demand sector load curves (which are necessary for finding the sectoral peak loads that are required by the EFP model).

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.

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 forecasted. Next the hourly loads of each end-use are summed to yield the forecast of system load at the customers' meter (i.e., hourly system sales). The final step is to simulate transmission and distribution losses. The regional hourly loads are calculated as the sum of hourly system sales and transmission and distribution losses. Each of these sub-steps is described below.

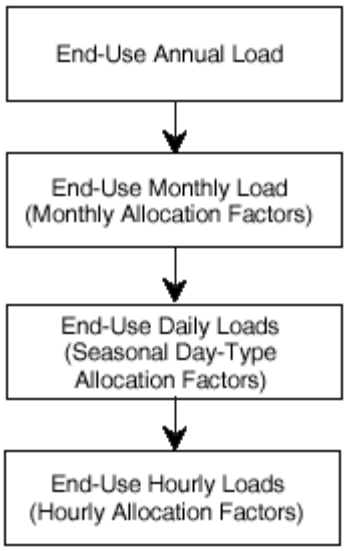
Computing End-Use Hourly Loads—In projecting the hourly loads for an end-use, the ELD requires two major inputs:

- annual sales forecast
- typical load shapes that allocate end-use annual load to each hour in a year.

The annual sales forecast is determined endogenously in NEMS. The annual sales forecast for each of the base end-uses is passed to the ELD from the NEMS demand models. The typical load shapes for each end-use are an exogenous input to ELD. Typical load shapes are input by month and by day-type (peak day, week day, and week end).

The first stage in the development of end-use hourly loads is to prepare, for each end-use, a normalized hourly load profile. This is a one time procedure for the entire NEMS analysis, and so it was put into the ELD submodule's pre-processor, LSRDBMGR. Computing end-use normalized, hourly load profiles from the end-use inputs is a three step process. Figure 5 gives a flowchart of the three steps. All three steps utilize data that are supplied on a standardized load shape representation (LSR) file. Each LSR file contains a complete set of data describing a single end-use. The LSRs in the current version of the ELD come from the RELOAD database.

Figure 5. Steps in the Computation of End-Use Hourly Loads



The first step is to map the annual sales forecast into a set of monthly sales forecasts. This is accomplished based on a set of exogenous input monthly allocation factors. The monthly allocation factors are a set of weights assigned to each month. These weights inform the ELD submodule of the relative energy usage from month to month. For example, the input data could assign January the weight of 1.0, and if February uses 20 percent more energy then its weight would be 1.2. Similarly, if September's usage was 15 percent less, its weight would be 0.85. In this way the inputs can define the relative energy usage from month to month. Another way of assigning weights is to define the annual energy usage as 100 percent. Then each month's weight is given by its percentage contribution to the annual load. Thus, if 20 percent of the annual load is used during January, its weight could be 20 and then if September is responsible for only 5 percent of annual energy usage its weight would be 5.

The second step of the conversion is to allocate monthly loads to daily loads. This is done in a similar construct as that by which annual load is assigned to monthly load allocations. It is accomplished with a set of day-type allocation factors which specify the relative energy use for each day type. All days within a month assigned to a given day-type are assumed to have the same load.

The third and final step in the conversion is to divide each day's load into a set of hourly loads for that day. This is done in the same manner as annual load is allocated to monthly load. The only difference is that the hourly allocation factors (sets of these factors are referred to as 24-hour load shapes in the data input file) are provided based upon season and day-type. Thus, instead of providing a set of allocation factors for each day of the forecast year, or only one set

that applies for every day in the year, the user can provide a 24-hour load shape for each combination of season and day-type in the forecast year. Therefore, when dividing the daily load into hourly load, the relative energy usage ratios are selected based upon the day-type the day is assigned to and the season to which the month that the day falls into is assigned.

It is the complete set of hourly loads that describes the load shape of the end-use. Thus, these computational techniques must be applied to each hour within each day within each month in the forecast year as they are defined in the calendar file. The exact computations performed during each of these three steps are discussed below. The vectors used in the transformation of annual demand in to hourly demand were developed through analysis of historical data.

Allocation of Annual Load to Monthly Load—Allocation of annual load to monthly loads is accomplished in a two step process described below. Since the monthly allocation factors supplied in the LSR files may not be normalized, first, the normalization factor is computed. Second, this normalization factor is applied to each monthly allocation factor. This yields the percentage of annual load assigned to each month.

The normalization factor is computed by summing the monthly allocation factors for each month. Therefore,

(2-1)
$$DMNF = \sum_{m=1}^{12} DMAF_m$$

Where:

DMNF = the normalization factor for monthly allocation

$DMAF_m$ = the monthly allocation factor for month m (input)

Next this normalization factor is used to normalize the monthly allocation factors. Therefore,

(2-2)
$$DNMAF_m = \frac{DMAF_m}{DMNF}$$

Where:

$DNMAF_m$ = the normalized monthly allocation factor for month m

$DMAF_m$ = the monthly allocation factor for month m

DMNF = the normalization factor for monthly allocation

Allocation of Monthly Load to Daily Load—Allocation of monthly load to daily load is accomplished by performing a weighted normalization on the daily allocation factors. The daily allocation factor set (an allocation factor for each day-type) is selected based upon the season to which the month is assigned. A daily load amount is computed for each day-type. This daily load is the load for every day in the month of that day-type. The allocation factors represent relative energy usage on a typical day of each day-type. The weighted normalization is performed using the number of days assigned to each day-type as weights.

There is a set of daily load allocation factors input for each season of the year. These are computed from the LSRs. Each seasonal set includes an allocation factor for each day-type in that season. The different months are allocated to different seasons, and the corresponding seasonal set is used to allocate the daily load to the different day types in the month. Thus, the set

of daily allocation factors vary by season though the computations will be performed for each month. Hence, more than one month may use the same set of allocation factors, if they are assigned to the same season.

The weighted normalization of daily allocation factors is accomplished in three computations. First, the weighted daily allocation factors are computed as follows:

(2-3) $$DWDAF_{mt} = (ND_{mt} \times DDAF_{mt})$$

Where:

$DWDAF_{mt}$ = the weighted daily allocation factor for day-type t in month m

ND_{mt} = the number of days in month m that are assigned to day-type t

$DDAF_{mt}$ = the daily allocation factor for day-type t in month m (input)

Then the normalization factor is computed as the sum of these weighted allocation factors. Therefore,

(2-4) $$DDNF_{m} = \sum_{t=1}^{NDT} DWDAF_{mt}$$

Where:

$DDNF_{m}$ = the normalization factor for daily allocation in month m

NDT = the number of day-types

$DWDAF_{mt}$ = the weighted daily allocation factor for day-type t in month m

Finally, the normalized allocation factor (percent of monthly allocation) for each day-type is computed by dividing each daily allocation factor by the normalization factor. Therefore,

(2-5) $$DNDAF_{mt} = \frac{DDAF_{mt}}{DDNF_{m}}$$

Where:

$DNDAF_{mt}$ = the normalized daily allocation factor for day-type t in month m

$DDAF_{mt}$ = the weighted daily allocation factor for day-type t in month m

$DDNF_{m}$ = the normalization factor for daily allocation in month m

The last step is to combine these normalized daily allocation factors with the monthly allocation factors. This is accomplished by multiplying the daily normalized allocation factors times the monthly normalized allocation factors.

(2-6) $$DDTL_{mt} = DNDAF_{mt} \times DNMAF_{m}$$

Where:

$DDTL_{mt}$ = fraction of the annual load allocated to each day assigned to day-type t in month m

$DNDAF_{mt}$ = the normalized daily allocation factor for day-type t in month m

$DNMAF_{m}$ = the normalized monthly allocation factor for month m

Allocation of Daily Load to Hourly Load—Allocation of daily load to hourly loads is accomplished by normalizing the hourly allocation factors (each set of hourly allocation factors is referred to as a 24-hour load shape) and combining the result with the daily allocation of load. This can be broken down into a three step process. First, the normalization factor is computed. Next, this normalization factor is applied to each hourly allocation factor. This yields the percentage of daily load assigned to each hour. Finally, these hourly allocation percentages are multiplied by fractions of total annual load allocated to each day, thus yielding fractions of annual load allocated to each hour of the year.

A set of hourly load allocation factors (24-hour load shapes) is supplied on an LSR file. There is one set input for each combination of season and day-type, and each set includes 24 hourly allocation factors. The set that is used for each day is the one for the day-type to which the day is assigned and the season to which the month that the day falls into is assigned. Note that although the equations presented in this section refer to information that varies by month and day-type, the actual information input by the user varies by season and day-type, respectively.

The normalization factor is computed by summing the hourly allocation factors for each hour of the day. Therefore,

(2-7) $$DHNF_{mt} \sum_{h=1}^{24} DHAF_{mth}$$

Where:

$DHNF_{mt}$ = the normalization factor for hourly allocation for day type t in month m

$DHAF_{mth}$ = the hourly allocation factor for hour h of day type t in month m

Next this normalization factor is used to normalize the hourly allocation factors. Therefore,

(2-8) $$DNHAF_{mth} = \frac{DHAF_{mth}}{DHNF_{mt}}$$

Where:

$DNHAF_{mth}$ = the normalized hourly allocation factor for hour h of day type t in month m

$DHAF_{mth}$ = the hourly allocation factor for hour h of day type t in month m

$DHNF_{mt}$ = the normalization factor for hourly allocation for day type t in month m

Finally, each normalized hourly allocation factor is multiplied by the fraction of annual load, allocated to a given day, yielding a fraction of annual load allocated to each hour. Thus,

(2-9) $$DHL_{mdh} = DNHAF_{mth} \times DDTL_{mt}$$

Where:

DHL_{mdh} = fraction of annual load allocated to hour h of day d in month m

$DNHAF_{mth}$ = the normalized hourly allocation factor for hour h of day type t in month m

$DDTL_{mt}$ = fraction of the annual load allocated to each day assigned to day-type t in month m

Finally the normalized hourly load profile is given as:

(2-10) $$\{DHL_{mdh} \text{ such that } m = 1,2,\ldots NM; d = 1,2,\ldots ND_m; h = 1,2,\ldots 24\}$$

Where:

DHL_{mdh} = fraction of annual load allocated to hour h of day d in month m

NM = the number of months in the forecast year

ND_m = the number of days in month m of the forecast year

Such a set of values is developed from the LSR files by the LSRDBMGR preprocessor for each end-use, and stored on the direct access file. Each record on the file defines hourly distribution of annual load for one end-use. To speed up computations, the ELD model refers to the values on each record using the hour-in-the-year index as explained below.

(2-11) $$DistLo_e = DHL_{mdh}$$

Where:

DistLo(h) = fraction of annual load allocated to hour h of a year for end-use e

DHL_{mdh} = fraction of annual load allocated to hour h of day d in month

Combining End-Use Load Shapes—The second sub-step of the methodology is to combine the end-use hourly load shapes into one system load shape for the forecast year. The combination of end-use hourly loads is accomplished by an hour-by-hour summation over the forecast year. This procedure is conducted for each EMM region as follows:

(2-12) $$SYLOAD(H) = \sum_{e=1}^{NUSES} DistLo_e(H) \times load_{1e}$$

Where:

SYLOAD(H) = system load in hour H

$NUSES_e$ = number of end-uses for end-use e

$load1_e$ = annual load forecast 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 (i.e., lighting, heating, refrigeration, etc.). Thus, it is the hourly sales for the system. The 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 is accomplished by multiplying the hourly load values in the EMM region system load curves by the exogenously defined transmission and distribution loss factor. Since the values are supplied on the input by EMM region and then are applied to the EMM regional loads, no mapping of the multipliers from Census to EMM regions is required.

A transmission and distribution loss factor represents an average of an EMM region's percentage of energy lost during transmission and distribution. The values of those factors are quite stable at a regional level because they reflect the efficiency of a transmission and distribution network as a whole. Unless considerable changes in voltages and distances of transmission take place they do not change significantly. Therefore, those factors are modeled in ELD as fixed for the entire planning horizon.

Modification to the Basic Methodology: The purpose of this section is to describe and demonstrate an alternative formulation of system load shape forecasting which allows the ELD to take advantage of the initial system data base, yet still produce reasonable forecasts. This approach is termed the Delta Approach.

The essence of the Delta Approach is to introduce a new end-use into the data base. This end-use is the current utility system load for which actual load data is available. Load shape information for this "end-use" will be historical system hourly loads. The resulting hourly load forecast of this formulation is a shape which in the early forecast 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:

(2-13) $$SYLOAD(H) = DistLo_s(H) \times SystemLoad + \sum_{e=1}^{NUSES} DistLo_e(H) \times load_{2e}$$

Where:

SYLOAD(H)	=	system load in hour H
$load2_e$	=	difference between the end-use's annual energy consumption in the current year and the base year ("delta" approach — positive or negative value)
SystemLoad	=	base year total system load
$DistLo_e(H)$	=	hourly end-use load shapes
$DistLo_S(H)$	=	historical hourly system load shape
NUSES	=	number of end-uses
s	=	system

Note: If all data on load shapes were perfect this would give same answer as basic approach, but as explained previously the end-use load shape data are not of sufficient quality for this to be true.

While:

(2-14) $$Load_{2e} = load_{1e} - BaseYrLd(e, RNB)$$

Where:

BaseYrLd(e,RNB) = base year load for end-use e in EMM region RNB

$load1_e$ = current year load for end-use e

$load2_e$ = difference between the end-use's annual energy consumption in the current year and the base year ("delta" approach — positive or negative value)

Development of Load Duration Curves for the ECP and EFD Modules

Load Duration Curves (LDCs), are used by both the ECP and the EFD Modules. An LDC consists of a discrete number of blocks. The height of each block gives the forecasted 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, due to the differing needs of the ECP and EFD modules, the LDCs created for each of these modules, differ. The sections below describe the specific steps used to develop the LDCs.

Load Duration Curves for the ECP Module

Demand for electricity is input to the ECP module by means of approximated LDCs, specified for each of the 13 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 dramatically. Typically analyst judgement 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 step, a different sorting criteria is followed. In the first step, the 8760 hours that make up a year are assigned to a number of "segments" 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 block has a specified percentage of the hours assigned to that segment. Two types of blocks are allowed: "regular" blocks, and "peak" blocks. The height of a regular block is equal to the average load of hours assigned to that block, while the height of a peak block is equal to the highest hourly load for hours assigned to that block.

The width of each block is equal to 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 the EFD Module

LDCs for use by the EFD module, are created for each season and for each of the 13 EMM regions. The steps involved in their creation are exactly the same as in the case of the ECP LDCs. The only difference is that the process is performed for each season separately.

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3. Electricity Capacity Planning Submodule

This chapter documents the objectives and analytical approach of the Electricity Capacity Planning Submodule (ECP), which determines 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

The 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. The ECP contains a dispatching component so that planning decisions consider the tradeoff between investment and operating costs.

The ECP examines strategies for complying with environmental legislation, such as the Clean Air Act Amendments of 1990 (CAAA). Planning options for achieving the sulfur dioxide (SO_2) emissions restrictions in the CAAA include installing pollution control equipment on existing power plants and building new power plants with low emission rates.[9] These methods for reducing emission are compared to 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. Consequently, the decision to build a particular capacity type must consider the cost (if any) of obtaining sufficient allowances. This could involve purchasing allowances or over complying at an existing unit. The ECP also represents restrictions on nitrogen oxide (NO_x), mercury (Hg), and carbon dioxide emissions.

Potential options for new generating capacity include central-station plants using fossil-fuel, nuclear, and renewable power (including intermittent technologies such as solar and wind) and distributed generation capacity. The ECP also includes construction of new generation and transmission capacity in Canada for export to a U.S. region and/or in one U.S. region for export to another U.S. region. As new technologies become available, they compete with conventional plant types as sources of supply in the ECP. The ECP contains a technology penetration component, which represents changes in cost and performance characteristics due to learning effects, risk and uncertainty.[10] The ECP also contains a market-sharing algorithm and evaluates plant retirement decisions.

The ECP also includes the option to build a new demand storage technology to simulate load shifting, through programs such as smart meters. This is modeled as a new technology build, but with operating characteristics similar to pumped storage. The technology is able to decrease the load in peak slices, but must generate to replace that demand in other time slices. There is an input factor that identifies the amount of replacement generation needed, where a factor of less than 1.0 can be use to represent peak shaving rather than purely shifting the load to other time

[9] For a more detailed description of the Clean Air Act Amendments, see Energy Information Administration, *Component Design Report Electricity Fuel Dispatch* (Washington, DC, May 1992).

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

periods. The AEO2010 assumes that this demand storage technology could be used to offset up to 3 percent of peak demand by 2035.

Model Purpose

Model Objectives

The purpose of the ECP is to determine how the electric power industry will change its mix of generating capacity over the forecast horizon. It considers investment decisions for new capacity and evaluates retirement decisions for fossil and nuclear plants. The ECP represents changes in the competitive structure (i.e., deregulation). Due to competition, no distinction is made between utilities and nonutilities as owners of new generating capacity. The ECP also captures changes to plants (i.e., pollution control devices) in response to environmental regulations, such as the CAAA. It can represent limits on sulfur dioxide, nitrogen oxide, mercury, and carbon dioxide emissions.

Technology choices in the ECP include all of the fuel types used by suppliers—coal, natural gas, petroleum, uranium, and renewable. The 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 (e.g. steam, combined cycle, combustion turbine, hydraulic turbine, 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 (e.g., geothermal). Combined cycle and combustion turbine units primarily use natural gas and petroleum although some use waste heat. Hydraulic turbines include conventional and pumped storage. Advanced technologies include integrated gasification combined cycle, fuel cells, and advanced nuclear reactors. Renewable technologies include geothermal and biomass (wood). Intermittent renewable capacity (e.g., wind and solar) is also considered. Distributed generation options are represented as generic technologies serving peak and base loads.

In the ECP, planning decisions are represented for 13 electricity supply regions (see Chapter 1, Figure 3). Of the 13 regions, 8 correspond to North American Electric Reliability Council (NERC) Regions. These are the East Coast Area Reliability Coordination Agreement (ECAR), Electric Reliability Council of Texas (ERCOT), Mid-Atlantic Area Council (MAAC), Mid-America Interconnected Network (MAIN), Mid-Continent Area Power Pool (MAPP), Southeastern Electric Reliability Council (SERC), Florida Reliability Coordinating Council (FL) and Southwest Power Pool (SPP) Regions. The remaining two NERC Regions are divided into a total of five Subregions to isolate key states or areas. In the Northeast Power Coordinating Council (NPCC), the New England (NE) states constitute one region and New York (NY) represents another. The Western Electric Coordinating Council (WECC) is partitioned into three Subregions. The Rocky Mountain Power Area, and Arizona-New Mexico-Southern Nevada Power Area Subcouncils are combined into one region (RA). The Northwest Power Pool Area (NWP) and California (CA) form the other two electricity supply regions.

The general level of aggregation for the NEMS is Census Divisions, which are collections of states.[11] However, many utilities operate across state boundaries and the NERC Regions and Subregions provide a better representation of electricity operations. This geographic

[11] The demand, conversion, and supply modules of the 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 (e.g., energy prices and quantities) are specified for the nine Census Divisions. For additional information, see Energy Information Administration, *NEMS Integration Module Documentation Report*, DOE/EIA-M057(98) (Washington, DC, December 1998).

representation also facilitates collection of data and comparisons with industry projections, both of which are generally conducted at the utility- or NERC region-level.

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

The ECP, as a component of the EMM and the NEMS, is designed to provide forecasts for the *Annual Energy Outlook* and other analyses. For the electric power industry, the model projects planning decisions for each year in the midterm forecast horizon, currently defined as through 2025. It is designed to examine environmental policies such as the CAAA, limits on carbon dioxide emissions, and externality costs. It is also intended to examine the economic tradeoffs between the potential suppliers and the available generating technologies in response to different fuel price trajectories, environmental requirements, and macroeconomic conditions. The ECP can examine issues related to international and interregional trade, but it does not represent intra regional trade for the 13 electricity regions. The number and combinations of interregional and international trade opportunities in the ECP are restricted to those areas of the country where bulk power transfers currently exist. These transactions include the electricity supply regions in the West (regions 11, 12 and 13), in the Southeast (8 and 9), and between Canada and the U.S. (regions 1, 4, 5, 6, 7, 11, and 13). Similarly, new generating capacity can be built in selected regions with lower fuel costs to serve demands in other regions if the resulting savings in fuel costs is sufficient to offset the higher transmission costs. These "interregional" capacity additions are also limited to regions with existing relationships.

Relationship to Other Models

In addition to exogenous sources, the ECP requires input data from other modules of the NEMS and other submodules of the EMM (Figure 6). 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, repowering, and retirement decisions. For each capacity type that is a candidate for capacity expansion, external assumptions include overnight construction cost (i.e., without interest), and construction expenditure profile, operating life, maximum fuel shares, heat rate, and outage rates. Planned additions and retirements are assumed to occur as scheduled. Transmission and trade data inputs are also exogenously specified. 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 Integrating Module of the NEMS provides 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 Transmission and Distribution Module (NGTDM) 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. Cost and performance data for plant types fueled by renewable energy sources are obtained from the Renewable Fuels Module (RFM). For intermittent technologies, the RFM will

also provide the capacity credit, which represents the corresponding contribution to reliability requirements.

The Electricity Finance and Pricing (EFP) Submodule supplies the capital structure (debt/equity shares) and the cost of capital. The Electricity Load and Demand (ELD) Submodule furnishes the load curves for each year in the planning horizon.

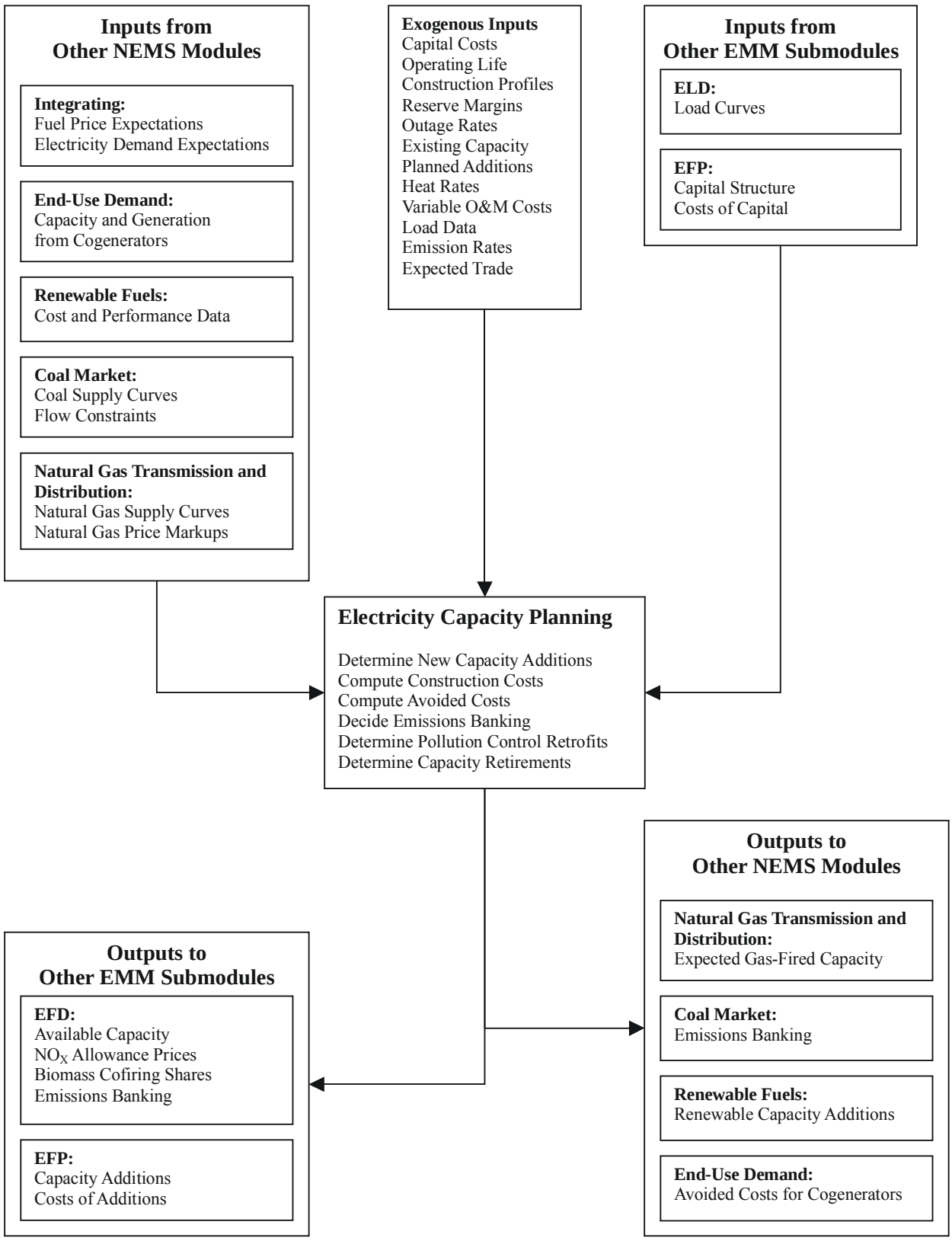
The EFP Submodule requires the capital expenditures for building new capacity and installing pollution control devices on existing units in order to calculate electricity prices. The Electricity Fuel Dispatching (EFD) Submodule uses capacity additions from the ECP to determine available capacity for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

The outputs of the ECP, which are determined by the selection of the least-cost options for meeting expected growth in demand, interact with other modules of the NEMS and Submodules of the EMM. The ECP provides its decision variables to other submodules of the EMM (Figure 6). Capacity additions for gas-fired generating capacity are provided to the NGTDM, which are used for planning decisions in this module. The RFM also receives capacity additions of renewable technologies. In particular, this is required for technologies with resource constraints or limited sites.

The interaction between the ECP and the Coal Market Module (CMM) is particularly important because the electricity and coal markets are closely related. Electricity production accounts for most of the coal consumption in the United States. Coal is the primary input fuel for electricity production and accounts for most of the emissions produced from power generation. Coal supplies vary considerably according to cost (production and transportation) and characteristics (Btu content, sulfur content, and mercury content). Therefore, the ECP includes a detailed representation of the coal supply curves contained in the CMM.[12]

[12] For more information on the description of coal production, transportation and environmental limits in the CMM, see Energy Information Administration, *Coal Market Module of the National Energy Modeling System, Model Documentation 2004*, DOE/EIA-M060(04) (Washington, DC, March 2004).

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



Model Overview and Rationale

Theoretical Approach

The ECP uses a linear programming (LP) formulation to determine planning decisions for the electric power industry. It has a three-period planning horizon to examine costs over a 20-year period as the final period of the planning horizon actually considers the accumulated costs for the final 18 years of the cost recovery period. The model uses multi-year optimization as it solves all the years simultaneously.

The ECP contains a representation of planning and dispatching in order to examine the tradeoff between capital and operating costs. It simulates 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 over the planning horizon. The ECP explicitly incorporates emissions restrictions imposed by the Clean Air Act Amendments (CAAA) and the Clean Air Interstate Rule (CAIR). It also provides the flexibility to examine potential regulations such as emissions taxes and carbon stabilization. The Clean Air Mercury Rule (CAMR) is not included in the AEO2010 projections since these regulations were vacated by court decisions. Some States have plans to implement mercury standards that are generally based on best available control technology and these regulations are represented.

Emissions banking also needs to be evaluated in a multi-year framework. Depending on the value of allowances, it may be advantageous to reduce emissions beyond required levels in an earlier year in order to under-comply in a later year. In the ECP, the value of an allowance is assumed to be the market-clearing price, which is based on the revenue requirements for the capital and operating expenses associated with compliance.[13] Based on the sulfur dioxide (SO_2) allowances allocated according to the CAAA, some utilities may have relatively low compliance costs for Phase 1 but incur much higher costs during Phase 2 since the restrictions are much tighter. Banking would lower the overall cost of compliance if the discounted, present value of the compliance costs in a given year is less than the corresponding cost in a later year.

To describe the demands for electric power, the ECP uses the projected load duration curves provided by the ELD. A typical load duration curve arranges hourly loads in descending order, but does not identify power requirements chronologically. The load requirements are categorized 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 the ECP to better represent time-dependent variations in both the demand for and supply of electricity.

In the 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” since they can usually can be operated at any time as long as they are not out-of-service due to planned or forced outages. Some renewable generating capacity, such

[13] The value of allowances could be affected by several issues, including cost recovery schedules for compliance costs (i.e., capitalized or expensed) and tax treatment (both federal and state). These regulatory decisions have not been determined yet.

as geothermal and biomass, are similar to fossil-fired and nuclear plants in that they 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 since they can only be operated when the resource occurs (unless accompanied by some storage capability). A demand storage technology can be used to decrease demand in the peak slice, displacing high cost generation, but must then be operated in other time slices to replace the shifted load.

In the ECP, a market-sharing algorithm adjusts the solution from the LP model to allow penetration of "competitive" but not "least-cost" alternatives.[14] 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 typically probabilistic and 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 since some quantity of the selected activity will be more expensive than some quantity of the option(s) 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[15]

It is assumed that capacity additions that are already under construction will be completed as reported.[16] Scheduled retirements of existing units are also assumed to occur. However, a large number of fossil-fired steam generating units are approaching the end of their normal operating lives, but utilities have not indicated any plans to retire them. The ECP evaluates whether it is more effective to continue operating those units or to replace them with new capacity. Thus, the 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. It is assumed that a new project is completed once it is initiated. Contributions from cogenerators are determined by the end-use demand modules.

The capacity additions determined by the ECP must be sufficient to satisfy minimum reliability requirements in each of the electricity supply regions. In a region with traditional cost-of-service regulation, it is assumed that the sum of existing capacity (net of retirements) and planned capacity additions, and unplanned additions must be greater than or equal to the expected peak demand by a pre-specified reserve margin. These reserve margins are derived using ten-year projections from the NERC for generating capability and peak demands.[17] However, some States are in various stages of deregulating the electric power industry. In these areas, it is assumed that the optimal reserve margin is represented by the level of capacity that balances the marginal cost of supply and the marginal cost that consumers are willing to pay for capacity (represented by

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

[15] For more detailed information see Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010 (AEO2010)*, DOE/EIA-0554(2010) (Washington, DC, April 2010).

[16] Planned capacity additions for electric utilities are reported on Form EIA-860A, "Annual Electric Generator Report–Utility." Scheduled additions for nonutilities are collected on Form EIA-860B, "Annual Electric Generator Report--Nonutility."

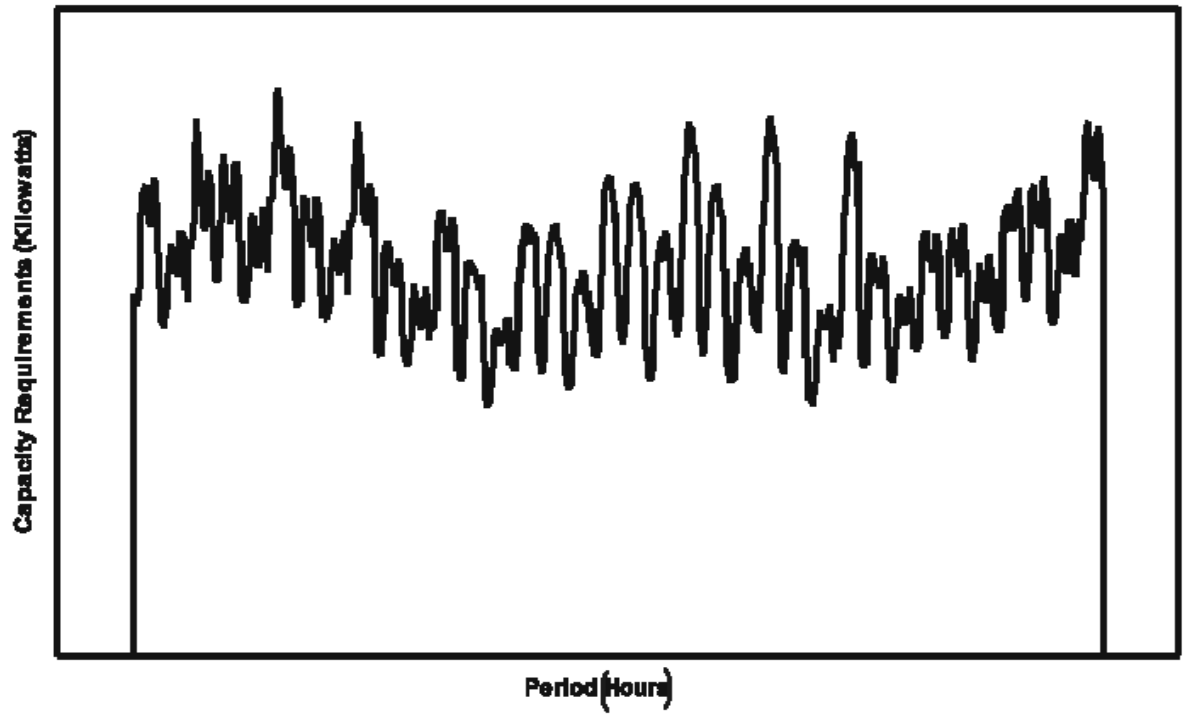
[17] These projections are contained in North American Electric Reliability, Electricity Supply & Demand 1992-2004 (Princeton, NJ, September 2004).

the cost of unserved energy). 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 her region is counted towards the reserve margin in the destination region.

The ECP determines planning strategies that are to be implemented to meet electricity demands and environmental requirements in "future" years; therefore, it is necessary to have information about future demands and fuel prices. "Perfect" foresight is used for future demands and prices.[18] Interest rates and inflation rates tend to remain fairly stable over time so the ECP assumes these will remain constant at current levels (i.e., the latest available rates, which correspond to the results from the previous forecast year). Similarly, the capital structure for financing new investments is assumed 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, the corresponding demands are mapped into the 13 electricity supply regions using constant shares derived from historical data. Demand for electric power fluctuates considerably over time (Figure 7). Chronological variations in the load are captured using a historical distribution of hourly load data from the North American Electric Reliability Council (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 on percent of demand), intermediate (next thirty-three percent of demands), and base (lowest sixty-six percent of demands). Therefore, there are a total of nine seasonal/load segments (Table 1).

Figure 7. Typical Annual Load Curve



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

Table 1. 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
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 are 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 determined for each of the 13 Electricity Supply Regions represented in the EMM. Each of the 13 regions is treated as a single "firm" as intra regional electricity trade is not explicitly represented. Within each region, the available 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 between the electricity supply regions are represented with the limits on power flows based on region to region transmission constraints.[19]

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

In the ECP, available supply options include fossil-fired, nuclear, and renewable plants (Table 2). Both conventional and advanced technologies are represented. Fossil-fired capacity consumes coal, oil, and natural gas. Renewable technologies include hydroelectric, biomass, geothermal, municipal solid waste, wind, and solar. A demand storage technology can also be included to model load shifting.

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 utilize capacity types with lower emission rates more intensively. Allowance trading is represented in the ECP by imposing a national-level limit on emissions that corresponds to the sum of the allowances allocated to individual generators. In effect, this simulates an allowance market in which producers with comparatively low costs of reducing emissions can overcomply and sell their excess allowances to suppliers with uneconomic compliance costs.

[19] Interregional transmission constraints are derived from Department of Energy, Form OE-411, "Coordinated Bulk Power Supply Program Report."

In addition to federal emissions requirements, it is also assumed that emissions from generating units satisfy state regulations. The total capacity for each technology option is determined from unit-level data and the applicable federal and state standards are identified for each unit prior to aggregation (Table 2). Compliance options are limited to those that violate none of the standards. As a result, an existing coal-fired unit without a scrubber may be limited to the types of coal that can be consumed (e.g., low-sulfur instead of medium- or high-sulfur) by one or more of the standards.

Existing coal capacity is represented by 32 categories that are defined by the types (if any) of particulate, sulfur dioxide, nitrogen oxide, and mercury control devices. These plant types are typically classified as unscrubbed or scrubbed, depending on whether or not they have Flue Gas Desulfurization (FGD) equipment. A given capacity type can include several different configurations since pollutants such as nitrogen oxide can be controlled using multiple devices such as low-NOX burners, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR). Each configuration is characterized by a removal rate for each of these emissions. A given coal capacity type can be converted to another configuration or category by retrofitting pollution control devices in order to comply with specified emissions limits.

Uncertainty about investment costs for new technologies is captured in the ECP using technological optimism and learning factors. These factors are calculated for each of the major design components of a plant type design (Table 3). For modeling purposes, components are identified only if the component is shared between multiple plant types, so that the ECP can reflect the learning that occurs across technologies. The cost adjustment factors are based on the cumulative capacity of a given component. This capacity is calculated by summing the contribution of the component to the capacity of each plant type that contains it (Table 4). It is assumed that for all combined-cycle technologies, the turbine component contributes two-thirds of the capacity and the steam unit one third. All non-capacity components contribute 100% toward component learning. Table 4 only shows components that contribute to multiple plant types, all other components map 100% to their particular technology.

Table 2. Capacity Types Represented in the Electricity Capacity Planning Submodule

Category
Existing Coal Steam
New Scrubbed Coal
Advanced Coal
Advanced Coal with Sequestration
Gas/Oil Steam Turbine
Existing Combustion Turbine
New Conventional Combustion Turbine
New Advanced Combustion Turbine
Existing Gas/Oil Combined Cycle
New Conventional Gas/Oil Combined Cycle
New Advanced Gas/Oil Combined Cycle
New Advanced Combined Cycle with Sequestration
Fuel Cells
Conventional Nuclear
Advanced Nuclear
Biomass (Wood)
Municipal Solid Waste
Geothermal
Hydroelectric
Pumped Storage
Demand Storage
Wind
Solar Thermal
Solar Photovoltaic
Distributed Generation - Base load
Distributed Generation - Peak load

Table 3. Design Components Represented in the Electricity Capacity Planning Submodule

Category
Pulverized Coal
Combustion Turbine - conventional
Combustion Turbine - advanced
Heat Recovery Steam Generator (HRSG)
Gasifier
Carbon Capture/Sequestration
Balance of Plant - Integrated Coal Gasification Combined Cycle (IGCC)
Balance of Plant - Turbine
Balance of Plant - Combined Cycle (CC)
Fuel Cell
Advanced Nuclear
Fuel prep - Biomass IGCC
Distributed Generation - Base
Distributed Generation - Peak
Geothermal
Municipal Solid Waste
Wind
Solar Thermal
Solar PV

Table 4. Component Capacity Weights for New Technologies

Technology	Combustion Turbine - conv.	Combustion Turbine- adv.	HRSG	Gasifier	Carbon Capture/ Sequest-ration	Balance of Plant - IGCC	Balance of Plant - Turbine	Balance of Plant - CC	Fuel prep Biomass IGCC
IGCC	0%	67%	33%	100%	0%	100%	0%	0%	0%
IGCC with carbon sequestration	0%	67%	33%	100%	100%	100%	0%	0%	0%
Conv Gas/Oil Comb Cycle	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cycle	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon seq.	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turb	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turb	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	0%	67%	33%	100%	0%	100%	0%	0%	100%

Model Structure

Introduction

The ECP is executed once each forecast year to determine planning decisions that must be completed within the planning horizon. The ECP uses a linear programming (LP) formulation to compete options for meeting future demands for electricity and complying with environmental regulations. It 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/distributions losses) are met, minimum reliability requirements are satisfied, and emissions limits are not exceeded.

The ECP prepares the input data, solves the LP model, and provides the required outputs to the other submodules of the EMM and modules of the NEMS. The initial matrix and objective function is 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 forecast horizon.

A system of equations has been incorporated in the ECP to simulate the production and transportation of coal. This formulation, which is based on the corresponding representation in the CMM, is included so that the ECP determines capacity planning, operating, and emissions control decisions using a similar distribution of the availability, costs (production, transportation, and emissions control), BTU contents (bituminous, subbituminous, and lignite), and emissions rates (sulfur, nitrogen oxide, mercury, and carbon dioxide) 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. The model uses on the Optimization and Modeling (OML) software, a proprietary mathematical programming package, to create and store coefficients in a database, solve the problem, and retrieve the solution. The OML subroutines are not documented in this report.[20] Capacity planning under competition, the Technology Penetration component, and the methodology for determining nuclear retirement decisions are described in the subsequent sections.

Key Computations and Equations

In the ECP, decision variables include building new generating capacity (conventional and advanced, renewable and nonrenewable technologies), trading firm power (interregional and international), installing pollution control devices at existing units, and banking emissions allowances (i.e., over complying in a particular year and saving the allowances for future use). 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.

[20] For more information, see Ketron Management Science, *Optimization and Modeling Library (Draft)*, (Arlington, VA, November 1992).

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 (e.g., 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. A baseload generating plant type is used in all of the load categories, whereas a peaking plant type is allocated to the first few segments (see Figure 8). A technology may be limited to a particular mode of operation (e.g., nuclear utilized in base load only), if appropriate. Dispatchable plant types receive full credit towards reliability requirements because they can be used during peak loads as long as they are not out-of-service. Contributions from intermittent technologies are limited to the appropriate load segments, depending on the availability of the resource (e.g., wind or sun). Intermittent technologies receive a partial capacity credit depending on their capability to provide electricity when the peak load occurs.

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 planning horizon, so the ECP evaluates each option on the basis of a life-cycle cost. For instance, capital costs (e.g., 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 (e.g., depreciation, taxes) over the predefined period. Similarly, operating costs are determined for all years in order to consider factors such as escalating fuel costs. For each operating decision variable in the first 5 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 the remaining years.

The structure of the ECP is described below.

Dimensions

a = Activated Carbon Option

b = Canadian Import Project

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/Storage Technology

j = All Years from Year 1 to Year 3

k = Capacity Type Other Than Capacity Type c

l = Vertical Load Steps Which Define Total Electricity Load

m = Mode of Operation (e.g., “Base,” “Intermediate,” “Peak”)

n = Renewable Capacity Type

o = Sulfur Dioxide Region (CAIR)

p = Previous Year In Planning Horizon

q = Avoided T&D cost supply step for Distributed Generation

r = Electricity Supply Region

s = Season

t = Distributed generation Technology Type (Base, Peak)

u = Unit Retrofitted with Pollution Control Devices

v = NOX Containment Area

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 = Coal-Fired Configuration Without Scrubbers

I = Coal-Fired Configuration 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/Biomass Demand Regions

O = Coal Units

P = Sulfur Dioxide Region (Non-CAIR)

R = Fuel Region

S = Fuel Season (Peak/Offpeak)

T = Fuel Transportation Step

U = Nuclear Units

Decision Variables

BCF_{yNA} = Retrofit Coal-Fired Capacity for Biomass Cofiring by Category A in Coal Region N in Year y (Gigawatts)

BCH_{yhb} = Build Canadian Hydro Capacity from Canadian Import Project b in International Region h in Year y (Gigawatts)

BLC_{yrRcE} = 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_{yrRcE} = Build New Non-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)

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

BNK_{yw} = Bank Allowances for SO_2 From Year y to the Next Year w (Thousands of Tons)

BNK_{py} = Allowances Banked for SO_2 In Previous Year p to be Used or Banked In Year y (Thousands of Tons)

$BNKHG_{yw}$ = Bank Allowances for Mercury From Year y to the Next Year w (Tons)

$BNKHG_{py}$ = Allowances Banked for Mercury In Previous Year p to be Used or Banked In Year y (Tons)

BRI_{yenrE} = Build Renewable Capacity Type n in EMM Region e for EMM Region r in Year y at Short-Term Supply Step E (Gigawatts)

$CARE_{y}$ = Total Carbon Emissions in Year y (Million Metric Tons)

$CARO_y$ = Non-fossil (Renewable) Carbon Emissions in Year y (Million Metric Tons)

DGN_{yrqt} = Build/Utilize Distributed Generation Type t and avoided cost supply step q Beginning Operation in Year y in EMM Region r (Gigawatts)

ECF_{yNA} = Existing Coal-Fired Capacity Retrofitted for Biomass Cofiring by Category A in Coal Region N in Year y (Gigawatts)

ECH_{yhb} = Existing Canadian Hydro Capacity from Canadian Import Project b in International Region h in Year y (Gigawatts)

EXC_{yrRO} = Existing Coal-Fired Units O Operated as Current Configuration in Year y in EMM Region r and Fuel Region R (Gigawatts)

EXD_{yrRD} = Existing Non-Coal Dispatchable Capacity Type D (Announced Retirements) in Year y in EMM Region r and Fuel Region R (Gigawatts)

$EXDM_{yrRD}$ = Existing Must-Run, Non-Coal Dispatchable Capacity Type D in Year y in EMM Region r and Fuel Region R (Gigawatts)

$EXDR_{yrRDx}$ = Existing Non-Coal Dispatchable Capacity Type D (Retirement Candidate) in Retirement Group x in Year y in EMM Region r and Fuel Region R (Gigawatts)

EXH_{yr} = Existing Hydro Energy in Year y in EMM Region r (Gigawatthours)

EXI_{yri} = Existing Intermittent Capacity Type i in Year y in EMM Region r (Gigawatts)

EXR_{yrn} = Existing Renewable Capacity Type n in Year y in EMM Region r (Gigawatts)

$EXST_{yr}$ = Existing Demand Storage Capacity in Year y in EMM Region r (Gigawatts)

GEL_{yr} = Total Generation for EMM Region r in Year y (Billion Kilowatthours)

INT_{yriE} = Build/Utilize Intermittent Renewable Type I Beginning Operation in Year y in EMM Region r at Short Term Supply Step E (Gigawatts)

$MERCE_{yoC}$ = Mercury Emissions from Coal Capacity Type C in SO_2 Region o in Year y (Thousandths of Tons)$_{DD}$

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

$NOXE_{yvC}$ = NO_x Emissions from Coal Capacity Type C in NO_x Containment Region v in Year y (Thousand Tons)

$NOXE_{yvD}$ = NO_x Emissions from Non-Coal Capacity Type D in NO_x Containment Region v in Year y (Thousand Tons)

$NOXX_{yvC}$ = NO_x Emissions Reductions from Retrofitting Uncontrolled Coal Capacity Type C in NO_x Containment Region v in Year y (Thousand Tons)

OCH_{yrh} = Utilize Available Canadian Hydro Capacity in Year y from International Region h in Region r (Gigawatts)

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

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

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

$OPD_{yrRDfms}$ = 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)

$OPDM_{yrRDms}$ = Utilize Must-Run 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)

OPH_{yrl} = Utilize Hydro Capacity in Vertical Load Step l in Year y in EMM Region r (Gigawatts)

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

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

PMC_{yrcr} = Planned Maintenance Scheduled for Capacity Type c in EMM Region r in Season s in Year y (Gigawatts)

PMM_{yrcr} = Planned Maintenance Scheduled for Must-Run Capacity Type c in EMM Region r in Season s in Year y (Gigawatts)

QBM_{yNd} = Quantity of Biomass Fuel Consumed for Supply Step d in Biomass Region N in Year y (Trillion Btu)

$QBMET_{yN}$ = Quantity of Biomass Fuel Consumed for Ethanol Production in Coal Region N in Year y (Trillion Btu)

$QBMIN_{yN}$ = Quantity of Biomass Fuel Consumed by the Industrial Sector in Coal Region N in Year y (Trillion Btu)

QCL_{yJM} = Quantity of Coal Produced from Supply Curve J and Supply Step M in Year y (Trillion Btu)

QNG_{yd} = Quantity of Natural Gas Consumed for Supply Step d in Year y (Trillion Btu)

QOL_{yd} = Quantity of Oil Consumed for Supply Step d in Year y (Trillion Btu)

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

$RPSR_{yr}$ = Regional RPS Generation in Region r in Year y (Billion Kilowatthours)

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

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

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

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

$SO2T_{yoP}$ = SO_2 Emissions Traded from SO_2 (CAIR) Region o to SO_2 (Non-CAIR) Region P in Year y (Thousand Tons)

$SO2T_{yPo}$ = SO_2 Emissions Traded from SO_2 (non-CAIR) Region P to SO_2 (CAIR) Region o in Year y (Thousand Tons)

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

TBM_{yrRABC} = Quantity of Biomass Transported to Capacity Type C and Cofiring Category A with Cofiring Level B in Fuel Region R and EMM Region r in Year y (Trillion Btu)

TCL_{yJRCa} = Quantity of Coal Transported from Supply Curve J to Fuel Region R Used in Capacity Type C with Activated Carbon Level a in Year y (Trillion Btu)

$TC2_{yJRC}$ = Quantity of Coal Transported at Additional Coal (Tier 2) Cost from Supply Curve J to Fuel Region R Used in Capacity Type C in Year y (Trillion Btu)

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

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

TOL_{yRST} = Quantity of Oil Transported to Fuel Region R For Transportation Step T in Fuel Season S in Year y (Trillion Btu)

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

$UNIT_{yOH}$ = Existing Coal-Fired Units O That Operate That Operate as Uncontrolled Configuration Type H in Year y (Gigawatts)

$UNIT_{yOI}$ = Existing Coal-Fired Units O That Operate That Operate as Controlled Configuration Type I in Year y (Gigawatts)

$UNTM_{yOH}$ = Existing Must-Run Coal-Fired Units O That Operate as Uncontrolled Configuration Type H in Year y (Gigawatts)

$UNTM_{yOI}$ = Existing Must-Run Coal-Fired Units O That Operate as Controlled Configuration Type I in Year y (Gigawatts)

The operate, or utilize variable for coal-fired units (OPC_{yrNCms}) represent the choices to consume coals from different supply curves. Some coal 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 alternate 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 units is represented for 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 the 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 describes units with announced retirement dates. The second variable represents capacity that can be retired by the 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 are 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, it is assumed that these plants are characterized by a minimum generation requirement and they are not considered for retirement. For must-run coal 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 back-up technology. If additional capacity is need to meet reliability requirements and an intermittent technology without a full capacity credit (i.e., contribution to reserve margin 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 offsets the capital investment. The model could be modified to include intermittent technologies coupled with a backup power source by creating a composite capacity type that combined cost and operating characteristics of both plant types. This capacity type would receive a full capacity credit and would then be analogous to a dispatchable capacity type. However, this approach would reduce the flexibility of the model to choose the backup technology.

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 fifty and five

percent, respectively. Compared to central-station plants, distributed generation capacity typically has higher construction and operating costs, but may be economic 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.

Right-Hand Side Values for Constraints

$CCSL_{y}$ = Retrofit Limit for CCS Retrofits in Year y (Gigawatts)

$CHYL_{hb}$ = Limit for Accelerating Canadian Hydro Capacity for Project b in International Region h

COL_{yrc} = Available Coal Capacity Type c for Year y and EMM Region r (Gigawatts)

$CPLIM_{ycE}$ = Short Term Capacity Limit for Dispatchable Type c for Year y and Supply Step E (Gigawatts)

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

$CPLIM_{yrE}$ = Short Term Capacity Limit for Renewable Type r for Year y and Supply Step E (Gigawatts)

$DGNL_{yrg}$ = Amount of New Capacity that Can Be Met by Distributed Generation for Supply Step q in Year y and EMM Region r (Gigawatts)

ELC_{yrl} = Capacity Requirement In the Vertical Load Slice l In Year y and EMM Region r (Gigawatts)

EXP_{yrsl} = Electricity Export Limit in Season s and Load Slice l in Year y and EMM Region r (Gigawatts)

$FGDL_{y}$ = Retrofit Limit for Scrubber Retrofits in Year y (Gigawatts)

IMP_{yrsl} = Electricity Import Limit in Season s and Load Slice l in Year y and EMM Region r (Gigawatts)

$INTL_{ir}$ = Intermittent Build Limit for Intermittent Technology I and EMM Region r (Gigawatts)

$LMERC_{y}$ = Mercury Emission Limit for Year y (Million Tons)

$LCAR_{yQ}$ = Carbon Emission Limit for CO2 Containment Area Q and for Year y (Million Metric Tons)

$LNOX_{yv}$ = NOX Emission Limit for NOX Containment Area v and for Year y (Million Tons)

$LSO2_{yo}$ = Total SO_2 Limit for SO_2 Region o in Year y (Million Tons)

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

NUC_{yrc} = Available Nuclear Capacity Type c for Year y and EMM Region r (Gigawatts)

RGS_{yr} = Regional SO_2 Emissions Limits for Year y and EMM Region r (Million Tons)

RMQ_{yr} = Total Capacity Requirement Including a Reserve Margin In Year y and EMM Region r (Gigawatts)

$RNWL_{nr}$ = Renewable Build Limit for Renewable Capacity Type n and EMM Region r (Gigawatts)

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

Coefficients for Objective Function and Constraints

$CARC_{yJR}$ = Amount of Carbon Produced Per Unit of Coal from Supply Region J Transported to Fuel Region R in Year y (Thousand Metric Tons / Trllion Btu)

$CARD_{yf}$ = Amount of Carbon Produced Per Unit of Fuel f in Year y (Thousand Metric Tons / Trillion Btu)

$CARR_{c}$ = Carbon Removal Rate for Capacity Type c (Fraction)

$CAVD_{yrq}$ = Investment Cost for New T&D Equipment Avoided by DG for supply step q in EMM Region r.

$CBCF_{yA}$ = Investment Cost to Retrofit Cofiring Category A in Year y (Millions of Dollars / Gigawatt)

$CBCH_{yhb}$ = Investment Cost to Build Canadian Hydro Capacity from Canadian Project b in International Region h With Initial Online Year y (Millions of Dollars / Gigawatt)

$CBLC_{yrRcE}$ = 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)

$CBLD_{yrRcE}$ = Investment Cost to Build Non-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)

$CBTUB_{yr}$ = Fuel Requirement to Utilize Biomass Capacity in Year y in EMM Region r (Trillion Btu)

$CBTUC_{yrCms}$ = Fuel Requirement to Utilize Coal Capacity Type C in Mode m in Season s in Year y in EMM Region r (Trillion Btu)

$CBTUD_{yrDms}$ = Fuel Requirement to Utilize Non-Coal Capacity Type D in Mode m in Season s in Year y in EMM Region r (Trillion Btu)

$CBT1_{yJUH}$ = Allowable First-Tier Coal Transported from Supply Curve J used, per Unit of Capacity, by Unit U of Unscrubbed Configuration H in Year y (Trillion Btu per Gigawatt)

$CBT1_{yJUI}$ = Allowable First-Tier Coal Transported from Supply Curve J used, per Unit of Capacity, by Unit U of Scrubbed Configuration I in Year y (Trillion Btu per Gigawatt)

$CCAR_{y}$ = Carbon Allowance Price in Year y (Dollars per Metric Ton)

$CCSB_{y}$ = Bonus Allowances for Carbon Capture and Storage (CCS) in Year y (Scalar)

$CDGN_{yrt}$ = Investment and Operating Cost to Build/Operate Distributed Generating Technology t Starting Operation in Year y in Region r (Millions of Dollars)

$CDVL_{yOH}$ = Allowable Lignite Consumption per Unit of Capacity by Unit O Operated as Unscrubbed Configuration H in Year y (Trillion Btu per Gigawatt)

$CDVL_{yOI}$ = Allowable Lignite Consumption per Unit of Capacity by Unit O Operated as Scrubbed Configuration I in Year y (Trillion Btu per Gigawatt)

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

$CDVS_{yOI}$ = Allowable Subbituminous Coal Consumption per Unit of Capacity by Unit O Operated as Scrubbed Configuration I in Year y (Trillion Btu per Gigawatt)

$CFAC_{yrc}$ = Utilization Rate for Capacity Type c in Electricity Supply Region r in Year y (Fraction)

$CFBTU_{yNA}$ = Average Fuel Use, per Unit of Capacity, for Units of Cofiring Category A in Coal Region N in Year y (Trillion Btu per Gigawatt)

$CFLEV_{AB}$ = Cofiring Level for Cofiring Category A and Utilization Option B (Fraction)

$CFXD_{yrRD}$ = Fixed Operating Costs for Dispatchable Capacity Type D (With Announced Retirement Date) in Year y and Region r (Millions of Dollars / Gigawatt)

$CFXDM_{yrRD}$ = Fixed Operating Costs for Must-Run Dispatchable Capacity Type D (With Announced Retirement Date) in Year y and Region r (Millions of Dollars / Gigawatt)

$CFXDR_{yrRDx}$ = Fixed Operating Costs for Dispatchable Capacity Type D (Retirement Candidate) In Retirement Group x in Year y and Region r (Millions of Dollars / Gigawatt)

$CFXF_{yA}$ = Fixed Operating Costs for Cofiring Retrofit Category A in Year y (Millions of Dollars / Gigawatt)

$CFXS_{yOI}$ = Fixed (Including Retrofit) Costs to Operate Coal Unit O as Controlled (e.g., Scrubbed) Configuration Type I in Planning Year y (Gigawatts)

$CFXSM_{yOI}$ = Fixed (Including Retrofit) Costs to Operate Must-Run Coal Unit O as Controlled (e.g., Scrubbed) Configuration Type I in Planning Year y (Gigawatts)

$CFXU_{yOH}$ = Fixed (Including Retrofit) Costs to Operate Coal Unit O as Uncontrolled (e.g., Unscrubbed) Configuration Type H in Planning Year y (Gigawatts)

$CFXUM_{yOH}$ = Fixed (Including Retrofit) Costs to Operate Must-Run Coal Unit O as Uncontrolled (e.g., Unscrubbed) Configuration Type H in Planning Year y (Gigawatts)

$CINT_{yriE}$ = 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)

$CONT_{yJOH}$ = Coal Consumed per Unit of Capacity by Unit O Operated as Unscrubbed Configuration H Required to be Satisfied by Coal Supply Curve J in Year y (Trillion Btu per Gigawatt)

$CONT_{yJOI}$ = Coal Consumed per Unit of Capacity by Unit O Operated as Scrubbed Configuration I Required to be Satisfied by Coal Supply Curve J in Year y (Trillion Btu per Gigawatt)

$COPB_{yrN}$ = Variable Operating Cost to Operate Biomass Renewable Capacity Type n for Year y and Coal Demand Region N for EMM Region r (Million Dollars / Gigawatt)

$COPC_{yrRCms}$ = Nonfuel Operating Costs to Utilize Non-Must Run Coal Capacity Type C in Mode m in Season s in EMM Region r and Fuel Region R in Year y (Million Dollars per Gigawatt)

$COPCM_{yrRCms}$= Nonfuel Operating Costs to Utilize Must-Run Coal Capacity Type C in Mode m in Season s in EMM Region r and Fuel Region R in Year y (Million Dollars per Gigawatt)

$COPD_{yrRDfms}$= Variable Operating Cost to Operate Non-Coal Dispatchable Capacity Type D Using Fuel f In Mode m in Season s for Year y and EMM Region r and Fuel Region R (Million Dollars / Gigawatt)

$COPDM_{yrRDfms}$= Variable Operating Cost to Operate Non-Coal Must-Run Dispatchable Capacity Type D Using Fuel f In Mode m in Season s for Year y and EMM Region r and Fuel Region R (Million Dollars / Gigawatt)

$COPH_{yrl}$ = Variable Operating Cost to Operate Hydro Capacity In Load l for Year y and EMM Region r (Million Dollars / Gigawatt)

$COPR_{yrn}$ = Variable Operating Cost to Operate Non-Biomass Renewable Capacity Type n for Year y and EMM Region r (Million Dollars / Gigawatt)

$CPMR_{rc}$ = Amount of Time Required for Planned Maintenance for Capacity Type c in EMM Region r (Thousands of Hours)

$CRET_{yOHI}$ = Investment (Retrofit) Cost to Convert Coal Unit O From Uncontrolled Configuration H to Controlled Configuration I in year y (Millions of Dollars / Gigawatt)

$CRNW_{yrnE}$ = 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)

$CTRB_{yABNC}$ = Transportation (Incremental) Cost to Cofire with Biomass for Cofiring Category A and Cofiring Level B in Coal Capacity Type C in Coal Region N in Year y (Million Dollars per Trillion Btu)

$CTRE_{yegsl}$ = Cost of Transferring Electricity from EMM Region e to EMM Region r in Season s and Load Slice l in Year y (Millions of Dollars / Gigawatt)

$CTRN_{yRST}$ = Transportation Cost to Use Natural Gas in Fuel Season S in Fuel Region R at Transportation Step T in Year y (Million Dollars per Trillion Btu)

$CTRO_{yRST}$ = Transportation Cost to Use Oil in Fuel Season S in Fuel Region R at Transportation Step T in Year y (Million Dollars per Trillion Btu)

$CTR1_{yJNCa}$ = Tier 1 Transportation and Activated Carbon Cost to Use Coal from Supply Curve J to Coal Demand Region N Used in Capacity Type C with Activated Carbon Level a in Year y (Million Dollars per Trillion Btu)

$CTR2_{yJNC}$ = Incremental Transportation Cost for Tier 2 Coal from Supply Curve J to Coal Demand Region N Used in Capacity Type C in Year y (Million Dollars per Trillion Btu)

ELA_{yrCml} = Derating Factor (Adjustment for Forced Outage, Planned Maintenance, and Load Following Rates) for Coal Capacity Type C Allocated to Meet Capacity Requirements In Load Step l In Year y, EMM Region r By Capacity Type c In Mode m (Fraction)

ELA_{yrDml} = 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 Load Step l In Year y, EMM Region r By Capacity Type c In Mode m (Fraction)

ELB_{yr} = Derating Factor (Adjustment for Forced Outage, Planned Maintenance, Load Following Rates and Availability of Resource) for Biomass Capacity Allocated to Meet Capacity Requirements in Year y and EMM Region r (Fraction)

$ELCH_{yhb}$ = Derating Factor (Availability of Resource) for Canadian Project b in International Region h In Year y (Fraction)

ELD_{yrt} = Derating Factor corresponding to mode of operation (Base, Peak) for Distributed Generation technology type t in EMM Region r in Year y (Fraction)

ELI_{yril} = Derating Factor (Availability of Resource) for Intermittents in Load Step l In Region r By Intermittent Technology Type I Beginning Operation in Year y (Fraction)

ELR_{yrn} = 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 Capacity Type n (Fraction)

$HRTE_{yrc}$ = Heat Rate for Capacity Type c in Electricity Supply Region r in Year y (Btu / Kilowatthour)

$ISHR_i$ = Amount of Generation for Intermittent Capacity Type i That Is Counted Toward Minimum Generation Requirement (Fraction)

$LHRS_l$ = Hours in Load Segment l (Thousands of Hours)

$MERC_{yJNCa}$ = Amount of Mercury in Coal from Supply Curve J Used in Coal Capacity in Coal Region N in Coal Capacity Type C With Activated Carbon Option a in year y (Tons / Trillion Btu)

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

NOX_{vCk} = Investment Cost to Convert Uncontrolled Coal Capacity Type C to Controlled Plant Group v with NOX Control Technology k

$NOXC_{yvNCms}$ = Amount of NOX Produced per Unit of Electricity Generated in Year y for NOX Containment Area v by Coal Capacity Type C in Coal Region N in Mode m and in Season s (Millions of Tons / Gigawatt)

$NOXD_{yvDfms}$ = Amount of NOX Produced per Unit of Electricity Generated in Year y for NOX Containment Area v by Non-Coal Dispatchable Capacity Type D with Fuel f in Mode m and in Season s (Millions of Tons / Gigawatt)

$NOXR_{yvHI}$ = Reduction in Amount of NOX Produced Due to Converting Uncontrolled Existing Coal Configuration H to Controlled Configuration I k by Retrofitting NOX Controls in NOX Containment Area v in Year y (Millions of Tons / Gigawatt)

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

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

PNG_{yd} = Production Cost for Natural Gas Consumed to Generate Electricity on Supply Step d in Year y (Dollars per Million Btu)

POL_{yd} = Production Cost for Oil Consumed to Generate Electricity on Supply Step d in Year y (Dollars per Million Btu)

RMC_{yrc} = Contribution Made to Satisfying the Reserve Margin Made By Dispatchable Capacity Build Type c Beginning Operation In Year y for Region r (Fraction)

RMD_{yrt} = Contribution Made to Reserve Margin Made by Distributed Generation Type t in Year y for Region r (Fraction)

RMI_{yri} = Contribution Made to Satisfying the Reserve Margin Made By Intermittent Technology I Beginning Operation In Year y for Region r (Fraction, 0.0 = Resource Never Available at Peak, 1.0 = Resource is Always Available at Peak)

$RMIN_{y}$ = Amount of Total Generation or Sales That Must Be Provided by Renewable Technologies (Fraction)

RMR_{yrn} = Contribution Made to Satisfying the Reserve Margin Made By Renewable Capacity Build Type n Beginning Operation In Year y for Region r (Fraction)

$RSHR_{n}$ = Amount of Generation for Renewable Capacity Type n That Is Counted Toward Minimum Generation Requirement (Fraction)

$RPSP_{y}$ = Renewable Portfolio Standard (RPS) Requirement in Year y (Fraction)

$SHOURS_{s}$ = Hours in Season s (Thousands of Hours)

SNG_{yRDf} = Fuel Share for Natural Gas in Noncoal Dispatchable Type D using Fuel Type f in Fuel Region R in Year y (Fraction)

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

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

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

$SO2R_{yo}$ = Allowances Required per Ton of SO_2 Emitted in SO2 (CAIR) Region o in Year y (Scalar)

$SO2R_{yP}$ = Allowances Required per Ton of SO_2 Emitted in SO2 (non-CAIR) Region P in Year y (Scalar)

$STFAC_{i}$ = Generation Replacement Factor for Storage Technology type i (Fraction)

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

$TLOSS_{yer}$ = 1 - Interregional Transmission Loss Factor from region e to region r in Year y (Fraction)

Objective Function

The objective function of the planning component is to minimize the total, discounted present value of the costs of meeting demand and complying with environmental regulations over 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 forecast 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:

- operation (fixed) plus retrofit (if any) costs of existing uncontrolled coal units ($CFXU_{yOH}$ • $UNIT_{yOH}$ and $CFXUM_{yOH}$ • $UNTM_{yOH}$) 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, oil, and biomass (PCL_{yJM} • QCL_{yJM}, PNG_{yd} • QNG_{yd}, POL_{yd} • QOL_{yd}, and PBM_{yNd} • QBM_{yNd})

- transportation and activated carbon costs for delivering coal for Tier-1 ($CTR1_{yJRCa}$ • TCL_{yJRCa}) and Tier-2 ($CTR2_{yJRC}$ • $TC2_{yJRC}$) 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_{yrRABC})

- operation (variable) costs for coal capacity types ($COPC_{yrNCms}$ • OPC_{yrNCms} 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 of new intermittent capacity types for another region ($CBII_{yeirE}$ • BII_{yeirE}).

- construction of new renewable capacity types ($CRNW_{yrnE}$ • RNW_{yrnE}).

- construction of new renewable capacity types for another region ($CBRI_{yenrE}$ • BRI_{yenrE}).

- construction of Canadian Hydro capacity ($CBCH_{yhp}$ • BCH_{yhp})

- 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 ($CRET_{yOHI}$ • $UNIT_{yOH}$)
- transfer of electricity between regions ($CTRE_{yegsl}$ • TRE_{yegsl})
- cost of purchasing carbon allowances ($CCAR_y$ • $CARE_y$)

The objective function is expressed as follows:

$$
\begin{aligned}
\text{MIN} \; & \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 UNTM_{yOH} + \sum_{y}\sum_{o}\sum_{I} CFXSM_{yOI} \cdot UNTM_{yOI} \\
& + \sum_{y}\sum_{r}\sum_{D}\sum_{x} CFXD_{yrDdx} \cdot EXD_{yrDx} + \sum_{y}\sum_{r}\sum_{D}\sum_{x} CFXDM_{yrDdx} \cdot EXDM_{yrDx} \\
& + \sum_{y}\sum_{r}\sum_{D}\sum_{x} CFXDR_{yrDdx} \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_{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_{D}\sum_{S}\sum_{T} CTRN_{yDST} \cdot TRN_{yDST} + \sum_{y}\sum_{D}\sum_{S}\sum_{T} CTRO_{yDST} \cdot TRO_{yDST} + \sum_{y}\sum_{r}\sum_{R}\sum_{A}\sum_{B}\sum_{C} CTRB_{yAB} \cdot TBM_{yrRABC} \\
& + \sum_{y}\sum_{r}\sum_{N}\sum_{C}\sum_{m}\sum_{s} COPC_{yrNCms} \cdot OPC_{yrNCms} + \sum_{y}\sum_{r}\sum_{N}\sum_{C}\sum_{m}\sum_{s} COPCM_{yrNCms} \cdot OPCM_{yrNCms} \\
& + \sum_{y}\sum_{r}\sum_{D}\sum_{m}\sum_{s}\sum_{f} COPD_{yrDfms} \cdot OPD_{yDfms} + \sum_{y}\sum_{r}\sum_{D}\sum_{m}\sum_{s}\sum_{f} COPDM_{yrDfms} \cdot OPDM_{yDfms} \\
& + \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_{e}\sum_{i}\sum_{r}\sum_{E} CBII_{yeirE} \cdot BII_{yeirE} \\
& + \sum_{y}\sum_{r}\sum_{n}\sum_{E} CRNW_{yrnE} \cdot RNW_{yrnE} + \sum_{y}\sum_{e}\sum_{n}\sum_{r}\sum_{E} CBRI_{yenrE} \cdot BRI_{yenrE} + \sum_{y}\sum_{h}\sum_{p} CBCH_{yhp} \cdot BCH_{yhp} \\
& + \sum_{y}\sum_{r}\sum_{t}\sum_{a} (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_{e}\sum_{g}\sum_{s}\sum_{l} CTRE_{yegsl} \cdot TRE_{yegsl} + \sum_{y} CCAR_y \cdot CARE_y
\end{aligned}
\tag{3-1}
$$

Description of Constraints

Coal Submatrix. The 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 the Coal Market Module (CMM). The ECP determines decisions for operation, capacity expansion, and emissions control in coal-fired capacity based on this representation. Since coal plants can also be modified to cofire with biomass fuels, decisions to retrofit existing capacity to allow cofiring are also included in this structure.

The ECP utilizes the same two-tier pricing system for transportation costs that is incorporated in the 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. 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 plants in a particular Electricity Region may be able to obtain fuel supplies from more than one Coal Demand Region.

***Production Balance Rows*.** These rows insure 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) $$\sum_{M} \mathbf{PCL}_{\mathbf{yJM}} \leq \mathbf{MAX}_{\mathbf{yJ}}$$

for every coal supply curve J in year y.

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

(3-3) $$\sum_{R} \sum_{C} \sum_{a} \mathbf{TCL}_{\mathbf{yJRCa}} + \mathbf{OTH}_{\mathbf{yJ}} - \sum_{M} \mathbf{PCL}_{\mathbf{yJM}} \leq \mathbf{0}$$

for every coal supply curve J in year y.

***Material Balance Rows for Demand*.** These constraints insure 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. For each coal capacity type C, the fuel requirement is the product of the capacity allocated to produce electricity (OPC_{yrNCms}) and the fuel use per unit of capacity ($CBTU_{yrNCms}$). Similarly, fuel use by must-run plants is the product of the corresponding operate variable (OPC_{yrNCms}) and fuel use rate ($CBTU_{yrNCms}$). Coal use is also reduced by biomass fuel used for cofiring (TBM_{yrRABC}). The material balance rows insure that the coal transported (TCL_{yJRCa}) is sufficient to satisfy the demand by each coal-fired capacity type, as follows:

(3-4) $$\sum_{r}\sum_{m}\sum_{s} \mathbf{CBTUC}_{\mathbf{yrRCms}} \cdot \mathbf{OPC}_{\mathbf{yrRCms}} + \sum_{r}\sum_{m}\sum_{s} \mathbf{CBTUC}_{\mathbf{yrRCms}} \cdot \mathbf{OPCM}_{\mathbf{yrRCms}} + - \sum_{J}\sum_{a} \mathbf{TCL}_{\mathbf{yJRCa}} - \sum_{r}\sum_{A}\sum_{B} \mathbf{TBM}_{\mathbf{yrRABC}} \leq \mathbf{0}$$

for every coal plant type C in fuel region R in year y.

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:

(3-5) $$\sum_{R}\sum_{F}\sum_{a} \mathbf{TCL}_{\mathbf{yJRFa}} \geq \mathbf{CUNS}_{\mathbf{yJN}}$$

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

There are some coal regions N that contain multiple fuel regions R. Therefore, the contract requirement for unscrubbed plants ($CUNS_{yJN}$) transportation vectors (TCL_{yJRFa}) are summed over the specific fuel regions that correspond to a given coal region. That coefficient $CONT_{yJOH}$ represents the quantity, per gigawatt of capacity, of the total coal consumed by unscrubbed capacity type J that must be satisfied by coal from supply curve J in coal region N in year y.[21] The product of this coefficient and the capacity variable $UNIT_{yOH}$ provides the corresponding contract flows. Thus, the equation requires that the coal transported from the supply curve J in coal region N to unscrubbed coal plants F (TCL_{yJRFa}) must satisfy the contract amount.

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 the units O with scrubbed configurations I instead of unscrubbed configurations H.

Diversity Requirements. Some coal-fired 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 in unscrubbed plants, the diversity constraints are represented as follows:

$$\sum_{K}\sum_{a} TCL_{yKNFa} - \sum_{O}\sum_{H} CDVS_{yOH} \bullet UNIT_{yOH} \leq 0 \qquad (3\text{-}6)$$

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

The coefficient $CDVS_{yOH}$ represents the maximum quantity, per gigawatt of capacity, of the total coal consumed by coal units O of unscrubbed configuration H that can be satisfied by coal by subbituminous coal in year y.[22] 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 unscrubbed coal plants H in coal region N 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.

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. In order to deliver additional supplies, an incremental cost (second tier rates) is incurred. The constraints on first-tier rates are imposed as follows:

$$\sum_{a} TCL_{yJNFa} - TC2_{yJRF} - \sum_{O}\sum_{H} CBT1_{yJOH} \cdot UNIT_{yOH} \leq 0 \qquad (3\text{-}7)$$

for every supply curve J to unscrubbed capacity type F in fuel region R in year y.

[21] $CONT_{yJOH}$ is derived by multiplying the total fuel consumed at the unit during the previous year by the fraction of this demand that must be satisfied by the particular contract and then dividing by the total capacity.

[22] $CDVS_{yOH}$ 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 the subbituminous coal and then dividing by the total capacity. The subsequent coefficients for lignite and scrubbed capacity types are determined similarly.

The coefficient $CBT1_{yJOH}$ represents the maximum quantity, per gigawatt of capacity, of the total coal consumed by coal unit O of unscrubbed capacity configuration H that can be transported from supply curve J at the first-tier rates.[23] 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 (peak/offpeak).

Material Balance Rows for Demand. These constraints accumulate the fuel consumption required to generate electricity by non-coal, fossil 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 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 ($CBTD_{yrDms}$). Therefore, Equation (3-8) describes fuel consumption in noncoal fossil plants for non-must-run capacity.

$$\sum_{r}\sum_{m}\sum_{S} CBTUD_{yrDmS} \bullet OPD_{yrRDmS} - \sum_{f} TFL_{yRDSf} \le 0 \qquad (3\text{-}8)$$

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

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

$$\sum_{r}\sum_{m}\sum_{S} CBTUD_{yrDmS} \bullet OPDM_{yrRDmS} - \sum_{f} TFLM_{yRDSf} \le 0 \qquad (3\text{-}9)$$

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

Material Balance Rows for Transportation. These constraints insure 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. Since 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:

$$\sum_{D}\sum_{f} SNG_{yRDf} \bullet TFL_{yRDfS} + \sum_{D}\sum_{f} SNGM_{yRDf} \bullet TFLM_{yRDfS} - \sum_{T} TNG_{yRST} \le 0 \qquad (3\text{-}10)$$

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

[23] $CBT1_{yJOH}$ 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.

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

$$\sum_{D}\sum_{R}\sum_{S}\sum_{T} \Sigma NG_{yRDST} - \sum_{d} QNG_{yd} \leq 0 \quad (3\text{-}11)$$

for every year y.

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 peak/offpeak so there is only one fuel season S.

Material Balance Rows for Demand. These constraints determine the total fuel requirements for plant using oil. For oil fuel types f, the respective consumption totals for non-must-run and must-run capacity is specified as follows:

$$\sum_{r}\sum_{m}\sum_{S} \Sigma CBTUD_{yrDmS} \bullet OPD_{yrRDmS} - \sum_{f} TFL_{yRDSf} \leq 0 \quad (3\text{-}12)$$

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:

$$\sum_{r}\sum_{m}\sum_{S} \Sigma CBTUD_{yrDmS} \bullet OPDM_{yrRDmS} - \sum_{f} TFLM_{yRDSf} \leq 0 \quad (3\text{-}13)$$

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

Material Balance Rows for Transportation. These constraints insure that sufficient quantities of oil (TOL_{yRST})are delivered to each fuel region R in both the peak and off-peak periods S. The delivered fuel requirement (TOL_{yRST}) is the sum of the non-must-run and must-run capacity. Since 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:

$$\sum_{D}\sum_{f} \Sigma SOL_{yRDf} \bullet TFL_{yRDfS} + \sum_{D}\sum_{f} \Sigma SOLM_{yRDf} \bullet TFLM_{yRDfS} - \sum_{T} TOL_{yRST} \leq 0 \quad (3\text{-}14)$$

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

Material Balance Rows for Supply. These constraints insure that there are sufficient oil supplies are produced to satisfy the transportation requirements for oil used in electricity generation. These rows are specified as follows:

$$\sum_{R}\sum_{T}\sum_{S} TOL_{yRTS} - \sum_{d} QOL_{yd} \leq 0 \quad (3\text{-}15)$$

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 ($CBTB_{yr}$). 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 using a series of decision variables (QBM_{yNd}). Biomass consumed in the industrial sector ($QBMIN_{yN}$) and used for ethanol production ($QBMET_{yN}$), both of which are determined in the end-use demand models, represent competing demands for the available biomass supplies.

$$(3\text{-}16) \qquad \sum_r \sum_R CBTB_{yr} \bullet OPB_{yrR} + \sum_r \sum_R \sum_A \sum_B \sum_C TBM_{yrRABC} + QBMIN_{yN} + QBMET_{yN} - \sum_d QBM_{yNd} \le 0$$

for every biomass 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 unit so the available capacity is divided into retrofit categories A to represent the corresponding variations in cofiring capability .[24] For each cofiring category, additional cofiring levels B can be achieved by incurring additional transportation costs for incremental biomass supplies.

These equations insure 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_{yrA}) and new retrofit decisions (BCF_{yrA}). The transportation of biomass for cofiring in coal capacity type C in coal region N (TBM_{yrRABC}) is converted to the equivalent generating capacity by dividing by the product of the corresponding cofiring level ($CFLEV_{AB}$) and the fuel use per unit of capacity ($CFBTU_{yNA}$).[25] Therefore, Equation (3-17) insures that coal-fired capacity using biomass does not exceed the existing and new retrofitted capacity.

$$(3\text{-}17) \qquad \sum_r \sum_R \sum_B \sum_C TBM_{yABNC} / (CFBTU_{yNA} \cdot CFLEV_{AB}) - ECF_{yNA} - BCF_{yNA} \le 0$$

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

Biomass Cofiring Production Balance Rows. This set of constraints insure 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 fuel region R in year y, TBM_{yABRC} describes the consumption of biomass fuels for use in coal plants and TCL_{yJRCa} represents the corresponding transportation of coal. The coefficient of TBM_{yrRABC} is the ratio of the coal share to the biomass share. Therefore,

[24] 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 Energy Information Administration staff and analysts from the Electric Power Research Institute (EPRI) and the Antares Group, Incorporated. These inputs are summarized in Appendix 3.D.

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

Equation 3-18 limits fuel use of biomass relative to coal according to the retrofitted cofiring levels, as follows:

$$(3\text{-}18) \qquad \sum_{r} \sum_{R} \sum_{A} \sum_{B} TBM_{yrRABC} \bullet (1 - CFLEV_{AB}) / CFLEV_{AB} - \sum_{J} \sum_{R} \sum_{a} TCL_{yJRCa} \leq 0$$

for each coal capacity type C and Fuel R in year y.

Emissions. These constraints limit the emissions produced as a result of electricity generation. The equations below are described for SO_2, NO_X, and mercury emissions, which are restricted by current regulations. The ECP can also represent similar limitations on other emissions such as carbon by substituting the appropriate emissions coefficients[26]. The ECP can accommodate multiple emissions restrictions simultaneously by incorporating each set of constraints within the model.

According to the CAAA, the allowances for SO_2 emissions may be traded nationwide among utilities and nonutilities so the corresponding limit on emissions in each year is actually national rather than regional or company-level. . Once the initial CAIR caps are imposed (in 2010), there are effectively two SO_2 regions, these CAIR states and the Western states still covered by the CAAA but not the CAIR.

Unlike the CAAA, the CAIR reduces the SO_2 emissions limit by specifying that more than one allowance is required per ton of SO_2 emitted.[27] Therefore, the emissions target is determined by the sum of the allowances allocated ($SO2L_{yo}$) divided by the number of allowances per ton of SO_2 emitted ($SO2R_{yo}$). Allowances can still be traded between the CAIR states and the remaining States covered by the CAAA, but the value of the allowance in terms of SO_2 emitted is determined by the region using the traded allowances. As a result, an allowance traded from a generator in a CAIR state would still be worth one ton of SO_2 emissions in the CAAA states. However, an allowance held by a non-CAIR state would be subject to the specified "devaluing" if purchased for use in a CAIR state.

The allowances do not have to be used in the year that they are allocated—they can be banked for future use. The SO_2 emissions in a given year can exceed the sum of the allowances by using allowances banked in a previous year (BNK_{pyo}). Conversely, allowances can be banked for use in a subsequent year (BNK_{ywo}) by reducing emissions below the specified target. The emissions limit for a given year is adjusted to represent additions or withdrawals from the bank.

Potentially, each capacity type may produce emissions although coal-fired plants produce most of the emissions. The amount of emissions produced depends on the fuel used, pollution control devices installed (if any), and amount of electricity produced. For coal capacity, the decision variable TRC_{yJRCa} describes the coal transported for use in power plants and $SO2_{yJRC}$ represents the corresponding emission rate for SO_2.[28] The product of these two terms gives the SO_2 emissions from coal. The following series of equations accumulate the total emissions by coal plant type C in fuel regions R in SO_2 region o ($SO2E_{yoC}$).

[26] Currently, limits on carbon dioxide emissions are represented in NEMS by determining a carbon allowance price that results in achieving the specified target. The ECP incorporates this cost, which discourages the operation and expansion of carbon-producing technologies.

[27] The CAIR requires that two allowances required to emit one ton of SO2 in 2010 and 2.86 allowances are needed for each ton beginning in 2015. This effectively reduces SO2 emissions targets in the CAIR stated by 50 percent and 65 percent, respectively.

[28] The use of activated carbon only affects mercury emissions so it is not reflected in the SO_2 emissions coefficient.

(3-19) $$\sum_{J}\sum_{R}\sum_{a} SO2_{yJRC} \bullet TRC_{yJRCa} - SO2E_{yoC} \le 0$$

for every coal capacity type C and SO_2 region o in year y.

Similarly, the corresponding emissions from non-coal capacity types in electricity region r and SO_2 region o ($SO2D_{yoD}$) is the product of the operate decisions ($OPD_{yrcfams}$ and $OPDM_{yrcfams}$) and the coefficient $SO2_{yrcfms}$.

(3-20) $$\sum_{R}\sum_{f}\sum_{m}\sum_{s} SO2D_{yRf} \bullet TFL_{yrDfms} - SO2E_{yoD} \le 0$$

for every non-dispatchable capacity type D and SO_2 region o in year y.

The regional emissions limits are then represented by including the emissions by plant type and the allowance traded and banked, as follows:

(3-21) $$\sum_{C} SO2E_{yoC} + \sum_{D} SO2E_{yoD} + SO2T_{yoP} - (SO2R_{yo}/SO2R_{yP}) \bullet SO2T_{yPo} + BNK_{yw} - BNK_{py} \le LSO2_{yo}$$

for each SO_2 region o and year y.

Without CAMR, there is no federal mercury standard that specifies a national limit and trading market. Instead, there are state-level regulations that are generally based on best available control technology, or required removal rates. Coal capacity is therefore 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 plant that cannot meet the standard with its current configuration, even with activated carbon injection, would have to install additional mercury control devices in order to continue operating.

Limitations on nitrogen oxide (NO_X) emissions are implemented for specific groups of states in State Implementation Plans (SIP) and the CAIR. As with SO_2 and mercury, coal-fired capacity accounts for virtually all of the NO_x emissions resulting from power generation. Since the NO_x 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 NO_X emission rate per unit of capacity ($NOXC_{yvNCms}$) and the utilization variables (OPC_{yvNCms} and $OPCM_{yvNCms}$) describes the emissions from coal plants in NO_X containment region v ($TNOX_{yvC}$). For non-coal plants, multiplying the corresponding emission rate ($NOXC_{yvDfms}$) and the utilization variables (OPD_{yrDfms} and $OPDM_{yvNCms}$) totals these emissions ($TNOX_{yvD}$). Equations (3-22) and (3-23) identify the total NO_x from coal plant type C ($NOXE_{yvC}$) and non-coal plant type D ($NOXE_{yvD}$), respectively

(3-22) $$\sum_{N}\sum_{m}\sum_{s} NOXC_{NCms} \bullet (OPC_{yvNCms} + OPCM_{yvNCms}) - NOXE_{yvC} \le 0$$

for each coal capacity type C in NOX containment region v in year y.

$$\sum_{f}\sum_{m}\sum_{s} \mathbf{NOXD}_{Dfms} \bullet (\mathbf{OPD}_{yrDfms} + \mathbf{OPDM}_{yrDfms}) - \mathbf{NOXE}_{yvD} \leq \mathbf{0} \quad (3\text{-}23)$$

for each non-coal capacity type D in NOX containment region v in year y.

The last term on the left-hand side of the equation (3-24) accounts for the reduction in emissions that result from converting a coal-fired unit from an uncontrolled configuration H to a controlled configuration I . The reductions in NO_x emissions that result from retrofitting uncontrolled coal-fired units with pollution control devices ($NOXX_{yvC}$) are represented as follows:

$$\mathbf{NOXX}_{yvC} - \sum_{O}\sum_{H}\sum_{I} \mathbf{NOXR}_{yOHI} \bullet \mathbf{UNIT}_{yOH} \leq \mathbf{0} \quad (3\text{-}24)$$

for each coal capacity type C in NOX containment region v in year y.

The NO_x emissions limit ($ANOX_{yv}$) is imposed by summing up the emissions for all the plant types and subtracting the reductions from retrofits, as described in Equation 3-25.

$$\sum_{C} \mathbf{NOXE}_{yvC} + \sum_{D} \mathbf{NOXE}_{yvD} - \sum_{C} \mathbf{NOXX}_{yvC} \leq \mathbf{LNOX}_{yv} \quad (3\text{-}25)$$

for each NOX containment region v in year y.

Although carbon emissions are not currently regulated at the federal level, the ECP can represent proposed restrictions. Similar to SO_2, NO_x, and mercury, carbon emissions from fossil fuels are the product of fuel transportation quantities and the corresponding emissions rates. The carbon emissions for a coal plant depends 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, some carbon emissions are produced by generation from renewable (geothermal and municipal solid waste) plants ($CARR_y$). Equation (3-26) accumulates total annual electric power carbon emissions ($CARE_y$), as follows:

$$\sum_{J}\sum_{R}\sum_{C}\sum_{a} \mathbf{CARC}_{yJR} \bullet (1 - \mathbf{CARR}_{C}) \bullet \mathbf{TRC}_{yJRCa} +$$
$$\sum_{R}\sum_{D}\sum_{f}\sum_{S} \mathbf{CARD}_{yf} \bullet (1 - \mathbf{CARR}_{D}) \bullet \mathbf{TFL}_{yRDfS} + \mathbf{CARO}_{y} - \mathbf{CARE}_{y} \leq \mathbf{0} \quad (3\text{-}26)$$

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 proposed legislation has included incentives for building new capacity with CCS by allocating bonus allowances based on the carbon captured by this technology.

Essentially, these bonus allowances represent a credit that encourages CCS by reducing the impact of carbon cost.

For new coal-fired capacity (BLD_{yrRcE}), the carbon captured by CCS depends on the carbon content ($CARC_{yJR}$), the utilization rate ($CFAC_{yrC}$), the heat rate ($HRTE_{yrC}$), and the carbon removal rate ($CARR_C$). Since there are 8.76 (thousands) of hours per year, the carbon removed for new coal-fired capacity (BLD_{yrRcE}) is given by

$$\mathbf{CFAC}_{\mathbf{yrc}} \bullet 8.76 \bullet (\mathbf{HRTE}_{\mathbf{yrc}} \bullet 0.000001) \bullet \mathbf{CARC}_{\mathbf{yJR}} \bullet \mathbf{CARR}_{\mathbf{c}} \quad (3\text{-}27)$$

in year y.

The reduction in the cost coefficient for the new capacity is the product of the carbon capture determined by Equation (3-27), the specified bonus allowances for CCS ($CCSB_y$), and the carbon allowance price ($CCAR_y$), summed over the years y. Similarly, the CCS credit for gas-fired plants is obtained by substituting the corresponding coefficients for that technology.

Carbon emissions can also be reduced by retrofittinge existing coal-fired units with CCS equipment, which requires capital and operating expenditures, reduces efficiency, and derates capacity. As with new plants with CCS, the reduction emissions from existing coal plants is described by Equation (3-26). Existing uncontrolled units are converted to controlled capacity types C, which have carbon removal rates $CARR_C$.

Some states have combined to enact or consider regional caps on greenhouse gas emissions. In particular, a group of ten Northeastern and Mid-Atlantic States have formed the Regional Greenhouse Gas Initiative (RGGI), which is an agreement to limit future carbon emissions.[3] Regional carbon limits for RGGI or other containment areas Q in year y ($LCAR_{yQ}$) are specified as follows:

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

$$\sum_{R \in Q} \sum_{D} \sum_{f} \sum_{S} \mathbf{CARD}_{\mathbf{yf}} \bullet (1 - \mathbf{CARR}_{\mathbf{D}}) \bullet \mathbf{TFL}_{\mathbf{yRDfS}} \leq \mathbf{LCAR}_{\mathbf{yQ}} \quad (3\text{-}28)$$

for every containment area Q in year y.

National Short-Term Supply Cost Adjustments. The 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 operation personnel and equipment.

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

In the 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 increase. Capacity builds in a given year can be up to 15% above a base amount ($CPBAS_{yc}$) in a given year without a cost adjustment. The base amount is equal to the greatest amount of capacity brought on line in a single year over the last ten years, for each technology. If no existing capacity is online, then an off-line 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 115% of the base amount for the first step, 85% 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. The cost multiplier for the second and third steps are calculated from the following function:

(3-29)
$$\mathbf{CST_{ycE}} = \left(\frac{\mathbf{C_2}}{\mathbf{C_1}} - \mathbf{a_{thresh}}\right)^{\frac{\ln(1+a_2)}{\ln(1+a_1)}}$$

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

a_{thresh} = threshold above which elasticity is active, defined as percent increase based on current installed capacity (i.e. 15%)

a_1 = increase in capital cost for every a_2 increase in capacity, fraction

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 by changing this value 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:

(3-30)
$$\sum_{\mathbf{r}} \mathbf{BLD}_{\mathbf{yrcE}} + \sum_{\mathbf{r}} \sum_{\mathbf{e}} \mathbf{BDI}_{\mathbf{yecrE}} \leq \mathbf{CPLIM}_{\mathbf{ycE}}$$

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

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

Analogous constraints exist for intermittent and renewable builds. The objective function coefficients for the appropriate build vectors ($CBLD_{yrcE}$, $CBDI_{yecrE}$, $CRNW_{yrnE}$, $CBRI_{yenrE}$, $CINT_{yriE}$, $CBII_{yeirE}$) represent the overnight cost multiplied by the cost multiplier for each supply step, as calculated in (3-29).

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 uneconomic. Production from these plants is given by the product of capacity utilization rate (ELA_{yrcml}), the hours (in thousands) in each load segment ($LHRS_l$), and the operate decision variable (OPM_{yrQcms}). Therefore, the must-run constraints are given by

$$\sum_s \sum_m \sum_l \mathbf{ELA_{yrcml} \bullet LHRS_l \bullet OPM_{yrRcms} \geq MRUN_{yrc}} \quad (3\text{-}31)$$

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:

$$\sum_s \mathbf{SHOURS_s \bullet PMC_{yrQCs} - 8.76 \bullet CPMR_{rC} \bullet \sum_O \sum_H UNIT_{yrQOH} - 8.76 \bullet CPMR_{rC} \bullet \sum_O \sum_I UNIT_{yrQOI}} - \mathbf{8.76 \bullet \sum_{j=1}^{y} \sum_E CPMR_{rC} \bullet BLD_{jrQCE} \geq 0} \quad (3\text{-}32)$$

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

In the first term, $SHOURS_s$ represents the number of hours in season s (in thousands of hours) and PMC_{yrCs} 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. There are 8.76 thousands of hours in a year, so the terms $8.76 \bullet CPMR_{rC} \bullet UNIT_{yOH}$ and $8.76 \bullet CPMR_{rC} \bullet UNIT_{yOI}$ define the annual maintenance requirements for uncontrolled and controlled coal plants, respectively. Similarly, the term $8.76 \bullet CPMR_{rC} \bullet BLD_{jrCE}$ 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_{yrQCs}) and the variables for existing must-run units

($UNTM_{yrQOH}$ and $UNTM_{yrQOI}$). The last term of Equation (3-35) describes maintenance for new capacity, so it is removed in this case since must-run capacity only involves existing units.

$$\sum_s SHOURS_s \bullet PMM_{yrQCs} - 8.76 \bullet CPMR_{rC} \bullet \sum_O \sum_H UNTM_{yrQOH} - 8.76 \bullet CPMR_{rC} \bullet \sum_O \sum_I UNTM_{yrQOI} \geq 0 \quad (3\text{-}33)$$

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 substituted into the equation, as follows:

$$\sum_s SHOURS_s \bullet PMC_{yrDs} - 8.76 \bullet CPMR_{rD} \bullet EXD_{yrQD} - 8.76 \bullet \sum_x CPMR_{rD} \bullet EXDR_{rQDx} - 8.76 \sum_{j=1}^{y} \sum_E CPMR_{rD} \bullet BLD_{jrQDE} \geq 0 \quad (3\text{-}34)$$

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_{yrDs}) and the existing capacity (EXM_{yrD}). It is assumed that there are no retirements or additions of must-run capacity, so the last two terms of Equation (3-37) are removed. The resulting constraint is given by

$$\sum_s SHOURS_s \bullet PMM_{yrDs} - 8.76 \bullet CPMR_{rD} \bullet EXM_{yrQD} \geq 0 \quad (3\text{-}35)$$

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 times width) requirement. Since 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 (gigawatts) 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_{yrl}), which corresponds to its 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 it would not contribute to those load segments with lower capacity requirements. The contribution of a dispatchable capacity type towards meeting the requirements for a given load segment is the product of the capacity assigned to that mode of operation for coal plants (OPC_{yrRCms} and $OPCM_{yrRCms}$) and noncoal capacity ($OPD_{yrRDfms}$ and $OPDM_{yrRCms}$) and the respective derating factors (ELA_{yrCml} and ELA_{yrDml}).

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 and thus precluding the addition of new unplanned capacity. Storage technologies can contribute to the load as regular capacity, but their storage requirements will add to the load requirements. The model optimizes the use of these technologies and when to replace the storage requirement.

Also, generating capacity with intermittent energy sources (Existing - EXI_{yri}, New - INT_{yri}, New Import -BII_{yeir}) can be used to satisfy energy requirements in those load segments for which input energy is fully or partially available. For example, solar capacity can be used during those load segments in which the sun is shining. Finally, load can be met from Canadian hydroelectric power (OCH_{yrh}).

(3-36)
$$\begin{aligned}
&\sum_R \sum_C \sum_m \sum_l ELA_{yrCml} \bullet OPC_{yrRCms} + \sum_R \sum_C \sum_m \sum_l ELA_{yrCml} \bullet OPCM_{yrRCms} \\
&+ \sum_R \sum_D \sum_f \sum_m \sum_l ELA_{yrDml} \bullet OPD_{yrRDms} + \sum_R \sum_D \sum_f \sum_m \sum_l ELA_{yrDml} \bullet OPDM_{yrRDms} \\
&+ \sum_R ELB_{yr} \bullet OPB_{yrR} + \sum_n ELR_{yrn} \bullet OPR_{yrn} \\
&+ \sum_i \sum_{z=1}^{y} ELI_{zril} \bullet INT_{zri} + ELH_{zril} \bullet OPH_{yrl} - STX_{yrsl} \\
&+ \sum_i \sum_e \sum_{z=1}^{y} ELI_{zril} \bullet TLOSS_{zer} \bullet BII_{zeri} \sum_h OCH_{yrh} \\
&+ \sum_e TLOSS_{yer} \bullet TRE_{yersl} - \sum_g TRE_{yrgsl} \geq ELC_{yrl}
\end{aligned}$$

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

Transmission Constraints. For each electricity region r, these equations limit the total amount of power that can be imported from other regions e by the incoming interregional transmission capability for region r. These imports are limited as follows:

(3-37)
$$\sum_e TRE_{yersl} \leq IMP_{yrsl}$$

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

The corresponding limits for exports are given by

(3-38) $$\sum_{g} \mathbf{TRE}_{\mathbf{yrgsl}} \leq \mathbf{EXP}_{\mathbf{yrsl}}$$

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

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 insure 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}). [29] The available capacity is adjusted for planned maintenance (PMC_{yrRcs}). These equations also determine retirements for coal plants. 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 the 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 units O of uncontrolled configuration type H, the production balance rows are given by

(3-39) $$\sum_{m} \mathbf{OPC}_{\mathbf{yrRcms}} + \mathbf{PMC}_{\mathbf{ysRrc}} - \sum_{J=1}^{y} \sum_{E} \mathbf{BLD}_{\mathbf{jrRDE}} - \sum_{o} \mathbf{UNIT}_{\mathbf{yrROH}} \leq \mathbf{0}$$

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 as a separate, but similar set of constraints.

(3-40) $$\sum_{m} \mathbf{OPCM}_{\mathbf{yrRcms}} + \mathbf{PMM}_{\mathbf{ysRrc}} - \sum_{o} \mathbf{UNTM}_{\mathbf{yrROH}} \leq \mathbf{0}$$

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 units of controlled configuration type H are derived by substituting the decision variables for dispatchable units ($UNIT_{yrROI}$) into Equation (3-39) and must-run plants ($UNITM_{yrROI}$) into (3-40)..

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

[29] Coal capacity is represented at the unit-level in order to determine retofits for pollution control equipment, which tend to be site-specific. Since these decisions are not included for other fossil technologies, existing oil and gas capacity is represented at a more aggregate level.

units that can be retired if the capacity is considered uneconomic ($EXDR_{rDx}$). 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:

$$\sum_{f}\sum_{m} OPD_{yrRDfms} + PMC_{ysrRD} - \sum_{J=1}^{y}\sum_{E} BLD_{jrRDE} - CSHR_{yrRD} \bullet EXD_{yrD} - \sum_{x} CSHR_{yrRD} \bullet EXDR_{yrDx} \leq 0 \quad (3\text{-}41)$$

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

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

$$\sum_{f}\sum_{m} OPDM_{yrRDfms} + PMM_{ysrRD} - EXDM_{yrRD} \leq 0 \quad (3\text{-}42)$$

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.

$$OPR_{yrn} - \sum_{j=1}^{y}\sum_{E} RNW_{jrnE} - EXR_{yrn} \leq 0 \quad (3\text{-}43)$$

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

For existing hydro capacity, the electricity production 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 but the seasonal capacity factor (CFR_{yrns}).

$$\sum_{l} OPH_{yrl} \bullet ELR_{yrl} / CFR_{yrns} - EXH_{yrs} \leq 0 \quad (3\text{-}44)$$

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. 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 1.36, requiring 36% 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.

(3-45) $$\sum_{l} \mathbf{OPH}_{yrl} \bullet \mathbf{STFAC}_{i} \bullet \mathbf{LHRS}_{l} - \sum_{l} \mathbf{LHRS}_{l} \bullet \mathbf{STX}_{yrsl} \leq \mathbf{0}$$

for every season s in year y in EMM region r, for pumped storage and demand storage technologies only.

International. There is also a set of production balance rows that allocate capacity obtained through the early development of international generation projects. Power from a particular foreign project is derated to describe the current availability of power. More than one U.S. region can buy power from an international region, and the utilization shares between the multiple regions can change from one planning year or cycle to the next. Domestic utilities are required to commit to the purchase of all output from a project between an accelerated project start date and the project start date announced by the foreign utility. Further, all project start dates must conform to a reasonable lead time requirement. For example, if a Canadian hydro project is scheduled to start generation in 2010 to serve Canadian needs, then domestic utilities can accelerate the project start date by committing to purchase all the output of the project from the current year plus a lead time until 2010. In 2010, this capacity is assumed to be fully committed to the Canadian needs and is no longer available to the U.S. utilities, except through economy trades determined by the Electricity Fuel Dispatch (EFD).

(3-46) $$\sum_{r} \mathbf{OCH}_{yrh} - \sum_{p} \mathbf{ELCH}_{yhp} \bullet \mathbf{ECH}_{yhp} - \sum_{P} \sum_{J=1}^{y} \mathbf{ELCH}_{jhp} \bullet \mathbf{BHC}_{jhp} \leq \mathbf{0}$$

for every international region h in year y.

Nuclear Capacity Balance Row. Nuclear capacity has low operating costs so they are typically operated at their maximum utilization rate so production balance rows are not necessary. For nuclear capacity, these rows determine the retirement and continue-to-operate decisions. The decision variable $UNTN_{yrU}$ describes the amount of capacity that the ECP determines is economic to operate. That is, if the decision variable is activated, then the operating costs are incurred. The difference between $UNTN_{yrU}$ and the available capacity, NUC_{yrU}, represents the retired capacity. The capacity balance row for nuclear is given by

(3-47) $$\mathbf{UNTN}_{yrU} \leq \mathbf{NUC}_{yrU}$$

for nuclear units U in EMM region r in year y.

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. In this section, reliability requirements are described for cost-of-service regulation and are based on prespecified reserve margins. Planning decisions will have to be implemented if the total capacity requirement (RMQ_{yr}) exceeds the existing capacity ($\sum_c EXC_{yrc}$ + $\sum_c EXCR_{yrcx}$ + $\sum_n EXR_{yrn}$ + $\sum_i EXI_{yri}$). Available capacity can be increased by building new capacity—either dispatchable (BLD_{yrcE}), renewable (RNW_{yrnE}) or intermittent (INT_{yriE}). For an intermittent technology, its capacity credit (RMI_{yri}) will depend on its ability to provide electricity when the peak demand occurs. In addition, the amount of capacity is affected by imports and exports (TRE_{yrcg} , TRE_{yecr}) and by Canadian hydroelectric imports (BCH_{yrp}). Distributed generation technologies (DGN_{yrt}) operate during peak load and also contribute to reliability.

The reserve margin constraint is formulated as follows:

$$\begin{aligned}(3\text{-}48)\quad & \sum_c \sum_{j=1}^{y} BLD_{jrcE} + \sum_i \sum_{j=1}^{y} INT_{jriE} \bullet RMI_{jri} + \sum_n \sum_{j=1}^{y} RMR_{jrn} \bullet RNW_{jrnE} \\ & + \sum_C EXC_{yrC} + \sum_D EXD_{yrD} + \sum_D \sum_x EXDR_{yrDx} + \sum_n EXR_{yrn} \cdot RMR_{yrm} \\ & + \sum_p \sum_{j=1}^{y} BCH_{yhp} + \sum_t \sum_q DGN_{yrqt} + \sum_g \sum_c TRE_{yrcg} - \sum_e \sum_c TRE_{yecr} \geq RMQ_{yr}\end{aligned}$$

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. Under traditional cost-of-service regulation, the reserve margin typically represents a specified percentage designed to achieve a historical reliability standard. However, the industry has become increasingly deregulated and reserve margins are more market-based.

Reserve margins are dynamically determined using the marginal demand price and the marginal supply price. The marginal demand price is the reliability price component, which is based on the cost of unserved energy.[4] The marginal supply price is represented by the incremental cost of capacity, which is assumed to be the sum of the annualized capital cost and fixed O&M cost of a combustion turbine.

For each EMM region r, the ECP searches for the reserve margin that equilibrates the reliability price and the cost of capacity. If the amount of reserve capacity is too low, then there will be too much unserved energy and the corresponding reliability price will be relatively high. In this case, the reserve margin is increased because new capacity can be economically added until the reliability price no longer exceeds the cost of capacity. Conversely, if there is too much capacity then there will be comparatively few periods when demand cannot be met and the resulting reliability price will be too low to recover the cost of new supplies. In this instance, the reserve capacity requirement is lowered until the reliability price increases sufficiently to justify investment in additional capacity.

[4] The derivation of the reliability price adjustment is described in Chapter 5 (Section 5B).

International Firm Power Imports Limit. The firm power imports constraints limit the development of foreign generation projects by the available supply.

(3-49) $$\sum_{y} \mathbf{BCH}_{\mathbf{yhb}} \leq \mathbf{CHYL}_{\mathbf{hb}}$$

for every project b in international region h.

Intermittent Build Limit. The limits on new intermittent capacity result from a combination of resource constraints and new technology penetration limits.

(3-50) $$\sum_{j=1}^{y} \sum_{E} \mathbf{INT}_{\mathbf{jriE}} + \sum_{e} \sum_{j=1}^{y} \sum_{E} \mathbf{BII}_{\mathbf{jeirE}} \leq \mathbf{INTL}_{\mathbf{ir}}$$

for every intermittent technology i and EMM region r.

Renewable Build Limit. The limit on new renewable capacity result from a combination of resource constraints and new technology penetration limits.

(3-51) $$\sum_{j=1}^{y} \sum_{E} \mathbf{RNW}_{\mathbf{jrnE}} + \sum_{e} \sum_{j=1}^{y} \sum_{E} \mathbf{BRI}_{\mathbf{jenrE}} \leq \mathbf{RNWL}_{\mathbf{nr}}$$

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.

(3-52) $$\sum_{t} \mathbf{DGN}_{\mathbf{yrtq}} \leq \mathbf{DGNL}_{\mathbf{yrq}}$$

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

Demand Storage Build Limit. The load shifting technology is very attractive due to its ability to avoid peak operating costs, however, there is a limit to how much the demand can be reduced due to these methods, which require customers to curtail load at peak times. A fixed input assumption determines the maximum percent of peak load that can be met by the demand storage technology in each year, and this constraint limits total demand storage capacity to $STLIM_{ry}$, which is the input percent for the year multiplied by the peak demand in the region.

(3-53) $$\mathbf{BLST}_{\mathbf{yr}} + \mathbf{EXST}_{\mathbf{yr}} \leq \mathbf{STLIM}_{\mathbf{yr}}$$

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

(3-54)

$$\sum_{O}\sum_{I} \mathbf{UNIT_{yOI}} \leq \mathbf{FGDL_{y}}$$

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 units O currently without CCS equipment that are converted to a carbon-controlled configuration I in year y, then the limit is specified by Equation (3-55)

(3-55)

$$\sum_{O}\sum_{I} \mathbf{UNIT_{yOI}} \leq \mathbf{CCSL_{y}}$$

For every year y.

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

(3-56)

$$\sum_{i}\sum_{l}\mathbf{ELI_{yril}} \bullet \mathbf{EXI_{yri}} + \sum_{i}\sum_{j=1}^{y}\sum_{l}\sum_{E}\mathbf{ELI_{yril}} \bullet \mathbf{INT_{jriE}}$$
$$+ \sum_{i}\sum_{e}\sum_{j=1}^{y}\sum_{l}\sum_{E}\mathbf{ELI_{yril}} \bullet \mathbf{BII_{jeirE}} - \mathbf{PINT} \bullet \mathbf{GEL_{yr}} \leq \mathbf{0}$$

for every region r and year y.

Renewable Portfolio Constraint. Renewable Portfolio Standards (RPS) are included in many of the Federal and State proposals for deregulating the electric power industry. A 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 of purchase "credits" from other suppliers with excess renewable generation.

The RPS proposals differ according to their respective definitions of renewable technologies. Solar, wind, biomass, and geothermal are typically included, but some proposals exclude generation from hydroelectric and/or municipal solid waste plants. 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 the ECP, the RPS is represented by adding a set of constraints that specify the minimum level of renewable generation for a given year. Regional and national equations are included in order to represent the respective requirements, if appropriate. 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 percent of electricity sales. The regional rows are represented as follows:

(3-57)

$$\sum_{i}\sum_{l}\mathbf{ISHR_{i}} \bullet \mathbf{ELI_{yril}} \bullet \mathbf{LHRS_{l}} \bullet (\mathbf{EXI_{yri}} + \sum_{z=1}^{y}\sum_{E}\mathbf{INT_{zriE}})$$
$$+ \sum_{n}\sum_{l}\mathbf{RESR_{n}} \bullet \mathbf{ELR_{yrn}} \bullet \mathbf{LHRS_{l}} \bullet (\mathbf{EXR_{yrn}} + \sum_{z=1}^{y}\sum_{E}\mathbf{RNW_{zrnE}})$$
$$\sum_{A}\sum_{B}\sum_{N}\sum_{C}\mathbf{RSHR_{n}} \bullet \mathbf{TBM_{yANC}} \bullet \mathbf{1000/HRD_{yNC}} - \mathbf{RPSR_{yr}} \geq \mathbf{0}$$

For every region r and year y.

The first term of the equation accounts for generation from existing and new intermittent technologies. For each load segment l, the derating factor (ELI_{yril}) describes the fraction of total capacity that is utilized in that segment (i.e., 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 the 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 heatrate 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 (GEL_{yr}) represents the total regional generation produced from all sources. Multiplying this quantity by the RPS fraction ($RBND_y$) provides the minimum renewable generation requirement.

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 the 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:

$$\mathbf{EPRENEW}_y \bullet (1 + \mathbf{AVGDCR}_y)^y / \mathbf{UPGNPD}_y \quad \text{(3-58)}$$

for year y 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)

$UPGNPD_y$ = 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

$$\mathbf{EPRENEWR}_{yr} \bullet (1 + \mathbf{AVGDCR}_y)^y / \mathbf{UPGNPD}_y \quad \text{(3-59)}$$

Technology Penetration

The ECP contains a component that represents changes in cost and performance characteristics for different capacity types, particularly new technologies. It addresses initial cost estimates (technological optimism), cost reductions as commercialization occurs (learning), uncertainty

associated with capacity expansion (risk), and efficiency improvements.[32] This component also contains a market-sharing 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. Therefore, the inputs for these plant types include only the traditional project contingency factor, which typically ranges from 5 to 10 percent.[33]

However, there are no data on realized costs for new technologies. As a result, capital costs for new generating technologies are based on engineering estimates. The ECP incorporates a technological optimism factor, which is an additional contingency rate that represents the tendency to underestimate costs for new technologies.[34] 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 3). Often a new technology design incorporates parts of existing designs, which will have less uncertainty in the cost estimates. By calculating the optimism factor 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 1st-of-a-kind cost is also an input (e.g., a 10 percent technological optimism factor equals 1.10). It is assumed that this factor decreases linearly until the actual costs and estimates are the same (e.g., 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 4). The slope of the line that describes the decrease in the technological optimism factor is given by

(3-60) $$\mathbf{SLOPE_D = (1 - OPTFACO_D)/(UNITL_D - UNITB_D)}$$

where:

$OPTFAC0_D$ = Initial Technological Optimism Factor for Design Component D

[32] For greater detail on the methodology for technological optimism, learning, and risk, see Energy Information Administration, *NEMS Component Design Report, Modeling Technology Penetration* (Washington, DC, March 1993). The inputs for these factors are contained in Energy Information Administration, *Assumptions to the Annual Energy Outlook 2004*, DOE/EIA-0554(2004) (Washington, DC, February 2004).

[33] 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".

[34] 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).

$UNITL_D$ = Number of Units of Capacity with Component Type D Completed When Technological Optimism is No Longer Observed

$UNITB_D$ = Number of Units of Capacity with Component Type D Completed When Technological Optimism Factor is First Applied (i.e. 0)

The technological optimism factor $OPTFAC_{yD}$ for component type D in year y is then given by

(3-61) $$\mathbf{OPTFAC_{yD} = OPTFAC0_D + SLOPE_D \bullet UNITS_{yD}}$$

$$\text{for } UNITS_{yD} < UNITL_D$$

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.

(3-62) $$\mathbf{OPTFAC_{yc} = \sum_D CSTWT_{cD} \cdot OPTFAC_{yD}}$$

where:

$CSTWT_{cD}$ = Share of Initial Cost Estimate of Capacity Type c contributed to by Design Component D

Learning Methodology. The 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 3-step learning curve is utilized 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:[35]

(3-63) $$C_N = C_I \cdot (\frac{N}{I})^b$$

where:

C_N = Cost at current capacity level (Dollars per Kilowatt)

C_I = Initial Cost estimate (Dollars per Kilowatt)

N = Current capacity

I = Initial capacity (set to typical unit size if no units online)

Rearranging Equation (3-61), the exponent for each step s (b_s) can be determined by letting (N/I) equal 2 (i.e., considering a doubling of capacity). That is,

(3-64) $$b_s = \ln(1 - LCR_S) / \ln(2)$$

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,

(3-65) $$C_2 = C_1 \cdot 2^b; C_4 = C_1 \cdot 4^b; C_8 = C_1 \cdot 8^b; \cdots$$

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.

(3-66) $$C_N = C_1 \cdot LF_N$$

Substituting the right-hand side of (3-64) for C_N in equation (3-61) yields

(3-67) $$LF_N = (\frac{N}{I})^b$$

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.

[35] The methodology for determining learning factors is discussed in greater detail in Independent Project Analysis, Incorporated, "An Analysis of the Potential for Cost Improvement in Emerging Power Generation Technologies" (Reston, Va., June 1993).

(3-68)
$$\mathbf{LRNFAC_{ye} = \sum_{D} CSTWT_{cD} \bullet LRNFAC_{yD}}$$

Technological Improvements in Heatrates. The ECP also includes improvements in heatrates, which describe the amount of fuel input required to produce a kilowatthour of electricity. For each of technology, it is assumed that the annual reduction in the heatrate is constant and occurs over a prespecified time period. The heat rate for technology type c in a particular year is given by

(3-69)
$$\mathbf{EPPHRT_{yc} = EPPHRT0_c - (EPPHRTN_c - EPPHRT0_c)\left(\frac{y - UPDHRY0_c}{UPDHRYN_c - UPDHRY0_c}\right)}$$

for $UPDHRY0_c \le y \le UPDHRYN_c$

$EPPHRT_{yc} = EPPHRT0_c$ for $y < 1995$

$EPPHRT_{yc} = EPPHRTN_c$ for $y > 2010$

where:

$EPPHRT_{yc}$ = heatrate for technology type c in year y

$EPPHRT0_c$ = initial heatrate for technology type c

$EPPHRTN_c$ = final heatrate for technology type c

$UPDHRY0_c$ = last year for initial heatrate for technology type c (i.e., year before heatrate improvements begin)

$UPDHRYN_c$ = last year of learning for heatrate for technology type c

Market-Sharing Algorithm. The 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:[36]

(3-70)
$$\mathbf{MS_i = MC_i^a / \sum_j MC_j^a}$$

where:

MS_i = Market Share for the ith Technology

MC_i = Marginal Cost for the ith Technology

a = Exponent of Logit Function

In Equation (3-68), market shares are determined on the basis of marginal costs. In the ECP, the competitiveness of the different technologies is compared using the *reduced cost* from the LP

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

model, which describes the marginal cost reduction required for a particular option to be selected.[37] In this algorithm, MC_i is represented using the following ratio:

(3-71) $$\mathbf{CSTRATIO_{yrc} = (CBLD_{yrcE} - RC_{yrcE})/CBLD_{yrcE}}$$

where:

$CSTRATIO_{yrcE}$ = Ratio of Required Cost to Actual Cost for Building Capacity Type c Beginning Operation in Year y in Region r at Short Term Supply Step E (Scalar)

$CBLD_{yrcE}$ = Investment Cost to Build Capacity Type c With Initial Online Year y in Region r at Short Term Supply Step E (Millions of Dollars / Gigawatt)

RC_{yrcE} = Reduced Cost to Build Capacity Type c With Initial Online Year y in Region r at Short Term Supply Step E (Millions of Dollars / Gigawatt)

Since RC_{yrcE} is greater than or equal to zero, $CSTRATIO_{yrcE}$ 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, $CSTRATIO_{yrcE}$ is set to 0 if $CSTRATIO_{yrcE}$ is less than (1 - EPMSTOL), so that the corresponding market share will be 0. After $CSTRATIO_{yrcE}$ has been determined for all options evaluated by the market-sharing algorithm, this ratio is incorporated into Equation (3-68) to determine the individual market shares for each technology choice. That is,

(3-72) $$\mathbf{MS_{yrcE} = (CSTRATIO_{yrcE})^a / \sum_y \sum_c \sum_E (CSTRATIO_{yrcE})^a}$$

A "less-competitive" technology has a comparatively high reduced cost relative to its actual cost, thereby resulting in a lower value for $CSTRATIO_{yrcE}$. When the exponent a is applied, the numerator in Equation (3-70) declines rapidly resulting in a lower market share compared to other technologies with higher values for $CSTRATIO_{yrcE}$.

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

(3-73) $$\mathbf{BMS_{yrcE} = MS_{yrcE} \cdot TOTBAS_r}$$

Finally, the capacity expansion decisions that were selected by the LP model (BLP_{yrcE}) must be decreased to account for the new capacity that was reallocated ($TOTNBS_r$). This is accomplished by Equation (3-72) and Equation (3-73), which reduce each of the original decisions in proportion to their share of the total market.

(3-74) $$\mathbf{TOTNBS_r = \sum_y \sum_c \sum_E BMS_{yrcE}}$$

[37] An option selected by the LP model has a reduced cost of 0.

where:

BLD_{yrcE} = Market-Sharing Build Decisions for Capacity Type c Beginning Operation in Year y in Region r at Short Term Supply Step E (Gigawatts)

(3-75) $$BLP'_{yrcE} = BLP_{yrcE} - TOTNBS, \cdot (BLP_{yrcE} / TOTBAS_{r})$$

where:

BLP_{yrcE} = Revised LP Build Decisions for Capacity Type c Beginning Operation in Year y in Region r at Supply Step E (Gigawatts)

Demand Expectations

The EMM can determine demand expectations using an alternative method to the original approach used by the Integrating Module.[38] 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, which is implemented by specifying the initial year (GRW-XYR), is described below.

(3-76) $$GDEM_{sry} = DEM - WGHT_{sr} * GDEM_{srl} + (1 - DEM - WGHT_{sr}) * DEM - GRW_{sr}$$

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)

$GDEM_{srl}$ = previous expected annual growth rate for electricity demand in sector s in region r in year l = y-1 (scalar)

DEM_GRW_{sr} = initial expected demand growth rate (scalar)

[38] For more information on the methodology to determine adaptive expectations, see Energy Information Administration, *Integrating Module of the National Energy Modeling System: Model Documentation 2008*, DOE/EIA-M057(2008) (Washington, DC, June 2008).

Appendix 3.A. ECP Data Flows

The subroutine *ELECP* initializes variables and calls *ECPOML*, which controls the setup and solution of the LP model. *ECPOML* initializes the LP database and sets up the starting matrix using OML subroutines. It then executes a series of FORTRAN subroutines that control the revision of coefficients for the 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. Once the matrix revisions are completed, the LP model is solved and the solution retrieved using OML subroutines.

Matrix Revisions

EP$ALLOW sets up the right-hand side of the emissions constraints for each year of the planning horizon. For SO_2, the right-hand side represents the limit corresponding to the sum of the emissions allowances allocated in accordance with the Clean Air Act Amendments of 1991 or other proposed limits. Restrictions on SO_2 emissions are implemented as national constraints since allowances can be traded. If emissions allowances have been banked by over complying in previous years (i.e., emitting less sulfur dioxide than the sum of the allowances), then the right-hand side is adjusted accordingly. *EP$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 oxide (NOX) and mercury emissions.

EP$ETT imposes interregional transmission constraints and incorporates limits on imports from new Canadian hydroelectric projects. The corresponding contributions to reserve margin requirements are also included. *EP$ETT* calls *GETEIJ*, which is a data processing routine that obtains transmission and trade data from an EMM input file.

EP$COAL creates the model structure for retirement and retrofit decisions for existing coal capacity. It represents the costs of retiring plants, continuing to operate in its present configuration, and installing control devices to reduce emissions of SO_2, NOX, and mercury, including scrubbers, low-NOX burners, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), spray dryers, and fabric filters.

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 characteristic such as Btu content and emissions rates for SO_2, NOX, mercury, and carbon dioxide. This subroutine also sets up the decision variables to retrofit and operate coal-fired capacity to cofire with biomass. These decisions can reduce emissions and/or contribute to the requirements specified in a renewable portfolio standard.

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$BLD simulates disincentives for overbuilding generating capacity such as the disallowance by public utility commissions of capital additions to the rate base for new plants that are excess capacity. Electric utilities must have sufficient generating capacity to satisfy minimum reliability requirements, which is defined as the peak demand plus an assumed amount of reserve capacity in case of unexpected demands or unavailable supply (e.g., unplanned maintenance). *EP$BLD*

revises the coefficients for constraints that limit capacity additions in excess of the minimum reliability requirements. It also uses *GETEIJ* in order to incorporate contributions to the reserve margin requirement of Canadian hydroelectric projects and plants built in one region to serve another.

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. These data are initially used in the subroutines *EPFLPRC,* which determines the expected fuel prices. These fuel prices are used to determine the coefficients for the discounted present value of fuel costs over the 20-year period in which project expenditures are evaluated.[39]

EPPMLF determines the planned maintenance and load following requirements. The planned maintenance constraints ensure that capacity is removed from service in order to perform annual maintenance. The load following structure simulates reductions in utilization rates that can occur during periods of low demand. Load following can prevent shutdowns of units that are difficult or costly to restart.

EXCUM and *EMUE* revise the coefficients of the constraints that represent capacity planning under competition. These equations determine the optimal capacity level by equilibrating the marginal cost of capacity and the marginal cost of unserved energy.

EP$MRM computes the total capacity needed to meet the reserve margin requirement. In contrast to *EP$BLD*, which places an upper limit on the amount of capacity, *EP$MRM* determines minimum capacity for insuring reliable supplies. *EP$LOAD* establishes the required allocation of capacity to meet the demand for electric power in each seasonal/time-of-day load segments 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$RPS sets up the constraints that represent renewable portfolio standards, which impose a minimum generation requirement for qualifying renewable technologies. This subroutine also can specify a maximum credit price that can be 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 (i.e., wind and solar). This 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 cofire 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, 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 (e.g., geothermal,

[39] The planning horizon for the ECP is 6 years, so the cost coefficients for the last year actually represent the total present value of expenditures incurred in years 6 through 20.

hydroelectric, biomass), excluding intermittent technologies (e.g., 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$BRNW* also imposes limits (upper bounds) on capacity additions for renewable technologies due to resource constraints, if appropriate. *EP$BDGN* determines the objective function coefficients and maximum capacity additions for each step of the distributed generation supply curves.

EP$ODSP modifies the coefficients for decision variables that describe the allocation of fossil-fuel and nuclear to meet the demand for electricity (referred to as "operate vectors"). It determines the cost of operating fossil-fuel and nuclear capacity types, based on the discounted, present value of operating expenses (fuel and variable operating and maintenance costs). These capacity types are considered "dispatchable" since they are generally available to generate electricity except for planned and unplanned outages. One of the decisions evaluated by the ECP is the mode of operation for these capacity types, which ranges from "baseload" (continuous operation except for outages) to "peaking" (operated only during periods when demand is high). The total variable cost depends on the utilization rate and the per-unit operating costs. *EP$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 (e.g., 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 on capacity, a single variable is used for intermittent technologies. The ECP essentially determines whether or not to build these capacity types because they will be operated if available since 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 (e.g., 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. It provides 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 economic to continue operating existing plants as opposed to retiring them and replacing them with other types of capacity.

Once the computations to revise the coefficients for the LP model are completed, *ECPOML* executes several OML routines to process the data, load the matrix, and solve the model. *ECPOML* then calls a series of subroutines to obtain solution values that are provided to other components of the EMM..

Solution Retrievals

EPO$BANK retrieves and stores the allowances banked in the current year. The banked allowances are provided to the Electricity Fuel Dispatching (EFD) Submodule so that the emissions limit for the current forecast year can be increased by the corresponding amount. *EPO$RPS* obtains the dual values of the renewable portfolio standard constraints, if any, and computes the levelized credit price. *EPO$TBLD* identifies national-level build limits to insure that these restrictions are not violated when the capacity decisions are reallocated by the market-sharing algorithm. *EPO$ETT* captures the decision to purchase electric power from new Canadian hydroelectric projects. This information is used to increase firm Canadian imports when evaluating subsequent dispatching and planning decisions.

EPO$COAL obtains the planning decisions to retire existing coal capacity or retrofit plants with pollution control devices. *EPO$NUC* stores retirement decisions for existing nuclear capacity.

Prior to getting the remaining planning decisions, the data processing routine *GETBLD* retrieves input data such as capital costs and the cost of capital in order to calculate the required expenditures. For each electricity supply region, *EPO$AVOID* obtains the avoided cost of electricity (the cost of producing an additional unit of electricity). This value is determined so that Renewable Fuels Module (RFM) can construct supply curves for selected technologies. *EPO$BILD* retrieves capacity expansion decisions and provides them to the EFD in order to adjust the available capacity for future dispatching decisions. *EPO$BILD* also provides investment costs for new capacity to the Electricity Finance and Pricing Submodule (EFP) to include in the revenue requirements. *EPO$BILD* also stores the retirement decisions for noncoal fossil capacity.

EPO$PM and *EPO$COF* capture the planned maintenance and cofiring decisions from the 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.

Appendix 3.B. Data Sources

This appendix provides a list of the data sources in the ECP. Each data source is accompanied by a brief description.

SURVEY FORMS

Form EIA-860

The Form EIA-860 collects data on the status of existing electric generating plants and associated equipment in the United States, and those scheduled for initial commercial operation within 5 years of the filing of this report. 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 (1000 kW) or more, and are operating or plan to be operating within 5 years of the year of this form.

Form EIA-861

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-767

The Form EIA-767 is a mandatory, annual, restricted-universe census of all electric power plants with a total existing or planned organic- or nuclear-fueled steam electric generator nameplate rating of 10 or more megawatts. The entire form is filed by approximately 700 power plants with a nameplate capacity of 100 or more megawatts. An additional 200 power plants with a nameplate capacity between 10 and 100 megawatts submit information only on fuel consumption/quality, boiler/generator configuration, and flue-gas desulfurization equipment, if applicable. The Form EIA-767 is used to collect data annually on plant operations and equipment design (including boiler, generator, cooling system, flue gas desulfurization, flue gas particulate collectors, and stack data).

Form EIA-906

Form EIA-906 collects information from regulated and unregulated electric power plants in the United States. Data collected include electric power generation, energy source consumption, end of reporting period fossil fuel stocks, and useful thermal output from cogenerators. 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 of the electric power industry and to evaluate the future of the industry. Form EIA-906 monthly respondents are a representative sample of

electric power plants by State and by energy source. Electric power plants that do not report data monthly submit data annually.

Form EIA-920

Form EIA-920 collects information from combined heat and power plants with a generating capacity of 1 megawatt (1000 kW) and above in the United States. Data collected include electric power generation, fuel consumption, fuel heat content, and fossil fuel stocks. These data are used to monitor the current status and trends of electric power generation facilities. 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 of the electric power industry. Form EIA-920 monthly respondents are a representative sample of combined heat and power plants with a generating capacity of 1 megawatt (1000 kW) and above by State and by energy source. Combined heat and power plants that do not report data monthly submit data annually.

FERC Form 1

The 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 Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF) is responsible for routine data improvements, and quality assurance activities of EIA survey data. Data improvement efforts include verification of data-keyed input by automatic computerized methods, editing by subject matter specialists, and follow up on nonrespondents. Manual edit checks include spot checking information stored on computer tapes against the survey forms, and 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 their behavior in the past and in comparison to other current fields. Data values that fall outside of prescribed ranges are verified by telephoning respondents to resolve any discrepancies.

NERC regional publications of the "Coordinated Bulk Power Supply Program Report"

A annual compilation of load and resource data that allows the ten North American Electric Reliability Councils (NERC) to assess the adequacy and reliability of bulk power supply in the NERC regions. The report contains information in three categories: 1) Peak Load/Resource and Energy/Fossil Fuel Information, 2) Existing Generation, and 3) Generation Additions. This information is filed with the Department of Energy, Office of Emergency Planning and Operations (OE) as part of the FORM EIA-411 response. FORM EIA-411 is described below.

FORM EIA-411

The Form EIA-411 is filed annually on April 1 by the ten NERC regions. The information reported includes: (1) actual energy and peak demand for the preceding year and 10 additional years; (2) existing and future generating capacity; (3) scheduled capacity transfers; (4) projections of capacity, demand, purchases, sales, and scheduled maintenance; (5) assessment of adequacy; (6) generating capacity unavailability; (7) bulk power system maps; (8) near term

transmission adequacy; (9) future critical bulk power facilities that may not be in service when required; and, (10) system evaluation criteria.

Environmental Protection Agency "Emissions Characteristics and Costs"

- Allowance Tracking System (ATS) -- database for sulfur dioxide allowances under the Acid Rain Program specified by the Clean Air Act

- NO_X Allowance Tracking System (NATS) -- data on nitrogen oxide allowances under the Ozone Transport Commission (OTC) and State Implementation Program (SIP) Call Programs

- "Analyzing Electric Power Generators Under the CAAA, Appendix 5" (Washington, DC, March 1998) -- costs for pollution control equipment

Distributed Utility Associates "Cost and Performance Characteristics for Distributed Generation"

- "Assessing Market Acceptance and Penetration for Distributed Generation in the United States" (June 1999)

Appendix 3.C Assumptions for Biomass Cofiring

Biomass cofiring characteristics depend on the type of coal-fired boiler. Cofiring costs and levels differ for cyclone and other pulverized coal units. The size of the unit also affects cofiring capability. The ECP utilizes five retrofit categories for cofiring in coal-fired capacity: (1) Cyclone boilers greater than 500 megawatts, (2) Cyclone boilers less than or equal to 500 megawatts, (3) Other pulverized coal boilers greater than 500 megawatts, (4) Other pulverized coal boilers greater than or equal to 200 megawatts and less than or equal to 500 megawatts, and (5) Other pulverized coal boilers less than 200 megawatts.

Table 5 describes the cost assumptions for the biomass cofiring categories. Table 6 contains the assumed cofiring levels. Within each category, different levels can be achieved by incurring higher transportation cost. Table 7 displays the incremental transportation costs associated with the delivery of sufficient biomass fuel to support the specified cofiring level.

Table 5. Biomass Cofiring Costs by Retrofit Category (2000 Dollars)

Retrofit Category	Capital Cost (Dollars / Kw)	Fixed O&M Cost (Dollars / Kw)
1	100	7.0
2	100	7.0
3	100	7.0
4	200	7.0
5	230	7.0

Table 6. Biomass Cofiring Levels by Retrofit Category (Percent)

Retrofit Category	Cofiring Level					
	1	2	3	4	5	6
1	2.5	5.0	7.5	10.0	12.5	15.0
2	5.0	10.0	15.0	NA	NA	NA
3	2.0	4.0	6.0	8.0	12.0	15.0
4	10.0	15.0	NA	NA	NA	NA
5	15.0	NA	NA	NA	NA	NA

NA = Not Available

Table 7. Incremental Biomass Transportation Costs by Retrofit Category and Cofiring Level

(2000 Dollars per Million Btu)

Retrofit Category	Cofiring Level					
	1	2	3	4	5	6
1	0.00	0.24	0.43	0.58	0.72	0.84
2	0.00	0.24	0.43	NA	NA	NA
3	0.00	0.24	0.43	0.58	0.84	1.01
4	0.00	0.13	NA	NA	NA	NA
5	0.00	NA	NA	NA	NA	NA

NA = Not Available

Appendix 3.D. Cost of Capital

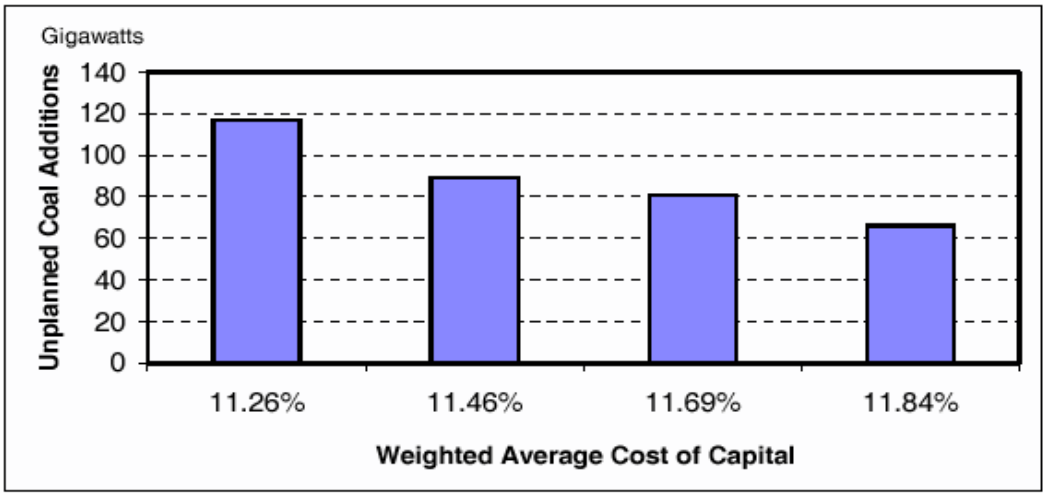
Introduction

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. The specific generating technologies that will be chosen and the fuels that they will use is part of this effort. The 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 the next 30 years and chooses the least cost mix of options. The ECP assumes that building power plants will take place in a competitive environment rather than in a rate base or regulated environment.

Each year, the assumptions and parameters for discount rates and the weighted average cost of capital (WACC)[1] are reviewed to reflect the changing nature of the power industry and to incorporate new capital market information. For example, since the AEO2004, we have increased the equity portion of project financing and the return required on equity to reflect the greater risk associated with investments in a deregulated market. The discount rate (WACC) is a very important component because the rate reflects the riskiness of the investment and affects mix of capacity additions. For instance, Figure 8 shows the sensitivity of unplanned capacity additions to discount rates; small changes in the weighted average cost capital lead to huge changes in capital intensive capacity additions.

Figure 8. Sensitivity of Capacity Additions to Discount Rates



Source*: The National Energy Modeling System: AEO 2004 Run Review,* EIA

[1] We are implicitly assuming that the project will be financed by both debt and equity and will return the expected interest payments to creditors and the expected dividends to shareholders.

This appendix explains the models, assumptions and parameters for the WACC. The appendix is organized as follows: The following section describes theoretical approaches, assumptions and parameters of the model. The subsequent section provides the model structure and computations.

Discount Rate Assumptions and Parameters

Investment Assumptions in the ECP

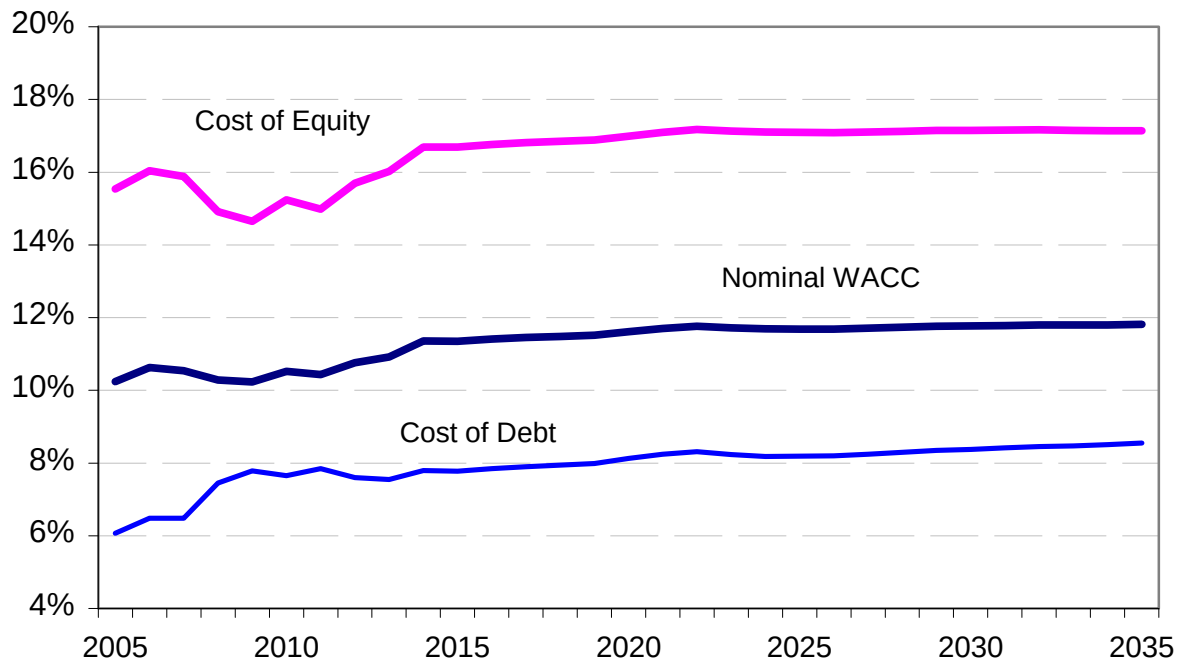
In the ECP, a traditional net present value (NPV) capital budgeting methodology is employed to perform investment feasibility. In order to do so, the following assumptions are made:

1) Power generating industry is competitive. Thus, investments for power plants are made in competitive environment that includes certain risks.

2) Different generating technologies have the same risk treatment in investment for capital budgeting purposes. That is the required rate of return (WACC) on investment is the same for all projects.

3) The discount rate (WACC) is different for each year[2], and it is shown in Figure 9.

Figure 9. Derived Nominal WACC



Source: AEO2010, NEMS Run aeo2010r.d111809a.

The WACC Overview

[2] A fixed discount rate of net present value (NPV) methodology over the life of the project for capital budgeting is simplified computations and overly restricted. Since several parameters for the cost of debt and equity in the NEMS are endogenously determined, the different WACC for each is derived by the NEMS and is used for capital budgeting. This approach is more realistic and accurate to forecast next 20 years.

The WACC equation is as follow:

$$WACC = \left(\frac{Debt}{TotalCapital}\right)k_d(1-t) + \left(\frac{Equity}{TotalCapital}\right)k_s$$

$$= (w_d)(k_d)(1-t) + (w_s)(k_s)$$

where w_d: weight of debt proportion to total capital

w_s: weight of equity proportion to total capital

k_d: cost of debt

k_s: cost of equity

t: corporate tax rate

In order to calculate the discount rate (WACC) for capital budgeting, we need to identify at least six different parameters, two endogenous[3] and four exogenous inputs. The fundamental assumptions and parameters of the variables are shown in Table 8.

Table 8. Financial Parameters and Assumptions

	Variables		Parameters	
1.	Debt fraction	45%	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 T-note rate		Endogenous	Varied
4.	Market risk premium	7.5%	Exogenous	Fixed
5.	Equity beta	1.5	Exogenous	Fixed
6.	Corporate tax rates	38%	Exogenous	Fixed
	Nominal WACC		Endogenous	Varied

It is assumed that projects will be financed by both debt and equity and will 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.

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 financial health of the industry outlook 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 would require more equity relative to total capital. However, the capital structure will be constant over the project life.

[3] These parameters, utility AA bond rate and 10-year T-note rate, are forecasted and generated by the macroeconomic module in the NEMS.

Table 9 is the capital structure assumptions for the AEO 2010.

Table 9. Capital Structure

	AEO2010
Debt fraction	45%
Equity fraction	55%

The capital structure, debt and equity proportions for investment capital, decision is made by a feasible target capital structure using a pure-play analysis. For the AEO 2009, the capital structure is composed by 45 percent of debt fraction and 55 percent of equity fraction. The decision is based on our conversations with and survey data by utility practitioners suggest to us that less than 50 percent of debt finance will be feasible due to risks associate with industry over capacity, and we also look at last five years average debt structures of airline and utility industries, as well as large-cap firms for pure-play purpose.[4]

Cost of debt

The cost of debt (k_d) is determined by the industrial Baa bond rate.

$$\text{Cost of debt}_t = k_{dt} = \text{Baa bond rate} \quad (3.D.1)$$

where k_{dt} = Cost of debt in year t

Baa bond rate_t = Industrial Baa bond rate in year t

Since the Macroeconomic module endogenously determines the industrial Baa bond rates for the forecasting period, rates (cost of debt) are different for each year. It is assumed that an average debt rating for a utility project is Baa. Therefore, the debt premium is determined by an average historical spread between the corporate 10-year Aa bond rate and Baa rate.[6]

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 or the required rate of return of any risky investment. The model is:

$$k_{st} = k_{RFt} + (EMRP)\beta_{Equity} \quad (3.D.2)$$

where k_{st} = cost of equity at year t

k_{RFt} = risk-free rate at year t

$EMRP$ = expected market risk premium (constant)

β_{Equity} = equity beta (constant)

The model requires that three variables be specified including risk-free rates, a market risk premium, and a systematic risk coefficient relative to market (beta). Since the CAPM assumes all investors have the same one-period time investment horizon such as one month, six months, or

[4] Large-cap firms have equity capitalizations greater than $6,242,000,000. For more information on the methodology to determine the large-cap, see Ibbotson Associations, *Cost of Capital: 2005 Yearbook*, Chicago, IL, 2005.

[6] See Moody s, S&P, and Fitch for the recent projects and firms debt ratings. The range of the debt ratings is also consistent with recent structured financing for power investments by investment banks, i.e., Morgan Stanley, Dean Witer, Merrill Lynch and Lehman Brothers.

one year, using Treasury bill rates as risk-free rates is not appropriate. As a result, a risk-free rate (k_{RF}) is based on 10-year Treasury note rates. The future spot 10-year Treasury note rates in the Macroeconomic module are used as estimates of expected risk-free rates in future time periods.

The expected market risk premium (*EMRP*), which is 7.5 percent, is the expected return on market (S&P 500) over the rate of 10-year Treasury note (risk-free rate). Monte Carlo simulation is used to estimate the expected market return. There have been a number of studies to estimate the expected equity risk premium utilizing 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. The EIA approach estimates the expected market risk premium using the historical market risk premium methodology with arithmetic mean of returns on both S&P 500 and government bonds.

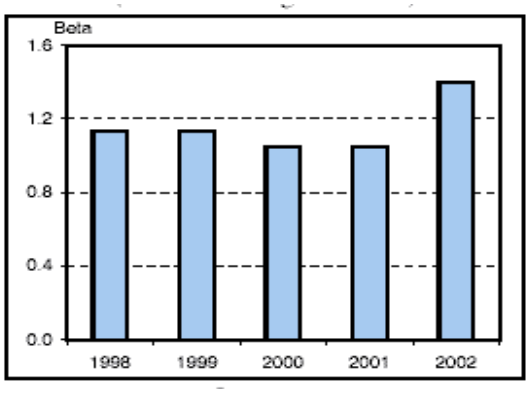
The arithmetic mean is used to estimate historical returns instead of the geometric mean, which is backward-looking and measures the change in value over more than one period. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending values. This makes the arithmetic mean return appropriate for forecasting the cost of capital.

An industry composite equity beta of the utility industry is determined by a pure play analysis with the airline and telecommunication industries. The estimated utility industry equity beta for the AEO 2009 is 1.50. Since the industry is restructuring markets, historical utility data are no longer useful to analyze statistical inferences, especially going forward. The structure and size of the both airline and telecommunication industries are an appropriate guide to the current and future utility industries. A trend of the benchmark industry betas is shown in Figure 10 and Figure 11.

The year-average beta is calculated by an average of monthly fundamental betas for each year in both figures 10 and 11. The monthly fundamental beta is a measurement of the sensitivity of a company's stock price to the overall fluctuation in the S&P 500 index price, and it is calculated for a 5 year (60 month) time period.

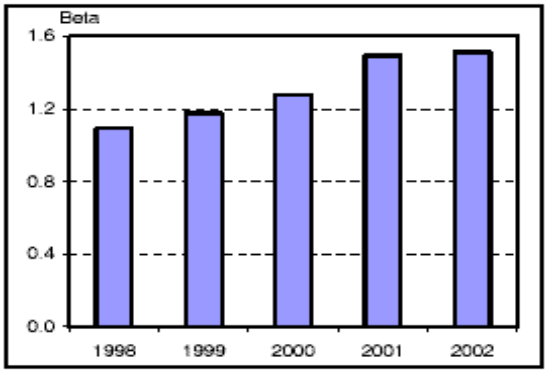
Under regulated utility regimes, both equity and debt investment returns are guaranteed by a cost recovery system over time. Thus, the risk for equity or debt holders is the same. However, the investment risk for equity holders is greater than that of debt holders under unregulated utility regimes, since the power producer faces greater uncertain outcomes due to input factors and out prices as well as returns.

Figure 10. Airline Year-Average Beta
(11/1997 through 10/2002)



Source: Compustat®

Figure 11. Telecommunication Year-Average Beta
(11/1997 through 10/2002)



Source: Compustat®

As a result, the risk and return assessment must be estimated for the equity holders.[8] Equity holders now face with not only business risk but also financial risk so that the cost of equity should include financial risk premium.[9]

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 lever 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.

[8] In an event of bankruptcy, Chapter 11, in general, the equity holder bears all the costs and is at risk of losing all of their investment.

[9] 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.

In addition to the benchmark industry equity beta, the utility industry composite equity beta is computed using the Hamada model, which combines the Capital Asset Pricing Model (CAPM) with the Modigliani-Miller (MM) after-tax model to obtain the cost of equity to a leveraged firm.[10] This model captures not only business risk but also financial risk for equity holders.

Adjustment for Greenhouse Gas intensive technologies

While developing input assumptions for AEO2010, it was clear there is much debate and uncertainty surrounding the potential for climate change legislation and how much it is affecting the decision making of new power plants. It appears that banks and regulators are adding implicit costs to greenhouse gas (GHG) intensive technologies, when evaluating new investment opportunities. Therefore, for the AEO2010 reference case it was decided to model this through an increase in the cost of capital for new coal plants without carbon capture and sequestration. For those plant types only, a 3 percentage point adder was 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.

Adjustment for Loan Guarantee Program

The American Recovery and Reinvestment Act of 2009 provided $6 billion to pay the costs of loan guarantees authorized by EPACT 2005. These are meant to stimulate the deployment of new conventional renewable technologies, along with other programs. To qualify, new projects must be under construction by September 30, 2011. This provision has been represented in AEO2010 by lowering the cost of capital by 2 percentage points for all eligible renewable projects brought on by 2015. The 2015 date, 4 years after the September 30, 2011, start of construction cutoff date, was chosen to allow for the construction period associated with most renewable generating technologies.

[10] Conceptually, equity holders face a certain amount of risk which 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 due to 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).

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 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 Electricity Capacity Planning Submodule determines the capacity needed in each year to meet demand; demand is determined in the demand modules, with seasonal and hourly demands determined in the Electricity Load and Demand Submodule. Emissions of nitrogen oxide (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 Electricity Finance and Pricing (EFP) Submodule. Fixed and variable O&M costs are assumed to decline over time, reflecting recent historical trends. Electricity prices are provided to the demand models to determine electricity demand.

The EFD dispatches the available generating capacity – including fossil-fueled, nuclear and renewable generators. Traditional cogeneration is determined in the demand models, and represented with a fixed vector to incorporate their 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 pre-specified 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 is used to model load-shifting and/or peak shaving from demand response programs such as smart meters.

The EFD includes compliance with environmental legislation, including the Clean Air Act Amendments of 1990 (CAAA) and the Clean Air Interstate Rule of 2005 (CAIR). The AEO2010 does not incorporate the Clean Air Mercury Rule of 2005 (CAMR), which was invalidated by a court decision. Some compliance options are determined within the ECP (addition of scrubbers or other retrofits), but the EFD does include a detailed representation of the coal supply to determine the best mix of fuels and coal types to meet the emission targets.

The 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 SO_2, NO_x, mercury and carbon dioxide. The primary use of the EFD, as a component of the EMM and NEMS, is to develop projections for the Energy Information Administration's *Annual Energy Outlook* 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 forecast horizon. Intermediate projections of SO_2 and mercury emissions are calculated (final values come from the CMM), as well as the projections for NO_x and carbon dioxide emissions.

The EFD represents the dispatch and trade decision at the regional level. These regions, referred to as NEMS electricity supply regions, are North American Electric Reliability Council (NERC) regions and subregions (Table 10 see also 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 gas supply regions, etc.). The interaction between the EFD and other modules of the NEMS and other regional issues, including the required transformations between different regional structures, are described later in this section.

Table 10. NEMS Electricity Supply Regions

NERC Region/ Subregion	Acronym
East Central Area Reliability Coordination Agreement	ECAR
Electric Reliability Council of Texas	ERCOT
Mid-Atlantic Area Council	MAAC
Mid-America Interconnected Network	MAIN
Mid-Continent Area Power Pool	MAPP
Northeast Power Coordinating Council/New England	NPCC/NE
Northeast Power Coordinating Council/New York	NPCC/NY
Southeastern Electric Reliability Council	SERC
Florida Reliability Coordinating Council	FL
Southwest Power Pool	SPP
Western Electric Coordinating Council/Northwest Power Pool Area	WECC/NWP
Western Electric Coordinating Council/ Rocky Mountain Area, Arizona, New Mexico, Southern Nevada	WECC/RA
Western Electric Coordinating Council/California	WECC/CA

The EFD only incorporates current regulatory strategies to comply with emissions limits that can be implemented during dispatching, i.e. fuel switching. Retrofitting units with pollution control equipment is represented in the ECP.

Another feature of the EFD is the ability to engage in interregional economy transactions. Utilities are allowed to purchase power from utilities in neighboring regions if it is economic to do so and transmission capacity is available. In a contiguous time slice simultaneous dispatch and trade occurs by dispatching 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. Information on how much excess electricity supply is available by season and time slice from each Canadian Province is provided from an input file.

Relationship to Other Modules

The EFD requires input data from exogenous sources, other modules of the NEMS, and other submodules of the Electricity Market Module. This section contains an overview of the data flows within the EFD. Figure 12 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 units to complete the dispatch decision. This information is obtained for existing units from various EIA and Federal Energy Regulatory Commission (FERC) survey forms. Cost and performance data for future generating units are provided to the Office of Integrated Analysis and Forecasting from discussions with various sources — industry, government and the National Laboratories[42]. Transmission constraints and trade relationships are also input to incorporate firm and economy trade. Firm trade contracts are culled from NERC's Electricity Supply and Demand Database. Transmission characteristics are from NERC and WECC summer and winter reliability assessments.

[42] See *Assumptions for the AEO2010* for specific technologies and sources.

Sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (HG), carbon dioxide (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 can be found in Appendix 4.B.

Nuclear fuel cost projections are calculated through offline analysis as described in Appendix 4.C. and read in as an exogenous input.

Inputs from Other Modules [43]

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 submodule prior to the dispatch decision.

The commercial and industrial demand modules represent traditional cogeneration and other electricity production at their facilities. The generation provided by these modules is converted to capacity (assuming a 100 percent capacity factor) and assumed to provide this fixed amount to meet load in the LP. 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 due to significant shifts in fuel use due to the dispatch decision, before entering another NEMS iteration. Because the electricity and coal markets are closely related, with coal the primary input fuel for electricity production and the primary source for emissions produced from electricity generation, the EFD includes a detailed representation of the coal supply curves contained in the CMM.

The Electricity Capacity Planning (ECP) submodule provides the annual available capacity to be used in the dispatch decision as well as the share of biomass co-firing that is allowed from coal fired plants. The ECP determines any penalty costs necessary to meet constraints on NO_x emissions, and this is passed to the EFD for use in dispatching decisions. The ECP also provides banking decisions for SO_2 and mercury allowances, which the EFD uses to adjust the annual emission target accordingly. Some policy cases include a Renewable Portfolio Standard (RPS), requiring a certain percentage of total sales or generation to come from renewable sources. If an RPS is in place, the ECP passes the credit price to the EFD, and the EFD simply adjusts the operating costs to include the buying or selling of credits. The RPS is not modeled explicitly in the EFD because the primary means to meet the target are building new capacity, which must be determined by the ECP.

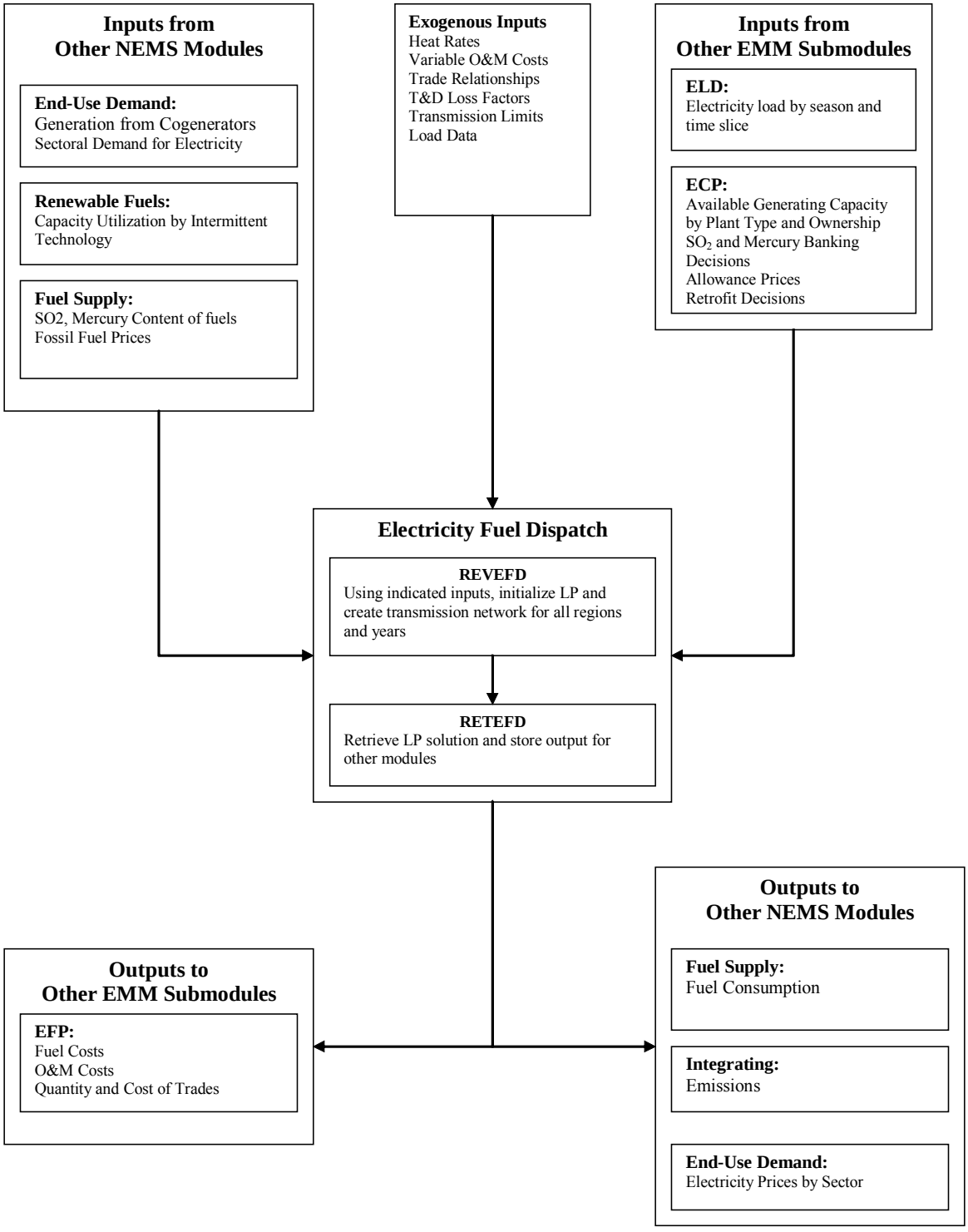
The EFD determines the allocation of generating capacity to meet electricity demand. The output of this decision is needed to determine the price of electricity and to account for: 1) the utilization of the fuel inputs; 2) renewable generation; and, 3) emissions. In particular, the EFP requires fuel 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"

[43] A synopsis of NEMS, the model components, and the interrelationships of the modules is presented in *The National Energy Modeling System: An Overview*. Detailed documentation of the modeling system and any of the modules is available in a series of documentation reports available on the A. CD-ROM. For ordering information, contact the National Energy Information Center (202/586-8800) or E-mail: infoctr@eia.doe.gov.

fuel use by all sectors. The EFD provides regional SO_2 and mercury removal rates to the CMM, and the final SO_2 and mercury emissions are computed in the CMM and passed to the integrating module. Emissions of NO_x are calculated in the EFD, based on NO_x emission rates determined by plant and boiler type.

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 for international economy trade. Reports include emissions. These reports contain both national and regional projections. National projections are published each year in the *Annual Energy Outlook* and regional projections are provided on EIA's Internet site (http://www.eia.doe.gov) in the *Supplement to the Annual Energy Outlook*.

Figure 12. EFD Data Inputs and Outputs



Model Rationale

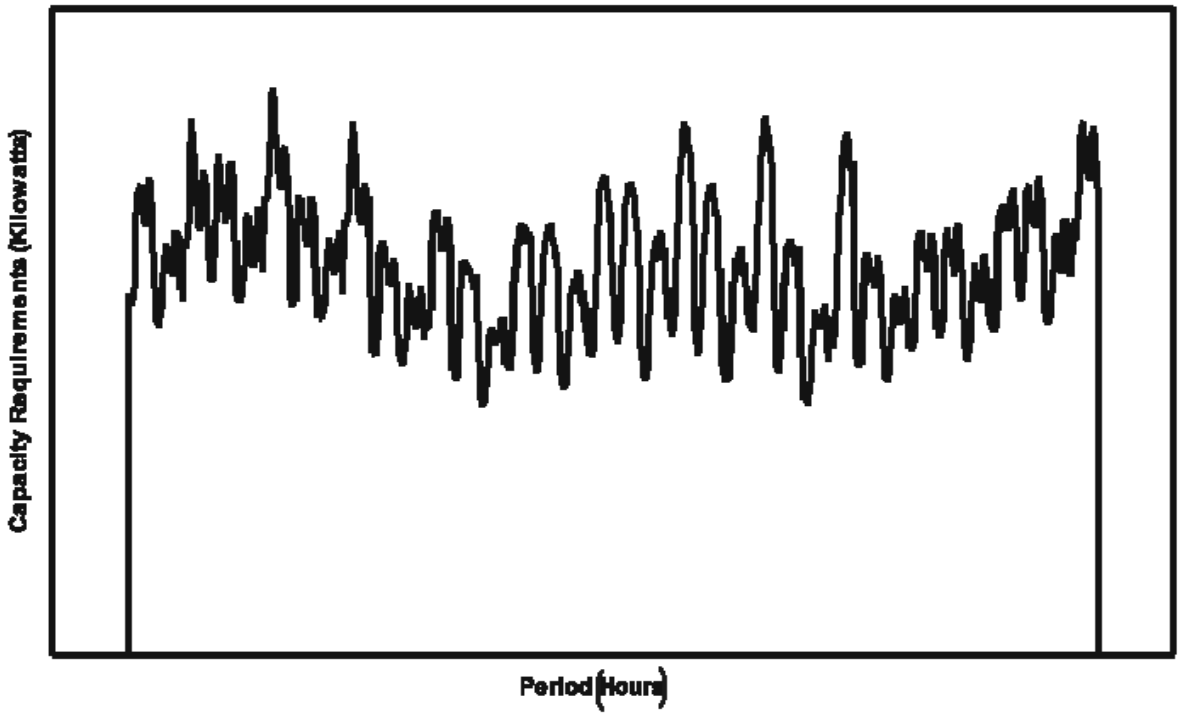
Theoretical Approach

Basic Model Approach. The EFD uses a linear programming (LP) approach to provide a minimum cost solution to allocating (dispatching) 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 the 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 on-line. 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. The 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). The AEO2010 includes the Clean Air Insterstate Rule (CAIR), which imposes stricter restrictions on SO_2 and NOx for some states. It also incorporates state-level removal standards for mercury.

Demand can be characterized by a load curve, which is a plot of power demand (load) versus time (Figure 13). 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 capacity assigned to satisfy demand at the base, or minimum point of the curve is required on a continuous basis. The percent of time capacity is required at each slice of load is called a capacity factor (utilization rate). The capacity factor for the load at the base of the curve is 100 percent and it approaches 0 percent at the peak of the load curve.

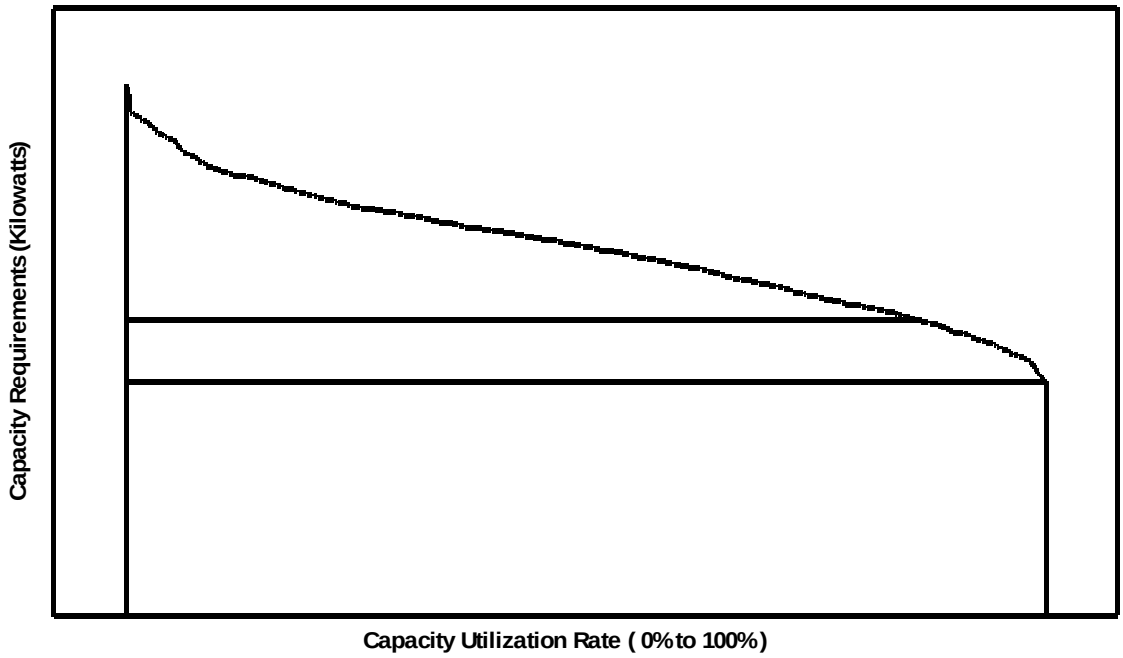
Figure 13. Typical Load Curve



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 14). 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 (e.g. 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 (in order 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, 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 14. Typical Load Duration Curve



The algorithm used for the dispatch decision is a straightforward LP formulation. It simulates the electric transmission network on the NERC region level and simultaneously dispatches 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 prior to the dispatch decision. Capacity costs for each time slice are based on fuel and variable O&M costs, making adjustments 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 (i.e., 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 Internet site, in the *Assumptions to the Annual Energy Outlook*. The Clean Air Act and its subsequent amendments contain Federal regulations for SO_2 and NO_x emissions by electric utilities. The most recent amendments to the CAA in 1990 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.

While 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 which 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 the EFD work together to ensure that emissions of sulfur dioxide do not exceed specified limits set by the Clean Air Act Amendments of 1990 (CAAA) and the Clean Air Interstate Rule (CAIR), and that mercury emissions meet the state-level 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 the EFD and CMM can more easily achieve convergence to the optimal coal consumption. Banking decisions for sulfur dioxide and mercury allowances are inputs to the EMM from the ECP.

The 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 13 electricity supply regions, the EFD also represents trading of emission allowances. That is, utilities with relatively low costs of reducing emissions may over comply (i.e. 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," i.e., is based only on a cost saving. However there are other factors involved in allowance trading which 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.

There are also assumptions regarding both the supply and demand for electricity in the 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 the expected value. Also, utilities in each of

the 13 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 3 points per season and region. Although this may not fully represent load variations, the aggregation is necessary due to computer time and resource constraints.

Model Structure

Introduction

The EFD is executed for each year and iteration of the model forecast to determine the amount of capacity dispatched, fuels used, electricity trade, and costs to meet the yearly level of demand. The EFD solves all load slices for the year simultaneously. 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.

The EFD prepares input data, solves the LP model, and provides the required outputs to the other submodules of the 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 LP model uses the Optimization and Modeling Library (OML) software, a proprietary mathematical programming package, to create and store coefficients in a database, solve the problem, and retrieve the solution. The OML subroutines are not documented in this report.[49]

Key Computations and Equations

This section provides the mathematical specification of the EFD. The 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 the EFD is to provide an economic and environmental dispatch and electricity trade procedure. In the LP optimization, the costs of generation, trade, and transmission are minimized for the entire United States. The decision variables include operating the generating units under different modes and fuel options and determining when to trade electricity. The

[49] For more information, see Ketron Management Science, Optimization and Modeling Library (Draft), (Arlington, VA, November 1992).

marginal source of electricity is selected for each time slice and reacts to changes in load.[50] The demand for electricity must also be satisfied without violating certain engineering and emissions restrictions. There are environmental, load-related, and capacity constraints placed on the dispatch decisions. The EFD integrates the least cost solution with environmental compliance and engineering constraints. Environmental issues incorporated into the NEMS include compliance with current SO_2, NO_x and mercury restrictions, as discussed above in "Assumptions."

The EFD forecasts domestic economy trade by including the option of "dispatching" (i.e. 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).[51] 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 are not allowed to 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(s) that corresponds 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 the EFD, but reported values are derived in the CMM. NO_x emissions are calculated in the 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.

Dimensions:

a = Activated Carbon Option
b = Fuel Region – Unique combination of Census, Coal and 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

[50] If load is increasing, then the cheapest available source of electricity is brought on-line. Similarly, if demand is decreasing, then the expensive source of electricity currently operating is shut down.

[51] Note that it is possible for electrical energy to flow in one direction during a season and in the opposite direction during another season.

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 Which Define Total Electricity Load
m = Mode of Operation (e.g., “Base,” “Intermediate,” “Peak”)
n = Renewable Capacity Type
p = Plant Group
q = Canadian Supply Step
r = Electricity Supply Region
s = Season
t = Distributed generation Technology Type (Base, Peak)
u = SO_2 Containment Area
v = NO_X 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

Decision Variables

BP_{Nd} = Quantity of Biomass Produced in Coal Demand Region N and Supply Step d (Trillion Btu)

BTU_{bB} = Fuel Consumption by Dedicated Biomass Plants B in Fuel Region b (Trillion Btu)

BTU_{bCf} = Fuel Consumption by Coal Plants C Under Fuel Option f in Fuel Region b (Trillion Btu)

BTU_{bDfj} = 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} = Fuel Consumption by Oil Plants D Under Fuel Option f in Fuel Region b (Trillion Btu)

$BTUE_N$ = Quantity of Biomass Fuel Used in for Ethanol Production in Coal Region N (Trillion Btu)

$BTUI_N$ = Quantity of Biomass Fuel Used in the Industrial Sector in Coal Region N (Trillion Btu)

CO_J = Other Coal (Nonutility) Demand Satisfied from Supply Curve J (Trillion Btu)

CP_{JM} = Quantity of Coal Produced from Supply Curve J and Supply Step M (Trillion Btu)

CT_{JNCa} = 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 = Mercury Emissions from Coal to Liquids Plants (Tons)

CTLSO2 = SO_2 Emissions from Coal to Liquids Plants (Thousand Tons)

$CTS2_{JN}$ = Quantity of Coal Transported at Additional Tier-2 Cost from Supply Curve J to Scrubbed Plants in Coal Demand Region N (Trillion Btu)

$CTU2_{JN}$ = 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 = Quantity of Distillate Fuel Oil Produced for Supply Step d (Trillion Btu)

DT_x = Quantity of Distillate Fuel Oil Transported to Oil Region x (Trillion Btu)

$ELNOX_c$ = NO_x emissions from Capacity Type c (Thousand Tons)

ESCNOX = Total NO_x emissions Incurring the NOx Penalty Cost from the ECP (Thousand Tons)

GP_d = Quantity of Natural Gas Produced for Supply Step d (Trillion Btu)

GT_{wj} = Quantity of Natural Gas Transported to Natural Gas Region w in Gas Season j (Trillion Btu)

MB_{ps} = Capacity Taken Out for Planned Maintenance for Plant Group p and Season s (Gigawatts)

$MERC_c$ = Mercury Emissions for Capacity Type c (Tons)

MP_{rcs} = Total Capacity Taken Out for Planned Maintenance for Region r, Capacity Type c and Season s (Gigawatts)

MVSO2 = SO_2 Emissions Traded From SO_2 Region to SO_2 Region (Thousand Tons)

$OPBS_{psm}$ = Use Baseload Plant Group p in Season s in Operating Mode m (Gigawatts)

$OPHY_{psl}$ = Use Hydro Plant Group p in Season s and Load Slice l (Gigawatts)

$OPIN_{ps}$ = Use Intermittent Plant Group p in Season s (Gigawatts)

$OPPK_{psl}$ = Use Peaking Plant Group p in Season s and Load Slice l (Gigawatts)

$OPRNW_{ps}$ = Use Renewable Plant Group p in Season s (Gigawatts)

$RELCP_{rs}$ = Set aside Capacity for Reliability Purposes in Region r and Season s (Gigawatts)

RLP_{rcs} = Set aside Capacity of Capacity Type c for Reliability Purposes, in Region r and Season s (Gigawatts)

RP_d = Quantity of Residual Fuel Oil Produced for Supply Step d (Trillion Btu)

RT_x = Quantity of Residual Fuel Oil Transported to Oil Region x (Trillion Btu)

STX_{rsl} = Storage Capacity Replaced in Region r, Season s and Load slice l (Million kwh)

$SULF_c$ = SO_2 Emissions by Capacity Type c (Thousand Tons)

$TRCN_{hqrsl}$ = Transfer Electricity from Canadian region h and Canadian Supply Step q to Region r in Season s and Load slice l (Gigawatts)

REL_{gesl} = Transfer Electricity from Import Region g to Export Region e in Season s and Load Slice l (Gigawatts)

TSTOCK = Net Change in Coal Stock (Trillion Btu)

Right-Hand Side Values

$CAPB_{ps}$ = Total Available Capacity for Baseload Plant Group p in Season s (Gigawatts)

$CAPP_{rcs}$ = Total Available Capacity for Peaking Capacity Type c in Region r and Season s (Gigawatts)

$CARLIM_{zy}$ = Carbon constraint in Containment Area z in year y (Million Metric Tons)

$CNAVL_{hqsl}$ = Available Canadian Power for Trading in Canadian Region h at Supply Step q in Season s and Load Slice l (Gigawatts)

$CONS_{JN}$ = Quantity of Coal Contracts for Coal Supply Region J to Scrubbed Plants in Coal Demand Region N (Trillion Btu)

$CONU_{JN}$ = Quantity of Coal Contracts for Coal Supply Region J to Unscrubbed Plants in Coal Demand Region N (Trillion Btu)

DVL_{NC} = Limit on Lignite Use in Coal Capacity Type C in Coal Demand Region N (Trillion Btu)

DVS_{NC} = Limit on Subbituminous Coal Use in Coal Capacity Type C in Coal Demand Region N (Trillion Btu)

EXP_{rs} = Maximum Transmission Capacity for Exports Allowed From Region r in Season s (Gigawatts)

$HGLIM$ = Mercury Constraint (tons)

$HYAVL_{ps}$ = Maximum Energy From Hydro Plant p in Season s (Million kwh)

IMP_{rs} = Maximum Transmission Capacity for Imports Allowed Into Region r in Season s (Gigawatts)

$LDREQ_{rsl}$ = Load requirement for Region r in Season s and Load Slice l (Million kwh)

$MRREQ_{rc}$ = Generation from Must Run Plants in Region r of Capacity Type c (Million kwh)

$PMBR_{p}$ = Planned Maintenance Requirement for Baseload Plant Group p (billion kwh)

$PMPR_{rc}$ = Planned Maintenance Requirements for All Capacity Type c in Region r (Million kwh)

$SO2LIM$ = SO2 constraint (Thousand Tons)

$TRAVL_{ghs}$ = Transmission Capacity Between Import Region g and Canadian Export Region h in Season s (Gigawatts)

$TS1_{JN}$ = Limit on Coal Transported from Coal Supply Region J to Scrubbed Plants in Coal Demand Region N at Tier-one Rates (Trillion Btu)

$TU1_{JN}$ = Limit on Coal Transported from Coal Supply Region J to Unscrubbed Plants in Coal Demand Region N at Tier-one Rates (Trillion Btu)

Coefficients

$BREQ_{psl}$ = Consumption requirement per unit of capacity for Peaking Plant Group p Operating in Season s and Load Slice l (Trillion Btu/GW)

$BREQ_{psm}$ = Consumption requirement per unit of capacity for Baseload Plant Group p Operating in Season s and Operating Mode m (Trillion Btu/GW)

$BREQ_{ps}$ = Consumption requirement per unit of capacity for Renewable Plant Group p Operating in Season s (Trillion Btu/GW)

$CARC_{bCf}$ = Average Carbon Content for Coal Capacity Type C Under Fuel Option f in Fuel Region b (Million Metric Tons per Trillion Btu)

$CARD_{bDf}$ = 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)

$CARO_{bDf}$ = Average Carbon Content for Oil-Fired Capacity Type D Under Fuel Option f in Fuel Region b (Million Metric Tons per Trillion Btu)

CBP_{Nd} = Production Cost of Biomass for Coal Demand Region N and Supply Step d (Dollars per Million Btu)

CCP_{JM} = Production Cost of Coal for Supply Curve J and Supply Step M (Dollars per Million Btu)

CCT_{JNCa} = Tier-One 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)

$CCT2_{JN}$ = Incremental Tier-Two Transportation Cost for Coal Delivered from Supply Curve J to Coal Demand Region N (Dollars per Million Btu)

CDP_d = Production Cost of Distillate Fuel Oil for Supply Step d (Dollars per Million Btu)

CDT_x = Transportation Cost for Distillate Fuel Oil Delivered to Oil Region x (Dollars per Million Btu)

CGP_d = Production Cost of Natural Gas for Supply Step d (Dollars per Million Btu)

CGT_{wj} = Transportation cost for Natural Gas Delivered to Gas Region w in Gas Season j (Dollars per Million Btu)

$CLSHR_{bCf}$ = Coal Share For Operating Capacity Type C in Fuel Region b and Fuel Option f (Fraction)

COF_{NC} = Cofiring Share for Coal Capacity Type C in Coal Demand Region N (Fraction)

CRP_d = Production Cost of Residual Fuel Oil for Supply Step d (Dollars per Million Btu)

CRT_x = Transportation Cost for Residual Fuel Oil Delivered to Oil Region x (Dollars per Million Btu)

$CSTBS_{psm}$ = Variable Operating Cost for Baseload Plant Group p in Season s and Operating Mode m (Million Dollars per Gigawatt)

$CSTCN_{hq}$ = Cost of Canadian Power available from Canadian Region h and Supply Step q (Million Dollars per Gigawatt)

$CSTHY_{psl}$ = Variable Operating Cost for Hydro Plant Group p in Season s and Load Slice l (Million Dollars per Gigawatt)

$CSTIN_{psl}$ = Variable Operating Cost for Intermittent Plant Group p in Season s and Load Slice l (Million Dollars per Gigawatt)

$CSTPK_{psl}$ = Variable Operating Cost for Peaking Plant Group p in Season s and Load Slice l (Million Dollars per Gigawatt)

$CSTRNW_{ps}$ = Variable Operating Cost for Baseload Renewable Plant Group p in Season s (Million Dollars per Gigawatt)

$CSTTR_{ge}$ = Incremental Cost to Trade Power From Import Region g to Export Region e (Million Dollars per Gigawatt)

$DSSHR_{bDf}$ = Distillate Share For Operating Capacity Type D in Fuel Region b and Fuel Option f (Fraction)

GEN_{psm} = Generation Output from Plant Group p Used in Operating Mode M in Season s (Hours)

GEN_{psl} = Generation Output from Plant Group p Used in season s and Load Slice l (Hours)

GEN_{ps} = Generation Output from Plant Group p Used in Season s (Hours)

HGC_{JbC} = Average Mercury Content of Coal Plant Type C Using Coal Supply Curve J in Fuel Region b (Tons per Trillion Btu)

$HOURS_s$ = Hours in Season s

$HRFAC_{sl}$ = Fraction of Total Seasonal Hours for Load Slice l and Season s

$NGSHR_{bDf}$ = Natural Gas Share For Capacity Type D in Fuel Region b and Fuel Option f (Fraction)

$NOXC_p$ = Average NO_x content of Plant Group p (Pounds per Million Btu)

NOXPv = NO_x Allowance Price from ECP for NO_x Region v (Dollars per Ton)

$RSSHR_{bDf}$ = Residual Fuel Share For Operating Capacity Type D in Fuel Region b and Fuel Option f (Fraction)

$SO2C_{JbC}$ = Average SO2 Content for Coal Capacity Type C Using Coal Supply Curve C in Fuel Region b (Pounds per Million Btu)

$STFAC_i$ = Generation Replacement Factor for Storage Technology type i (Fraction)

TLOSS = Transmission Losses Incurred Between Regions (Percent)

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:

- Production costs for coal, natural gas, oil and biomass
- 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 baseload dispatchable capacity

- Operation costs of peak 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 NO_x emission controls

(4-1)

$$
\begin{aligned}
&MIN \\
&\sum_{J}\sum_{M} CCP_{JM} \cdot CP_{JM} + \sum_{J}\sum_{N}\sum_{C}\sum_{a} CCT_{JNCa} \cdot CT_{JNCa} + \\
&\sum_{J}\sum_{N} CCT2_{JN} \cdot CTS2_{JN} + \sum_{J}\sum_{N} CCT2_{JN} \cdot CTU2_{JN} + \\
&\sum_{d} CGP_{d} \cdot GP_{d} + \sum_{w}\sum_{j} CGT_{wj} \cdot GT_{wj} + \sum_{d} CDP_{d} \cdot DP_{d} + \sum_{x} CDT_{x} \cdot DT_{x} + \\
&\sum_{d} CRP_{d} \cdot RP_{d} + \sum_{x} CRT_{x} \cdot RT_{x} + \sum_{N}\sum_{d} CBP_{Nd} \cdot BP_{Nd} + \\
&\sum_{p}\sum_{s}\sum_{m} CSTBS_{psm} \cdot OPBS_{psm} + \sum_{p}\sum_{s}\sum_{l} CSTPK_{psl} \cdot OPPK_{psl} + \sum_{p}\sum_{s}\sum_{l} CSTHY_{psl} \cdot OPHY_{psl} + \\
&\sum_{p}\sum_{s}\sum_{l} CSTIN_{psl} \cdot OPIN_{psl} + \sum_{p}\sum_{s} CSTRNW_{ps} \cdot OPRNW_{ps} + \sum_{p}\sum_{s}\sum_{m} CSTDG_{psm} \cdot OPDG_{psm} + \\
&\sum_{g}\sum_{e}\sum_{s}\sum_{l} CSTTR_{ge} \cdot TREL_{gesl} + \sum_{g}\sum_{h}\sum_{q}\sum_{s}\sum_{l} CSTCN_{hq} \cdot TRCN_{ghqsl} + \\
&\sum_{v} NOXP_{v} \cdot ESCNOX_{v}
\end{aligned}
$$

Description of Constraints

Coal Submatrix. The 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 the Coal Market Module (CMM) and are also similar to the representation of coal supply in the ECP. The EFD makes decisions for generation and fuel consumption, subject to emissions limits, in this representation. Since coal plants can also be modified to cofire with biomass fuels, decisions to retrofit existing capacity to allow cofiring are also included in this structure. The resulting coal demands are then passed to the CMM.

The EFD utilizes the same two-tier pricing system for transportation costs that is incorporated in the 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 able to be transported for use by generators in multiple electricity regions. Similarly, coal 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:

$$\sum_{N} \sum_{C} \sum_{a} CT_{JNCa} - CO_{J} - \sum_{M} CP_{JM} \leq 0 \qquad (4\text{-}2)$$

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:

$$\sum_{F} \sum_{a} CT_{JNFa} \geq CONU_{JN} \qquad (4\text{-}3)$$

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 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 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:

$$\sum_{K} \sum_{a} CT_{KNCa} \leq DVS_{NC} \qquad (4\text{-}4)$$

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 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 first tier rates assume that the current rates are limited to historical flow levels. In order to deliver additional supplies, an incremental cost (second tier rate) is incurred. The constraints on first-tier rates are imposed for unscrubbed capacity types F as follows:

$$\sum_{F}\sum_{a} CT_{JNFa} - CTU2_{JN} \le TU1_{JN} \quad \text{(4-5)}$$

for every supply curve J in coal region N.

The quantity $TU1_{JN}$ represents the limit on coal that can be transported at tier one rates from coal supply curve J to unscrubbed plants in coal demand region N. Thus, the equation insures 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-two rates ($CTU2_{JN}$) does not exceed the limit delivered at tier-one 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-two rates ($CTS2_{JN}$), and the corresponding limit on tier-one 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. The transportation variables (GT_{wj}) describe the delivery of natural gas to generating plants in gas region w and gas season s. This row is defined as follows:

$$\sum_{w}\sum_{j} GT_{wj} - \sum_{d} GP_{d} \le 0 \quad \text{(4-6)}$$

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:

$$\sum_{x} RT_{x} - \sum_{d} RP_{d} \le 0 \quad \text{(4-7)}$$

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

(4-8) $$\sum_{x} DT_x - \sum_{d} DP_d \leq 0$$

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 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_{bBf}). Biomass fuel used for cofiring in coal fired plants is the product of the fuel used in coal 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_{NM}). As a result, the supply curves are specified for each of the coal regions, as follows:

(4-9) $$\sum_{b \in N} BTU_{bBf} + \sum_{b \in N} \sum_{C} COF_{NC} \bullet BTU_{bCf} + BTUE_N + BTUI_N - \sum_{d} BP_{Nd} \leq 0$$

for each coal region N.

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 consumption. There are sets of constraints for each fossil fuel and for biomass fuel.

Coal:

(4-10) $$-\sum_{J} \sum_{a} CTL_{JbCa} + \sum_{f} CLSHR_{bCf} \cdot BTU_{bCf} \leq 0$$

for every fuel region, b, and coal plant type, C. The fuel share options, f, provide for different fuel options for the plant. For coal plants this would primarily reflect cofiring with biomass. For the Annual Energy Outlook 2006, the EFD was set up to use the ECP solution for cofiring levels, so there was only one fuel option for coal plants in this equation. However, the EFD is set up to solve for cofiring decisions within the LP.

Natural Gas:

$$(4\text{-}11) \quad -GT_{wj} + \sum_{b \in w} \sum_{D} \sum_{f} MGSHR_{bDf} \cdot BTU_{bDfj} \leq 0$$

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 gas use by the given plant type. Because gas prices vary by season (summer/winter) 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.

Distillate:

$$(4\text{-}12) \quad -DT_{x} + \sum_{b \in x} \sum_{D} \sum_{f} DSSHR_{bDf} \cdot BTU_{bDf} \leq 0$$

Residual Fuel:

$$(4\text{-}13) \quad -RT_{x} + \sum_{b \in x} \sum_{D} \sum_{f} RSSHR_{bDf} \cdot BTU_{bDf} \leq 0$$

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 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, such as coal, nuclear and combined cycle, are allowed to run in certain modes. These plant types cannot be brought up and down quickly, so should not be dispatched by each time slice independently. Instead, there are a minimum number of slices they must run to be considered economic, defined by the assumed minimum capacity factor.

Coal plant types:

$$(4\text{-}14) \quad -\sum_{f} BTU_{bCf} + \sum_{p} \sum_{s} \sum_{m} BREQ_{psm} \cdot OPBS_{psm} \leq 0$$

for every fuel region b and coal plant type C, and where plant group p is in fuel region b and of coal 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. It is calculated in the model by multiplying the derating factor by the hours of operation (based on the mode of operation) and the heatrate of the plant. The derating factor adjusts the output for the forced outage rate and load following.

Natural Gas and Oil fired plant types:

Baseload/intermediate types (combined cycle):

$$(4\text{-}15) \quad -\sum_{f} BTU_{bDfj} + \sum_{p} \sum_{s} \sum_{m} BREQ_{psm} \; OPBS_{psm} \leq 0$$

Peak types (combustion turbines, oil/gas steam):

$$(4\text{-}16) \quad -\sum_{f} BTU_{bDfj} + \sum_{p} \sum_{s} \sum_{l} BREQ_{psl} \; OPPK_{psl} \leq 0$$

for every fuel region b, plant type D that uses oil and/or natural gas, and natural gas season j, and where plant group p is in fuel region b and of plant type D. The fuel consumption required for the baseload/intermediate capacity is calculated as for coal plants. For the peak capacity types, each slice is dispatched independently, and the fuel consumption is simply the derate factor multiplied by the hours in the time slice and by the heatrate of the plant.

Biomass plants:

$$(4\text{-}17) \quad -BTU_{bB} + \sum_{p} \sum_{s} BREQ_{ps} \; OPRNW_{ps} \leq 0$$

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. Dispatchable renewable capacity is assumed to run at its maximum capacity factor within a season, and not given a choice of modes. The fuel consumption required ($BREQ_{ps}$) is calculated by the maximum capacity factor multiplied by the hours in the season, and by the heatrate of the plant.

Nuclear plants:

$$(4\text{-}18) \quad -BTU_{c} + \sum_{p} \sum_{s} \sum_{m} BREQ_{psm} \; OPBS_{psm} \leq 0$$

for all plant groups p that are nuclear capacity types. Nuclear plants are dispatched in the same manner as coal 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 (i.e., 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. Peaking capacity types are assumed to be able to be dispatched in each load slice independently, and do not have limited operating modes. 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, or $OPPK_{psl}$) and the hours in the load slice.

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. The capacity is operated at the average capacity factor uniformly over all the load segments. The contribution to load is the product of the capacity ($OPRNW_{ps}$) 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. Generating capacity with intermittent energy sources can be used to satisfy energy requirements in those load segments for which input energy is fully or partially available. For example, solar capacity can be used during those load segments in which the sun is shining. Their contribution is the product of the capacity ($OPINT_{psl}$), the capacity factor for the time slice and the hours in the time slice. Finally, load can be met by trade from surrounding regions, including Canadian regions.

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 is a negative contribution to the load requirement, effectively increasing the demand.

$$\begin{aligned}(4\text{-}19)\quad & \sum_{p} \mathbf{GEN_{psm}} \cdot \mathbf{OPBS_{psm}} + \sum_{p} \mathbf{GEN_{psl}} \cdot \mathbf{OPPK_{psl}} + \sum_{p} \mathbf{GEN_{psl}} \cdot \mathbf{OPRNW_{ps}} \\ & + \sum_{p} \mathbf{GEN_{psl}} \cdot \mathbf{OPIN_{psl}} + \sum_{p} \mathbf{GEN_{psl}} \cdot \mathbf{OPHY_{psl}} + \sum_{p} \mathbf{GEN_{psm}} \ \mathbf{OPDG_{psm}} - \mathbf{STX_{rsl}} \\ & + \sum_{e<>r} (1 - \mathbf{TLOSS}) \cdot \mathbf{TREL_{resl}} - \sum_{g<>r} \mathbf{TREL_{rgsl}} + \sum_{h} \sum_{q} \mathbf{TRCN_{hqrsl}} \leq \mathbf{LDREQ_{rsl}}\end{aligned}$$

for every region r, season s and 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 is 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.

$$(4\text{-}20)\quad \sum_{l} GEN_{psl} \ OPHY_{psl} \leq HYAVL_{ps}$$

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 1.36, requiring 36% 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. For AEO2010, the demand storage factor was set to 0.96, assuming a small amount of peak shaving, but keeping overall demand fairly constant.

$$\sum_{p}\sum_{l} \mathbf{OPHY_{psl} \bullet STFAC_i \bullet GEN_{psl} - \sum_{l} STX_{yrsl} \leq 0} \quad (4\text{-}21)$$

for all pumped storage or demand storage plants p, in EMM region r, for each season s.

Interregional Trade Constraints Total imports and exports to/from each region are imposed through these constraints. In AEO2006 the limit on total imports/exports is set to 75% of the maximum import/export capability to the region.

$$\sum_{g} TREL_{grsl} \leq EXP_{rs} \quad (4\text{-}22)$$

$$\sum_{e} TREL_{resl} \leq IMP_{rs} \quad (4\text{-}23)$$

for every region r, 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 The EFD includes a supply curve of available capacity from the Canadian NERC 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.

$$\sum_{g} TRCN_{ghqsl} \leq CNAVL_{hqsl} \quad (4\text{-}24)$$

for every Canadian region h, supply step q, season s and load slice l.

Total imports between any Canadian region and EMM region is also constrained by the transmission capability available.

$$\sum_{q} TRCN_{ghqsl} \leq TRAVL_{ghs} \quad (4\text{-}25)$$

for every import region g, 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 or technology type satisfies the annual maintenance requirements. For baseload capacity these constraints are modeled at the plant

group level – that is, each plant is scheduled individually. For these units, which typically run at maximum capacity factor, it is important 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. The modeler can choose through input file switches the maintenance method for each technology type. For AEO2006, coal, combined cycle and nuclear plants used the individual plant method for maintenance scheduling, as follows:

$$(4\text{-}26) \quad \sum_s HOURS_s \cdot MB_{ps} \geq PMBR_p$$

for every plant group p, where $HOURS_s$ is the number of hours in the season s.

For other dispatchable capacity types, planned maintenance requirements are imposed by region and plant type.

$$(4\text{-}27) \quad \sum_s HOURS_s \cdot MP_{rcs} \geq PMPR_{rc}$$

for every technology type c and region r.

Capacity Balance Requirements The capacity balance constraints ensure that, for each plant group or plant type, 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, for those plant types scheduling maintenance for each plant individually, while other dispatchable types would have a constraint for the region and plant type.

Coal, Nuclear and Combined Cycle:

$$(4\text{-}28) \quad MB_{ps} + \sum_m OPBS_{pms} \leq CAPB_{ps}$$

for every plant group p and season s.

Other capacity (primarily peaking capacity):

$$(4\text{-}29) \quad MP_{rcs} + \sum_{p \in c} \sum_l HRFAC_{sl} \cdot OPPK_{pmsl} + RLP_{rcs} \leq CAPP_{rcs}$$

for every region r, capacity type c and season s. The coefficient $HRFAC_{sl}$ represents the share of hours in each load slice relative to the total hours in the season. The term RLP_{rcs} is meant to capture reliability issues, and gives the model incentive to maintain a certain level of reserve capacity, which affects the marginal cost pricing in the next chapter.

Reliability Balance For plant types that have a reliability term in the capacity balance row, there is an additional constraint to balance this reliability component. The constraint limits the amount of capacity that can be set aside for reliability purposes.

$$(4\text{-}30) \quad RELCP_{rs} - \sum_c RLP_{rcs} \leq 0$$

for every region r, capacity type c and season s. The term $RELCP_{rs}$ is a decision variable that is given a minimal negative value in the objective function, and serves as the incentive for the LP to choose this option to set aside some reserve capacity. A limited share (set by the modeler) of the peak capacity requirement for the season (set by the modeler) is the bound for this variable.

"Must run" Constraints Certain plants are considered "must run", which means they will operate regardless of their operating costs. These are plants that are typically uneconomic when evaluated by the model, but based on historical data are consistently being put to use. Their operation could be relieving transmission congestion that is not captured in the EMM, or be based on fixed contracts. The EFD attempts to capture this generation in an attempt to maintain historical patterns throughout the forecast. There are some cases (carbon constrained, for example) where 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. The constraint takes one of two forms, depending on whether the plant group type is modeled as baseload or peaking.

Baseload:

$$\sum_{s} \sum_{m} GEN_{psm} \cdot OPBS_{psm} \geq MRREQ_{p} \quad (4\text{-}31)$$

for every plant group p.

Peaking:

$$\sum_{s} \sum_{l} GEN_{psl} \cdot OPPK_{psl} \geq MRREQ_{p} \quad (4\text{-}32)$$

for every plant group p.

Emissions constraints These constraints limit the emissions produced as a result of electricity generation. Emissions from SO_2 and mercury depend on the type of coal being used, as well as the configuration of the plant and amount of electricity produces. These emissions are constrained explicitly in the EFD based on the SO_2 content (SO2C) 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. The ECP has already made the retrofit decisions necessary to meet the goals, so the EFD does not explicitly constrain the NO_x emissions. Instead there is a row accumulating the NO_x emissions and balancing it with a vector that incurs the cost of the NO_x penalty as determined by the ECP. In this way the EFD passes the costs of compliance along to the EFD, and this does restrict the emissions to roughly the levels required.

The Clean Air Interstate Rule (CAIR) limits SO_2 and NO_x emissions from 28 states. The other states would still be subject to the CAAA90 Title IV requirements. Allowances banked under the old program can be used before 2010 to meet CAIR, but after 2010 the old allowances are not worth 100% of their original value. The emissions limit for a given year is adjusted to represent additions or withdrawals from the bank. Regional targets can be met by reducing emissions within the region, or trading allowances from the other SO_2 region.

Regional sulfur constraint:

(4-33)

$$\sum_{N \in u1} \sum_{J} CTLSO2_{JN} + \sum_{c} SULF_{cu1} + MVSO2_{u2u1} - MVSO2_{u2u1} - AVGSO2 \cdot TSTOCK \leq SO2LIM_{y} + BNK_{y-1} - B$$

for every sulfur region u. The terms MVSO2 represent trading SO_2 allowances between the two sulfur regions. The term TSTOCK represents the amount of coal set aside for inventory, and therefore not being used or producing emissions. The term $SULF_{cu}$ simply accumulates the emissions by plant type in a separate balancing constraint, to limit the size of the constraint and make the model easier to solve.

(4-34) $$-SULF_{Cu} + \sum_{J} \sum_{b \in u} SO2C_{JbC} \cdot CT_{JbC} \leq 0$$

for every coal plant type, C and sulfur region u. The use of activated carbon only affects mercury emissions so it is not reflected in the SO_2 emissions coefficient. There is a similar constraint to account for the sulfur from residual fuel.

Mercury emissions are modeled in a similar manner. An additional difference is that mercury in coal plants can also be reduced by injecting activated carbon. but there is only a national constraint each year. Without CAMR, there isn't a national limit on mercury ($HGLIM_y$) so the following equation also just accumulates mercury emissions..

National mercury constraint:

(4-35) $$\sum_{N} \sum_{J} CTLHG_{JN} + \sum_{C} MERC_{C} - AVGHG \cdot TSTOCK \leq HGLIM_{y} - BNKHG_{y}$$

Plant type balancing row:

(4-36) $$-MERC_{C} + \sum_{J} \sum_{b} \sum_{a} HGC_{JbC} \cdot CT_{JbCa} \leq 0$$

As discussed above, the NO_x emissions are dependent on the plant type but not the specific coal used. The EFD cannot make retrofit decisions, so 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 so that it is included in the marginal cost of electricity generation.

Regional NO_x constraint:

(4-37) $$\sum_{c} ELNOX_{cv} - ESCNOX_{v} \leq 0$$

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.

Plant type balancing row

Baseload plants:

(4-38) $$-ELNOX_{cv} + \sum_{p \in v} \sum_{s} \sum_{m} NOXC_{p} \cdot BTUREQ_{psm} \; OPBS_{psm} \leq 0$$

for every capacity type c that is modeled as baseload capacity and every NO_x region v.

Peaking plants:

(4-39) $$-ELNOX_{cv} + \sum_{p \in v} \sum_{s} \sum_{l} NOXC_{p} \cdot BTUREQ_{psl} \; OPPK_{psl} \leq 0$$

for every capacity type c that is modeled as peaking capacity, and every NO_x region v.

Carbon emissions are not regulated at the federal level, but the Regional Greenhouse Gas Initiative (RGGI) does specify limits ($CARLIM_{zy}$) for a collection of states.

Regional carbon constraint:

(4-40) $$\sum_{b \in z} \sum_{C} \sum_{f} CARC_{bCf} \cdot BTU_{bCf} + \sum_{b \in z} \sum_{D} \sum_{f} \sum_{j} CARD_{bDf} \cdot BTU_{bDfj} + \sum_{b \in z} \sum_{D} \sum_{f} CARO_{bDf} \; BTU_{bDf} \leq CARLIM_{zy}$$

for every carbon containment region z in year y. The first term of the equation represents the carbon emissions from coal 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.

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Appendix 4.A EFD Data Flows

The EFD runs every year and iteration of the NEMS, as long as the EMM model is selected to be run. The EMM often makes use of direct access files (DAFs) to store data that is passed back and forth between submodules, or 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. 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. *ELEFD* next calls *EFDOML*, which creates or revises the LP matrix, solves the LP and retrieves the solutions, making use of OML subroutines for the LP management. Fuel consumption, generation and emissions are accumulated during the solution retrieval subroutine. *ELEFD* then calls subroutine *ELRPSCR*, where the costs of renewable credits for each region are calculated when there is a renewable portfolio standard in place. The final subroutine call is simply to create reports used in analysis. The remainder of this section will go into more detail in each of the major subroutines.

The EFD begins by reading information on firm trades and the transmission constraints for economy interregional trade. The height 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, but is still useful to create an ordered list of plants and the sorted group numbers are used elsewhere in the model for storing results. Before determining the merit order, 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.

Once *ELDISP* is completed, the model calls the subroutine to process the LP, *EFDOML*. This subroutine sets the various parameters to initialize the LP database. It then calls the subroutine *REVEFD*, which actually sets the coefficients and constraints. This is done through a series of subroutines to address each section of the model.

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 put in the objective function.

ED$TRADE sets up the transmission network to allow for 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. Additional structure is created to encourage the outages to occur during the season with the most free time, thereby balancing the amount of capacity available for reliability purposes (which is important for competitive pricing).

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 nonutilties and cogenerators. The contribution from traditional cogenerators is represented with a fixed vector based on the levels provided from the demand models.

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*, *OPPEAK*, *OPRNBS*, *OPHYD*, or *OPINT*. *OPBSLD* is used for baseload type fossil 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 which is not appropriate for these plant types. *OPPEAK* is used for peaking fossil plants, and creates independent operate vectors for each time slice. *OPRNBS* is used for renewable plants that operate in a baseload manned, such as biomass and geothermal. These plants have only one option per season, operating at their capacity factor for each slice in the season. *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. Finally, *OPINT* is used for intermittent technologies, where the potential output for each time slice is based on varying capacity factors due to different availabilities based on time of day.

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 characteristic such as Btu content and emissions rates for SO_2, NOx, mercury, and carbon dioxide. It also sets up the coal and mercury emission constraints.

ED$GAS sets up the natural gas supply curves, in the same fashion as used in the ECP.

ED$OIL sets up the oil supply curves, again using the same methodology as in the ECP.

ED$BIO sets up the biomass fuel supply curves, using the exogenous supply steps from the RFM. Other uses of biomass such as ethanol and industrial use are accounted for, since they all must come from the same supply.

The subroutine *EFDOML* then executes several OML routines to process the data, load the matrix, and solve the model. *EFDOML* then calls a series of subroutines to obtain solution values that are provided to other components of the EMM.

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$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. 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 renewable information.

Once the model returns from the *EFDOML* subroutine, *ELRPSCR* is called to do the renewable credit trading. This is only necessary when a renewable portfolio standard (RPS) is in place, which 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 EFD. Each data source is accompanied by a brief description.

Survey Forms

Form EIA-860

The Form EIA-860 is a mandatory census of electric generators that operate power plants or plan to operate a power plant within five years of the reporting year. Separate surveys collect data from both utilities (EIA-860A) and nonutilities (EIA-860B). The survey collects data on existing power plants, and on five year plans for constructing new plants, and modifying and retiring existing plants. Data is collected at the generating unit level and includes capacity and fuel source information, along with ownership and location data.

Form EIA-767

The Form EIA-767 is a mandatory census of all steam-electric power plants with generating capacity of 100 megawatts or greater. A subset of the data is provided from plants with capacity between 10 and 100 megawatts. The form is used to collect data annually on plant operations and equipment design (including boiler, generator, cooling system, flue gas desulfurization, flue gas particulate collectors, and stack data). This data is used to calculate capacity factors and heatrates for existing steam units for use in the EFD.

Form EIA-906

Form EIA-906 collects information from regulated and unregulated electric power plants in the United States. Data collected include electric power generation, energy source consumption, end of reporting period fossil fuel stocks, and useful thermal output from cogenerators. 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 of the electric power industry and to evaluate the future of the industry. Form EIA-906 monthly respondents are a representative sample of electric power plants by State and by energy source. Electric power plants that do not report data monthly submit data annually.

Form EIA-920

Form EIA-920 collects information from combined heat and power plants with a generating capacity of 1 megawatt (1000 kW) and above in the United States. Data collected include electric power generation, fuel consumption, fuel heat content, and fossil fuel stocks. These data are used to monitor the current status and trends of electric power generation facilities. 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 of the electric power industry. Form EIA-920 monthly respondents are a representative sample of combined heat and power plants with a generating capacity of 1 megawatt (1000 kW) and above by State and by energy source. Combined heat and power plants that do not report data monthly submit data annually.

Form EIA-412

The Form EIA-412 is designed to collect accounting, financial and operating data from publicly-owned electric power entities. Data collected include balance sheets, income statements, sales of electricity for resale, electric operations and maintenance expenses, purchase power and power exchanges. The average historical operations and maintenance expenses are calculated by plant, and used in the EFD as part of the calculation of total operating costs.

FERC Form 1

The 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.

Environmental Protection Agency - Emissions Monitoring

The 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 is 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 be calculated for each plant for use in the EFD.

North American Electric Reliability Council - Transmission and Trade Data

Electricity Supply and Demand Database

The NERC ES&D database collects annual data and ten year projections of electricity demand, generating and transmission capacity, and capacity purchases and sales, by NERC region, and in some cases, by utility. The historical and projected interregional trade contracts are used as input to the EFD to capture firm power transactions.

Reliability Assessment Reports

NERC publishes summer and winter reliability assessment reports each year, to assess expected demand and available resources to meet demand, as well as to address transmission reliability issues. The report includes details on interregional transmission capability, which is used as input to the EFD to limit interregional trade to what can be transferred across existing lines.

Appendix 4.C. Nuclear Fuel Cost Projections

Nuclear fuel prices are calculated through an offline analysis which determines the cost in mills/kWh. The final cost is the sum of the 4 processes needed to produce reactor grade uranium: mining, conversion, enrichment, and fabrication. A one mill per kilowatthour waste fee is also added to account for the required payment into DOE's long-term waste fund. At each stage of the process, the energy produced per unit mass of fuel is multiplied by the cost of the fuel or service, giving an answer consistent with the mills/kWh units. All prices come from Energy Resources International. Only the once through fuel cycle is assumed in NEMS.

- The once through nuclear fuel production process begins with the mining of uranium (lbs U308). This uranium is then sent through a conversion process where it is gasified into UF-6 which prepares it for enrichment. The potential fuel is then enriched to a given purity of U-235 that can be used in a reactor. For commercial reactors in the United States, this purity is in the range of 3-5%. The final step in this process is fabrication, where enriched uranium is prepared for use in a specific type of reactor core.
- The mass product of uranium after the mining and conversion stage is calculated using the feed to product ratio. This measures a ratio between the differences in uranium concentration of enriched uranium and tail assays divided by the difference between natural uranium concentration and tail assays (equation 1). The enrichment of natural uranium is assumed to be 0.711%, while average value of enriched fuel is approximately 4.55%. The enrichment of tails is assumed to be the lowest cost option between 0.2% and 0.3%. These similar assumptions are also used to calculate the SWU/product ratio.
    - Equation 1: (Product-Tails)/(Natural U-Tails)
- The power output per mass unit of uranium is based off of the assumed amount of energy produced in the reactor per unit mass of fuel, referred to as fuel burnup. Two sets of fuel burnup assumptions are used, one for pressurized water reactors and the other for boiling water reactors. The assumptions are shown in Table 11.

Table 11. Nuclear Fuel Burnup Assumptions

	Pressurized Water Reactor		
	Burnup Rate (MWD/ MTIHM)	Fresh Fuel Assay (% U-235)	Cycle Length (Months)
2010-2015	50,000	4.54%	19.40
2016-2020	51,200	4.73%	20.34
2021-2025	52,000	4.73%	20.34
2026-2030	52,000	4.84%	20.34
2035	52,000	4.84%	20.34
	Boiling Water Reactor		
2010-2015	50,000	4.16%	23.51
2016-2020	50,000	4.35%	23.51
2021-2025	50,000	4.35%	23.51
2026-2030	50,000	4.55%	23.51
2035	50,000	4.55%	23.51

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, the EFP forecasts financial information for electric utilities on an annual basis given a set of inputs and assumptions concerning forecast 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 (NERC) and Census regions, financial statements, revenue requirements,[63] and financial ratios for each stage of production (generation, transmission and distribution).

Electricity prices are forecasted 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 the EFP is an aggregated model, the revenue requirements are allocated according to a representative rate structure for an entire region. The EFP simulates the traditional original-cost or rate-of-return regulatory method where electric utilities have their rates set by local, State, and Federal regulatory commissions. Utilities have rates set so as to allow them to recover their operating costs and earn a rate of return equal to their cost of capital.

The EFP determines the revenues that the aggregated utility requires in order to operate and earn its allowed profit using an average cost based algorithm. Revenues required for wholesale trades, including generation that is provided by nonutilities,[64] are determined in separate submodules of the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)[65] 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 the EFP. These exceptions─sales-leaseback transactions,[66]phase-in plans for new generating units,[67]and disallowances[68]─are

[63] Revenue requirements are the costs that a ratemaking authority allows a regulated utility to recover from ratepayers.

[64] 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, alternate 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).

[65] The electricity capacity planning submodule projects the level of firm power trades for sales from generators. As described in Chapter 3, The Electricity Capacity Planning Submodule, subroutine *EP$PCL* establishes limits on the amount of capacity purchased from nonutilities so that the interest coverage ratio for utilities does not fall below a prespecified level. The electricity fuel dispatch submodule dispatches the available generating units.

[66] 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.

[67] 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.

[68] 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

modeled by exogenously adjusting the forecasted revenue requirements to comply with known information. The revenue that the aggregated utility will actually receive is modeled by adjusting the revenue requirement by a function to simulate regulatory lag.[69] The model solves for internal cash flow and determines the need for external financing in order 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.[70] 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 customer average revenues on a regional basis, the EFP builds financial statements and ratios using accounting methods that simulate standard industry accounting practice.

In recent years restructuring has occurred in many regions of the country. Prices in the generation sector of those regions now reflect a competitive market rather than traditional rate-of-return regulation. Alternative algorithms that incorporate such changes have been added to the EFP. Competitive prices are forecasted by calculating the marginal cost of the generation dispatched for each of the time slices in the EFD.

Alternative regulatory and financial treatments that can be simulated in the EFP are flow-through versus normalized accounting,[71]construction work in progress (CWIP) versus allowance for funds used during construction (AFUDC),[72] alternate levels of allowed rates of return, and varying periods of regulatory lag.

The type of ownership (investor-owned or public) is specified to allow for more precise historic 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

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.

[69] 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 forecasted 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.

[70] 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.

[71] 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.

[72] 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.

Inputs

The EFP is a submodule of the NEMS. As such, there are several inputs to the EFP which come from other NEMS components (Figure 15). The capacity expansion plan is provided by the Electricity Capacity Planning (ECP) submodule. This includes the year the plant enters service, capacity (megawatts), and cost (dollars per kilowatt). The EFP uses this information to calculate the cost of construction as well as when and how these construction costs are incorporated into electricity rates.

The fuel, and operation and maintenance (O&M) costs come from the Electricity Fuel Dispatch (EFD) submodule. The EFP uses these data to calculate the revenues that are 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. The EFP uses these data to allocate costs to customer classes for pricing retail electricity.

Electricity demand comes from the end-use sector demand modules. The EFP uses electricity demand forecasts in its average revenue calculations.[73]

The amount of power purchased from industrial and commercial cogeneration facilities and refineries (kilowatthours) and the amount paid by utilities is passed from the Electricity Fuel Dispatch (EFD) submodule. The EFP includes this information in its average revenue calculations.

Information on firm interregional and international power transfers comes from the Electricity Capacity Planning (ECP) submodule.

Interest rates on bonds rated AA are passed to the EFP from the Macroeconomic Activity Module. These interest rates are used to determine the forecasted costs of capital in the EFP.

[73] In order to calculate average revenues the EFP will calculate revenue requirements and divide the result by total sales in kilowatthours.

Outputs

There are also several outputs from the EFP which are passed to other NEMS components. Electricity price forecasts 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

The EFP has four functions:

1. Electricity pricing;

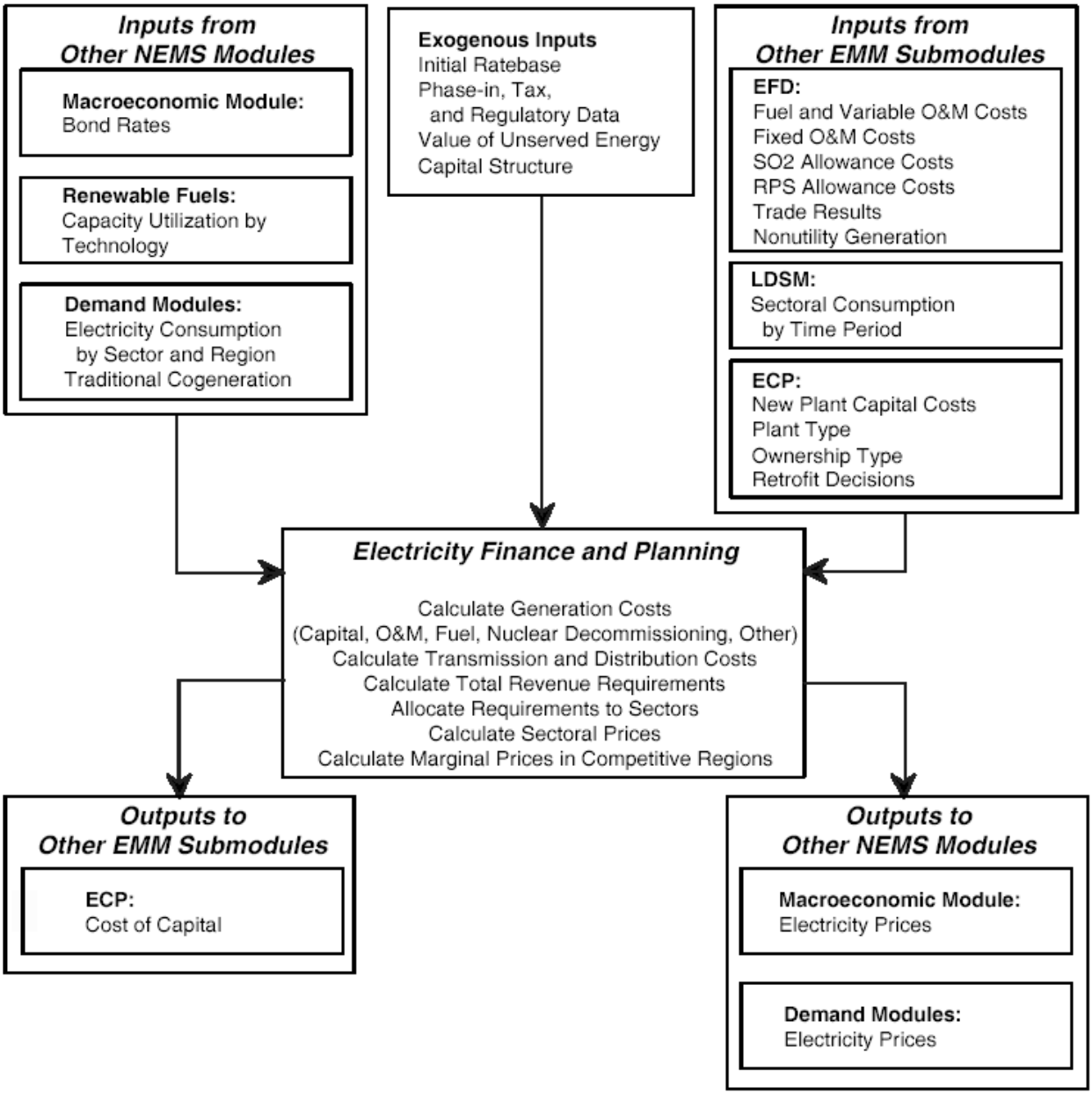
2. Accounting;

3. Determining the cost of capital for electric utilities; and

4. Determining the costs of transmission and distribution services.

The 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.

Figure 15. Input/Output Flows for the Electricity Finance and Pricing Submodule



In those parts of the country where restructuring has occurred, alternative algorithms are needed to determine electricity prices. Algorithms to determine the generation component of price for such regions have been developed. Both transmission and distribution (T&D) are considered to remain under rate of return regulation. Revenue requirements are determined as before. However, the allocation of costs between sectors has been modified for the competitive regions (see Section 5.3, Remaining Algorithms, Price of Electricity, Sectoral Pricing Under A Competitive Generation Scenario).

The first step in calculating generation and transmission prices and distribution average revenues is the determination of 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 ratebase, fixed operation and maintenance (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, in the future, these stages are assumed to be regulated under a cost of service arrangement.

Fixed Costs

The ratebase 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 ratebase for the first modeled year is based on historical data from the previous year with additions or deletions determined by the modeled costs of capacity additions. Additions to the generation ratebase are determined in the Electricity Capacity Planning submodule. Transmission ratebase additions are determined in the EFP as a function of regional non-coincidental peak usage, based on historical relationships between additions and peak usage—though extra transmission is added when necessary to prevent historic declines in transmission builds from resulting in a transmission infrastructure unable to accommodate increases in peak usage. Additions to the distribution ratebase are determined in the 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. The EFP also determines the fixed O&M for the three stages of production.

The forecasted 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 Macroeconomic Activity Module). 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 operation and maintenance costs (O&M) for generation are determined by the Electricity Fuel Dispatch (EFD) submodule. Transmission and distribution related variable O&M costs are determined in the EFP based on historic data as is the rest of the data for the calculation of the revenue requirements.

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 operation and maintenance (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. The choice as to which method to use for which type of costs (capital, fixed O&M, variable O&M, and fuel) for each stage of production is a user option.

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. Others, 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 this 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).

Following are the cost allocation methods available in the 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.[74]

Probability of contribution to peak (PCP) method. The proportion of each class's load in each of the highest twenty 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.

[74] 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.

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. This 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 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 NERC region and selected subregions. 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 that customer class divided by the total sales (kilowatthours) to that customer class, or:

$$\text{Average Revenue}_{ijy} = \text{Total Revenue}_{ijy} / \text{Sales}_{ijy}$$

where:

$\text{Average Revenue}_{ijy}$ = average revenue (retail price) 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

Sales_{ijy} = sales to customer class i in region j, for year y.

Stage of production and industry-wide financial statements are generated for each region and nationally. 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

The emergence of competitive markets for generation in the electricity industry has created the potential of a new distribution of costs and benefits among classes of utility customers. Traditionally, rates were 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. Since rates were set to cover all costs, including return on capital invested, this was referred to as rate-of-return regulation. Rates were 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.

The changing nature of the electric power industry will undoubtedly modify the pattern of allocations of costs between customer classes. Market forces will have a more dominant role.

While all customers are expected to eventually benefit by the introduction of competition in the generation function, the rate and degree of such benefits may vary by customer class. The EFP has been changed to reflect the changing environment. The primary assumption is that the generation component of price is determined in a fully competitive market, while transmission and distribution remain under regulation. Under the new market structure, some consumers may have the ability to bypass the distribution system at relatively low cost by connecting directly to the transmission system or building an on-site generation. Therefore some redistribution of fixed costs may be necessary to retain these customers.

Most analyses of this issue begin and end with Ramsey's model of socially optimal pricing when the firm is faced with the constraint that it must recoup its costs under the condition that the marginal cost is less than the average cost.[75] In this model of pricing, the decision maker is assumed to maximize the sum of consumer surpluses over all customer classes subject to the constraint that the firm recovers its costs. The optimal solution is given by the inverse-elasticities rule under which the markup of price above marginal cost is inversely related to that sector's price elasticity of demand. While this result offers some useful insights, it ignores the possibility that regulators may weigh the economic interests of industrial customers more or less heavily than the economic interests of commercial or residential customers. This of course affects the pattern of sectoral prices that is observed under regulation.

For the restructured regions, a modified Ramsey pricing scheme was implemented. The economic principles underlying the valuation are described in detail later in this chapter.

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 planning 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 (e.g. 0.15 if the standard is set such that 15% of generation must be of the appropriate renewable type) and 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 kilowatt-hour of power sold, where a qualified renewable generator receives one credit for each kilowatt-hour 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 variable cost, and is then added directly to the marginal cost of generation.

Alternative Approaches and Reasons for Selection

The EFP, as the financial and electricity pricing component of EIA's intermediate-term energy modeling system, accounts for two broad-based changes in the industry that are occurring or

[75] Such an approach was found to be economically optimal by Ramsey some 70 years ago. See F.P. Ramsey, "A Contribution to the Theory of Taxation," *Economic Journal*, Vol. 37 (March 1927).

could occur in the next decade: (1) industry structural changes, and (2) capital investment changes.

Changes Related to Industry Structure

The structure of the regulated electric power industry , in which vertically integrated franchise monopolies[76] dominate, was influenced in large part by the Public Utility Holding Company Act of 1935 (PUHCA). This act was passed by Congress as part of the New Deal legislation to break up the large monopoly holding companies that dominated the electric power industry. These holding companies were structured in such a way as to impede regulatory oversight.

This vertical integration of the electric power industry has been breaking down as a result of efforts to increase competition in the power generation arena. In states allowing retail competition, generation, transmission and distribution rates have been unbundled and generation rates for retail electricity customers are determined by an agreement between the customer and the competitive electricity supplier[77]instead of the traditional cost of service approach. FERC's Order 888 has allowed the formation of competitive electricity markets from which utilities and competitive electricity suppliers purchase at least some of their wholesale power. Thus, the three primary stages of production of the industry: generation, transmission, and distribution[78] are modeled separately. Transfer prices are calculated for generation and transmission. The purpose of these prices is to transfer the costs of each of these stages to the distribution stage so that total costs for all of these stages can be included in the calculation of average revenues. In the case of a vertically integrated electric utility, the generation and transmission transfer prices represent the flow of costs (as between divisions within a corporation) that become components of the retail pricing mechanism (which calculates average revenues for distribution). This technique facilitates an analysis of industry structural change, allows for independent assumptions for each of the three stages of production with regard to regulatory and tax treatment, and allows the analyst to use a variety of costing mechanisms with varying underlying economic assumptions for these stages of production.

Separate financial statements are provided for each stage of production on a regional and national basis so that an independent analysis of each will be feasible. Financial statements are provided on an industry-wide basis as well. In these reports, the three stages of production are combined at the regional and national levels to represent a regional vertically integrated utility.

The pricing technique used for retail distribution continues to be the average cost based method. Average revenues are calculated for the four customer classes: residential, commercial, industrial, and transportation. An improved cost allocation algorithm has been implemented so that these customer class average revenues are more meaningful in terms of the actual forecasted cost of service. That is, cost allocation methods in the EFP may use peak load data generated by the Electricity Load and Demand submodule (ELD) as the basis for the allocation of some costs of service so that costs may be more accurately allocated to the customer class responsible for those costs.

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[76] In a franchise monopoly, an electric utility (investor-owned or public) operates in a defined service territory at the exclusion of all other electric utilities.

[77] A competitive supplier can be a generator, power marketer, or power broker that agrees to either directly provide, or arrange the provision of, power for the customer.

[78] Within each stage of production — generation, transmission, and distribution — representations are made of the various ownership categories, regulatory considerations, and economic assumptions that exist now or are likely to exist in the future.

Changes Related to Capital Expenditures

The second broad based change has to do with investment emphasis. In the 1970s and 1980s, most capital expenditures were for construction projects. Throughout the 1990s a sizable amount of capital expenditures were for purposes other than for new construction. They include demand side management (DSM) costs, nuclear decommissioning costs, life extension costs, post operational capital expenditures, and costs and revenues associated with the Clean Air Act Amendments of 1990 (CAA). Since many of the accounting and rate-making issues dealing with these expenditures will be different in the future, the EFP is designed so that an accurate representation of these issues can be made.

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, Forecasting Revenue Requirements, describes the method used to forecast annual revenue requirements. In order to forecast the revenue requirement, one must first forecast the components of the rate base and the expenses. This part describes the algorithms used to calculate and forecast these items. All variables are forecast or input for each year and 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 forecast competitive generation prices. With all of these items forecast, one has nearly all the necessary components to forecast the financial statements and ratios. Section 5.3, Remaining Algorithms, describes the process of using these items to yield forecasts of electric revenue, prices, taxes (both actual and for financial purposes), and financial ratios.

5.1 Forecasting Revenue Requirements

The EFP method of forecasting revenue requirements simulates the outcomes of the regulatory process. The EFP forecast 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 forecast for revenue requirements in any given year is:

(5.1-1)

$$ERRVRQ = (ERRB \cdot ESRR) + ERTFLN + ERTOMN + ERBDE + GENREG + STAREG + FEDREG - EROFFS + ESLLP - EPIND + ERNDFPMT$$

where:[79]

ERRVRQ = revenue requirement[80]

ERRB = rate base

[79] 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.

[80] For accounts that describe ”flows” (e.g., fuel expense, depreciation expense), the value refers to the period January 1 to December 31 of the given year. For accounts that describe “stocks” (e.g., rate base, utility plant), except when otherwise stated, the value refers to the end of the given year value, i.e., value on December 31 of the given year.

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 eleven 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 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:

(5.1-2)
$$ERRB = ERTUP + ERRCWP + ERWC + ERNFSN - ERABDE - ERPRDF - (ERCNBV - ERCNAD) - ESLNDG - EDISNT$$

where:

ERRB = rate base

ERTUP = total utility plant

ERRCWP = Construction work in progress (CWIP) allowed in rate base

ERWC = working capital

ERNFSN = 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 disallowed plant.

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:

(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 on line this year.

The average-year rate base is calculated as the simple average of the beginning-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 on line 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 on line in the middle of a given year, they continue to accrue allowance for funds used during construction (AFUDC) for those months until 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 Utility Plant (ERTUP):

Total Utility Plant (ERTUP) is calculated as:

(5.1-5) $$ERTUP = \sum_{all\ k} (EOBKVL_k) + \sum_{all\ k} (ERBVYE_k) - ERBTIR$$

where:

ERTUP	=	total utility plant
$EOBKVL_k$	=	book value of assets existing in the base year (old assets) of type $_k$ (i.e., distribution)
$ERBVYE_k$	=	book value of assets completed in the forecast horizon (new assets) of type $_k$ which are completed as of the year of forecast
ERBTIR	=	book value of all assets which have been retired during the forecast horizon as of the year of forecast.

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 forecast. Retired assets are all assets. The calculation of the book value of individual new assets is also discussed below.

Construction work in progress (CWIP) allowed in rate base (ERRCWP):

(5.1-6)

$$\boldsymbol{ERRCWP_y = EBRCWP_y + ERRCWP_{(y-1)}}$$

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 1/8 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 prior to 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:

(5.1-7)

$$ERWC = 0.125 \cdot (ERTOMN + ERTFLN)$$

where:

ERWC = working capital

ERTOMN = operation and maintenance costs, excluding fuel

ERTFLN = fuel costs

The calculation of ERTOMN and ERTFLN is discussed below.

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.

(5.1-8)

$$ERNFSN = 3.5 \cdot EFPNUC \cdot ESGNPD$$

where:

ERNFSN = 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):

(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 which plant comes on line, the percent of year 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 EFP, this 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.

(5.1-10) $$ERPRDF = DAD + DAFDC - EREDTF$$

where:

ERPRDF = provision for deferred income taxes

DAD = deferred income taxes due to 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, many 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 cancelled. 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.

(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) $$ERCNAD = ERCNAD + EBABDE + BDE$$

where:

ERCNAD = Accumulated depreciation of canceled projects not in rate base

EBABDE = Accumulated book depreciation all assets by build

BDE = Book depreciation computations

For more information on depreciation, see 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 mitigating 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 or 30 years. The net deferred gain from the sale of the plant is subtracted from the rate base.

(5.1-13) $$ESLNDG = ESLNDG + SLGAIN - AMOR \cdot YRSL$$

where:

ESLNDG = total regional net deferred gain

SLGAIN = net of tax gain over book value from sale

AMOR = amortized amount of tax gain

YRSL = year of sale/leaseback plan

For a detailed discussion of Sale/Leaseback Transactions see 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 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.

(5.1-14) $$EDISNT_y = EDISNT_y + (PIBKVL \cdot (1 - (YRPI/PIBKLF))) \cdot DISPER$$

where:

$EDISNT_y$ = net disallowed plant, year y

PIBKVL = book value of phase-in plant (input)

YRPI = index of 1st 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:

(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:

(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 debit outstanding from previous year

ESEMDB = embedded cost of long-term debt in the year previous to the first forecast 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 forecast 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 deferrals–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: i) the embedded cost in the previous year (ESEMDL); ii) the embedded cost in the base year (ESEMDB); and iii) the cost of new long-term debt issued in the current year (ESRTNB). Only debt issued before the forecast period is assumed to be retired. This is appropriate, given the mid-range forecast period over which EFP forecasts.

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 in NEMS please see Appendix 5.G.

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,[81] 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.[82] A corporation with a beta equal to 1.5 means that the return on that 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)

B = The beta coefficient

R_M = the return on the market.

[81] For a detailed description of CAPM, see Energy Information Administration, *Investor Perceptions of Nuclear Power*, DOE/EIA-0446 (Washington, DC, May 1984).

[82] 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.

For the purposes of the EFP, the risk-free rate of return is the real Treasury bill (T-bill) rate from the NEMS Macroeconomic Activity Module (MAM) plus an exogenous inflation rate.[83] The return on the market is also an exogenous input.[84] This means that the beta coefficient provides the dynamic properties of the cost of equity to electric utilities in NEMS. Through the beta coefficient, the EFP translates the forecasts of operational and financial conditions into the cost of equity for utilities. This, in turn, 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 characterics similar to the restructured electricity generation sector.

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.

(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 forecast 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 forecast 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 forecast period

The values of ESEMPB and ERPFL (for the first forecast year) are input into EFP. These values can be derived from historical financial statements such as the FERC Form 1.

[83] 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.

[84] It is beyond the scope of NEMS to forecast a return on the stock market.

Fuel Costs (ERTFLN):

Fuel costs in each forecast year are derived from the results of the dispatch exercise.

(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 NUGs and inter-regional 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, operation and maintenance costs are input to EFP from other modules being used to drive EFP. Again, if necessary, these costs are inflated each year by a user-defined inflation rate. Operation and maintenance costs are calculated differently for generation, transmission, and distribution.

Generation O&M:

(5.1-20) $$ERTOMN_{ISECT=1} = (ERTOM + OVERPR + ERTOMF + OMLE) \cdot ESGNPD$$

where:

$ERTOMN_{ISECT=1}$ = operation and maintenance costs of the generation sector, excluding fuel cost, in nominal dollars

ERTOM = real dollar production related variable operation and maintenance expenses

OVERPR = real dollar production and maintenance expenses allocated to the production function (e.g., 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:

(5.1-21) $$ERTOMN_{ISECT=2} = (ERTOMT + OVERTR) \cdot ESGNPD$$

where:

$ERTOMN_{ISECT=2}$ = operation and maintenance costs of the transmission sector, excluding fuel cost, in nominal dollars

ERTOMT = real dollar transmission operation and maintenance expenses

OVERTR = real dollar overhead-related O & M expenses allocated to transmission (e.g., general administration)

ESGNPD = inflation index to convert real dollars to nominal dollars

Distribution O&M:

Operation and maintenance costs are input to EFP from the distribution model being used to drive EFP. If necessary, these costs are inflated each year by a user-defined inflation rate.

(5.1-22) $$\boldsymbol{ERTOMN_{ISECT=3} = (ERTOMD + OVERDS) \cdot ESGNPD}$$

where:

$ERTOMN_{ISECT=3}$ = operation and maintenance costs of the distribution sector, excluding fuel cost, in nominal dollars

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 (e.g., 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) $$\boldsymbol{ERBDE_y = (EBBKVL - EBABDE_{y-1}) / (ESBKLF - (YEAR - EBSYR))}$$

and

$$\boldsymbol{EBABDE_y = \sum_{i=EBSYR}^{y} ERBDE_i}$$

$$\textbf{for y} = \boldsymbol{EBSYR} \textbf{ to } \boldsymbol{EBSYR + ESBKLF - 1} \textbf{ (i.e., over servicelife of assets)}$$

(5.1-24)

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 on line

$EBABDE_y$ = 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 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. It is assumed that these taxes each year will be a constant percentage of revenue requirements.

(5.1-25) $$GENREG = EGTXRT \cdot ERRVRQ + ERPRTX + ERSLTX$$

where:

GENREG = ral 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 which is calculated from base-year data (e.g., FERC Form 1, Form EIA-412). Including ERRVRQ on the right-hand side of the equation appears to make this discussion circular (i.e., 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 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:

(5.1-26)

where: $$STAREG = (ERRVRQ - ERTFLN - ERTOMN - ERTDWO - ERTIEX - ESLLP) \cdot ESSTXR$$

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.

(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 discussed above (See section above on *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.

(5.1-30)
$$ERAMD = ERTUP + ERBCWP + ERWC + ERNFSN + EPIDEF - ERABDE - ERPRDF - ERDITC - EDISNT - ESLNDG$$

where:

ERTUP = total utility plant (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:

(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 section: **Resolution of ERRVRQ "Circular" Argument**. ESFTXR is a user-supplied input. FEDREG includes the effects of the ITC or the tax savings due to 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 construction work in progress (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 (i.e., 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:

(5.1-32) $$EROFFS_y = AFUDC_y \cdot ESRBAF$$

where:

$EROFFS_y$ = AFUDC offset, year y.

$AFUDC_y$ = AFUDC year y

ESRBAF = Percent of AFUDC/CWIP which receives offset treatment

See Appendix 5.B. for further discussion.

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.

(5.1-33) $$ESLLPN = ESLLP - ESLAGN$$

where:

ESLLPN = net lease payment

ESLLP = annual lease payment

ESLAGN = amortization of gain

See Appendix 5.E. for further discussion.

Net Deferred Phase-in Costs (EPIND):

Under tradition cost-of-service, rate-of-return regulation, the rate impacts of the capital costs of a new asset coming on line 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 has occurred when energy commodity prices are low, new power generation technologies are not much more efficient than previous technologies, a utility has overbuilt capacity, and/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 phased-in more evenly over the life of the asset.

(5.1-34) $$EPIND = EPIND + DEFCST$$

where:

EPIND = net (pre-tax) deferred costs

DEFCST = deferred (after tax) cost

See Appendix 5.F. for 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 eleven fields. Each data record describes a nuclear unit or a plant containing more than one unit (only if unit parameters are similar and

utility-owner did not specify data by unit). The database is input into NEMS in the phasein input data file.

After the data is input, the nuclear decommissioning methodology 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 of the steps 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. As described above, for some nuclear units, this information was not available. For units where the information is not available, the values must be estimated. This information is estimated in this step under the assumption that the payment patterns for these units is similar to the average pattern observed for all units for which data is 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 includes the impact of escalation and inflation which occurs between the beginning of 1990 and the date for which input values actually apply.

Perform Annual Calculations:

For each forecast year, the fund balance for each unit is calculated as:

(5.1-35) $$Balance_y = Balance_{y-1} + Earnings_y - Tax_y - (AdministrativeCost)_y + Payment_y$$

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 (i.e., 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 "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 somewhat linear presentation above, these equations seem to present a circular argument. 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. Using the method known as algebraic substitution, one can solve for the value of ERRVRQ, as follows:

First, the above equations (5.1-25), (5.1-26), and (5.1-31) can be substituted into equation (5.1-1) to yield:

(5.1-36)
$$ERRVRQ = \ldots + ERRVRQ \cdot EGTXRT + (ERRVRQ - \ldots) \cdot ESSTXR + (ERRVRQ - \ldots - STAREG - GENREG) \cdot ESFTXR$$

Next, substituting equations (5.1-25) and (5.1-26) into the above equation and gathering like terms yields:

(5.1-37)
$$ERRVRQ = \ldots + ERRVRQ \cdot EGTXRT + (1 - ESFTXR) + (ERRVRQ - \ldots) \cdot ESSTXR \cdot (1 - EXFTXR) + (ERRVRQ - \ldots) \cdot ESFTXR$$

Next, moving all terms on the right hand side of the equation that contain the variable ERRVRQ to the left hand side yields:

(5.1-38)
$$ERRVRQ \cdot (1 - EFTXRT \cdot (1 - ESFTXR) - ESSTXR \cdot (1 - ESFTXR) - ESFTXR) = \ldots + (- \ldots) \cdot ESSTXR \cdot (1 - ESFTXR) + (- \ldots) \cdot ESFTXR$$

Finally, dividing the equation on both sides by the constant on the left hand side yields:

(5.1-39)

$$ERRVRQ = \frac{\ldots + (-\ldots) \cdot ESSTXR \cdot (1 - ESFTXR) + (-\ldots) \cdot ESFTXR}{1 - EGTXRT \cdot (1 - ESFTXR) - ESSTXR \cdot (1 - ESFTXR) - ESFTXR}$$

This equation yields a unique value for ERRVRQ. This value can then be substituted back into equations (5.1-25), (5.1-26), and (5.1-31) to yield values for the remaining variables.

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, maintenance and marginal general and administrative (G&A) costs, (2) taxes, and (3) a reliability price adjustment equal to the marginal cost of unserved energy. Since transmission and distribution are assumed to remain regulated, the total price is the sum of the generation costs and no changes were made in the calculation of the average transmission and distribution costs. There is no explicit representation of capital recovery in the competitive price of electricity generation, as 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:

(5.2-1)

$$Pcomp_{ryt} = E_{ryt} + C_{ryt} + GA_{ry} + Tax_{ryt} + TD_{ry}$$

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_{ryt} = the reliability adjustment of price in region r, year y, period t (cents per kilowatthour),

GA_r = general and administrative costs related to generation in period t for region r, year y (cents per kilowatthour),

Tax_{ryt} = recovery of Federal income taxes and all other taxes in region r, year y, period t (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 9 time periods used in the EFD submodule.

The model has the 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 (i.e. a weight of 50% implies a ½ year lag). This may be desired when fuel prices, particularly natural gas, are fluctuating quickly. Even in a competitive environment, fuel price changes may not immediately be reflected in the spot market prices, as companies may purchase their fuel at longer-term contract prices.

The marginal production costs include more than just the operating costs listed above. Over the mid-term, these costs—primarily maintenance costs and overhead expenses—do change with the level of output and are therefore variable. Since the G&A (or overhead) costs are avoidable over the mid-term, they must be recovered over the course of the year or it would not pay to keep the plant running. All taxes other than Federal income taxes (i.e., State income taxes, sales taxes, and property taxes) are aggregated and treated as a gross receipts tax (revenue tax).

The reliability price adjustment reflects the cost of maintaining a margin of safety for generation to meet electricity demand. Such a cost can be quantified in several ways.[86] This model evaluates the reliability price adjustment on the basis of estimates of the marginal cost of expected unserved energy. It is assumed that consumers will curtail electricity usage when the spot price of electricity exceeds their cost of unserved energy. The cost of unserved energy may be revealed through energy service contracting mechanisms, where consumers are offered varying levels of reliability (greater or lower probability of a service interruption) for varying contract prices, and through behavioral responses to spot prices by spot market participants.

Marginal unserved energy is the quantity of unserved energy satisfied by the last (or marginal) unit of generating capacity. Unserved energy is the difference between supply and demand during periods when, at a given price, demand exceeds supply. Expected unserved energy is a derived quantity based on the expectation of the joint stochastic distribution of supply and demand. Expected unserved energy does not imply a system failure. Rather, it is an expected value calculated from an uncertain amount of generating capacity and an uncertain level of demand for each pricing period.[87]

In this model, the expected amount of unserved energy for each region for each dispatching period is calculated from the following inputs:

1. The capacity of each generating plant in each region for each season of the year (total capacity adjusted by planned outages)

2. An estimate of the probability of a forced outage for each plant

3. Stochastic hourly load data (projections of demands with an uncertainty factor that creates probability distributions from the deterministic values for demand).

[86] See F.C. Schweppe, M.C. Caramanis, R.D. Tabors, and R.E. Bohn, *Spot Pricing of Electricity* (Boston, MA: Kluwer Academic Publishers, 1988), p. 136. Another method to quantify this component is to use a market-clearing approach, also described in Chapter 6 of Schweppe et al.

[87] Expected unserved energy calculations are performed for the system in its current state and for the system augmented by a small amount of capacity (perhaps equal to a small turbine). These calculations yield the reduction in unserved energy for each kilowatt of additional capacity that is brought into service or, stated another way, the change in unserved energy relative to a change in capacity (marginal unserved energy).

The cost of unserved energy (or value of unserved energy) is an input assumption, because the value of unserved energy is difficult to estimate. The costs for consumers can vary widely. Estimates range from $2 to $25 per kilowatthour and are affected by the type of consumer, the timing of service curtailment, the length of the interruption, and the amount of warning before curtailment begins. For example, an outage without warning during the dinner hour is much more expensive for a restaurant owner than it is for most residential consumers. Hence, a restaurant owner (and commercial consumers in general) would be willing to pay more for reliable electric power than would most residential consumers. Further, a disruption is more costly if it lasts for a longer period of time and creates costs associated with food spoilage, prolonged loss of residential heating and cooling, and the like.

As mentioned above, competitors may have the means to determine the value of unserved energy through the price discovery role of competitive markets. If the revealed cost to consumers of an outage is actually lower than the assumed value that system planners have traditionally used, it means that reserve margins may fall. Lower reserve margins could have important implications for system operating costs and electricity prices.[88]

Mathematically, the reliability adjustment of price is represented as:

(5.2-2)

$$C_{ryt} = \left(\frac{\partial UE}{\partial G} \right)_{ryt} \cdot V(UE) \quad ,$$

where:

C_{ryt} = reliability adjustment of price, year y, pricing period t for region r (cents per kilowatthour),

$\left(\frac{\partial UE}{\partial G} \right)_{ryt}$ = change in unserved energy with respect to a change in generating capacity (reduction in unserved energy that results from an increase in capacity) in region r, year y, dispatch period t (kilowatthours per kilowatt per hour), and

V(UE) = assumed value of a kilowatthour of unserved energy (cost to consumers of a kilowatthour of electricity during a blackout, in cents per kilowatthour).

The reliability adjustment of spot prices for each pricing period, region, and year of the projection is calculated by multiplying the change in unserved energy per kilowatt of additional generating capacity (marginal unserved energy), calculated as described in the previous paragraphs, multiplied by the assumed value of unserved energy.

Modifications to three submodules were needed to calculate competitive prices. The capacity cumulants are calculated in subroutines ELEFD and ELRNEW of the fuel dispatch module; demand cumulants are calculated in subroutine DSMEFD of the load and DSM submodule. The reliability component is a function of the capacity and demand cumulants in each slice. All of the subsequent calculations were performed in the electricity pricing submodule. The calculation of the reliability component for each slice is performed in subroutine ELREL . This calculation is described in detail in Appendix 5.G. The total price for each slice is summed in subroutine COMPPRC. Annual prices for each of the end-use service are calculated in subroutine RATES2. These prices were modified to reflect the transition to full competition, sectoral adjustments and converted to Census division level in the subroutine ELSET. Furthermore, subroutine REVGAP

[88] Energy Information Administration, *Annual Energy Outlook 1996*, DOE/EIA-0383(96) (Washington, DC, January 1996), p. 30.

was added to summarize the relationship between revenues and total costs for each region. Finally, subroutine RATES was modified to include the-transition price freezes and reductions in competitive regions, as well as the large amount of California load effected through 2010 by long-term contract prices as negotiated by the California Department of Water Resources in 2001. The changes in rates are described in greater detail below in 5.3. Remaining Algorithms,

Electricity Pricing During the Transition to Competition.

5.3. Remaining Algorithms

Section 5.1 of this chapter described the EFP algorithms used to forecast the major components of revenue requirements to forecast regulated electricity prices based on average cost calculations, while Section 5.2 of this section described how to calculate competitive prices. This section describes the remaining algorithms which are used to yield forecasts of electric revenues, allocation of costs to customer classes, the regulated price of electricity, taxes (both current and for financial purposes), financial ratios, and other miscellaneous items.

Electric Revenues:

Electric 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. EFP calculates electric revenues under five different assumptions: i) no lag, ii) 1-year lag, iii) one-quarter-year lag, iv) one-half-year lag, and v) three-quarter-year lag.

In a no-lag scenario, rates are based on current year experiences and rate base so that electric revenues are equal to the revenue requirements calculated in part 1 above:

(5.3-1) $$ERRVLG = ERRVRQ$$

where:

ERRVLG = electric revenues

ERRVRQ = revenue requirements

In a 1-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 variables are same 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 1 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 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 present 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 recovered as they are incurred. The overall approach is that the price of electricity is comprised of two parts — a 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 1-year lag cases are used in the other scenarios (e.g., one-half-year lag).

Forecast sales of electricity are passed to EFP from the dispatch module (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.

Sales Method:

Costs are allocated on the basis of the proportion of total sales to the class as follows:

(5.3-3a) $$DEMFAC_{1j} = SALCLS_{rj} / SALTOT$$

where:

$SALCLS_{rj}$ = the total sales of electricity by region r to customer class j

SALTOT = the total sales of electricity to all classes

Customer Method:

Costs are allocated based on the number of customers in each customer class:

(5.3-3b) $$DEMFAC_{4j} = CUST_j / TOTAL$$

where:

$CUST_j$ = the total number of customers by 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:

(5.3-3c) $$DEMFAC_{5j} = SECANNUALPEAK_{1rj} / TOTAL$$

where:

$SECANNUALPEAK_{1rj}$ = the system peak 1 load in region r attributable to customer class j.

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:

(5.3-3d) $$DEMFAC_{6j} = SECANNPEAAVPCP_{rj} / TOTAL$$

where:

$SECANNPEAAVPCP_{rj}$ = 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:

(5.3-3e) $$DEMFAC_{7j} = SECANNUALPEAK_{2rj} / TOTAL$$

where:

$SECANNUALPEAK_{2rj}$ = the load at the time of the customer peak 2, in region r, 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:

(5.3-3f) $$DEMFAC_{8j} = (SYSTEMLF_r \cdot DEMFAC_1) + [(1 - SYSTEMLF_r) \cdot DEMFAC_5]$$

where:

$SYSTEMLF_r$ = the system load factor by region r

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 probability of contribution to peak instead of the coincident peak method:

(5.3-3g) $$DEMFAC_{9j} = (SYSTEMLF_r \cdot DEMFAC_1) + [(1 - SYSTEMLF_r) \cdot DEMFAC_6]$$

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:

(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 l

and revenues are allocated to the class:

(5.3-5) $$REV_{jl} = COSTFC_{kjl} \cdot COST_{kl}$$

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 electric revenues forecast and allocated, the forecast price of electricity is straightforward:

(5.3-6) $$EPRICE_{rjl} = REV_{jl} / SALCLS_{ryj}$$

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

$SALCLS_{r}$ = sales to customer 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 to historic prices for benchmarking and subsidy calculation.[89] The prices for transportation are not benchmarked because (1) there is no relevant historic 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 historic prices may be due to differences between the modeled allocation techniques and those being used in practice, and they may be due to 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 historic and modeled proportions of revenues to each of the three classes are determined. Historic proportions are:

(5.3-7) $$REVHPCT_{jy} = REVH_{rjy} / REVHRCI_{y}$$

where:

$REVHPCT_{jy}$ = the actual proportion of revenues allocated to customer class j in year y

$REVH_{rjy}$ = the actual revenues, by region r, allocated to customer class j in year y

$REVHRCI_{y}$ = the actual total revenues allocated to all three classes in year y

The modeled proportions are:

(5.3-8) $$REVPCT_{jy} = REV_{jy} / REVRCI_{y}$$

where:

[89] This benchmarking/subsidization technique is not used for the generation or transmission transfer price calculations.

$REVPCT_{jy}$ = the modeled proportion of revenues allocated to customer class j in year y

REV_{jy} = the modeled revenues allocated to customer class j in year y

$REVRCI_y$ = the modeled total revenues allocated to all three classes in year y

The historic proportion of sales attributable to each customer class is:

(5.3-9) $$SLSHPCT_{jy} = SALH_{jy} / SLSHRCI_y$$

where:

$SLSHPCT_{jy}$ = the actual proportion of sales to customer class j

$SALH_{jy}$ = the actual sales to customer class j in year y

$SLSHRCI_y$ = the actual sales to all three classes in year y

The modeled proportion of sales is:

(5.3-10) $$SLSPCT_{jy} = SALCLS_{jy} / SLSRCI_y$$

where:

$SLSPCT_{jy}$ = the modeled proportion of sales to customer class j in year y

$SALCLS_{jy}$ = the modeled sales to customer class j in year y

$SLSRCI_y$ = the modeled sales to all three classes in year y

These 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) $$SUBPCT_j = (REVHPCT_j - SLSHPCT_j) - (REVPCT_j - SLSPCT_j)$$

where:

$SUBPCT_j$ = the implied percent of subsidy for customer class j

$REVHPCT_j$ = the actual proportion of revenues allocated to customer class j

$SLSHPCT_j$ = the actual proportion of sales to customer class j

$REVPCT_j$ = the modeled proportion of revenues allocated to customer class j

$SLSPCT_j$ = the modeled proportion of sales to customer class j

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:

(5.3-12) $$EPRICE_{rj} = (REV_j + (REVRCI \cdot SUBPCT_{rj})) / (SALCLS_{rj})$$

where:

$EPRICE_{rj}$ = the benchmarked/subsidized price of electricity by region r to customer class j

REV_j = the costs (revenues) allocate do customer class j before the benchmarking/subsidization routine

REVRCI = total costs allocated to the three customer classes

$SUBPCT_{rj}$ = benchmarking/subsidy percent by region r, for customer class j

$SALCLS_{rj}$ = electricity sales by region r, to customer class j

Sectoral Pricing Under A Competitive Generation Scenario:

It is assumed that in a competitive generation market, prices will be divided among customer classes (sectors) differently than under a regulated market. Specifically, large customers are expected to have more opportunities to leave the grid than previously. If firms with large loads leave the grid, the price of distribution will be increased for those customers who must continue to buy on-grid electricity. It is assumed that regulators of distribution utilities will thus be more likely to offer these large customers lower distribution prices to entice them to continue to buy on-grid energy. For restructured regions, a modified Ramsey pricing scheme is implemented. The economic principles underlying the valuation are described below.

Suppose that the regulator sets prices for the firm so it maximizes a weighted sum of consumer surpluses over the customer classes served by the firm. For simplicity, we model two customer classes. Specifically, assume there are two customer classes and the decision maker maximizes the function $\theta_1 CS_1 + \theta_2 CS_2$, where CS_j is the consumer surplus of customer class j and θ_j is the weight that the decision maker attaches to j's level of welfare. The case where the decision maker is indifferent to the welfare of j is represented by $\theta_j = 0$. The case where the economic interests of customer class 1 are twice as important as those of customer class 2 can be represented as $\theta_1 = 4/3$ and $\theta_2 = 2/3$ while the case where 1's interests are three times more "important" than 2's would be represented by $\theta_1 = 1.5$ and $\theta_2 = .5$.

Our model is then:

(5.3-13) $$Max \quad \theta_1 CS_1 + \theta_2 CS_2$$

such that:

(5.3-14) $$P_1X_1 + P_2X_2 - C_j(X_1X_2) = 0$$

This merely states that the regulator attempts to maximize the weighted consumer surplus subject to the constraint that the revenues for the regulated utility must equal its costs. This maximization problem may be solved through the application of Lagrange multipliers. The solution is:

(5.3-15) $$\frac{P_j - C_j'}{P_j} = \frac{1-\theta_j/\lambda}{|\varepsilon_j|}, j = 1,2$$

where ε_j is customer class j's price elasticity of demand, λ is a scalar to preserve feasibility of the solution, and $C_j' = \partial C(X_1, X_2)/\partial X_j$ is the marginal cost of production. Inspection of 5.3.4.5c reveals that the price-cost margin varies inversely with the absolute value of the price elasticity of demand. It also indicates that regulatory preferences will affect the margin between price and marginal cost. Specifically, if the decision-maker attaches zero weight to the interests of customer class j, then θ_j is zero and the price cost margin reduces to $1/|\varepsilon_j|$, a level equivalent to the unconstrained monopoly solution.

Now assume that the electricity is distributed by a regulated natural monopolist. We have three customer classes: residential, commercial and industrial. Each class purchases X_j from the generating industry at the price PG_j per unit. Assume the total cost of distribution is related to the amount of power distributed to each customer class, i.e. the total cost of distribution is $C^D(X_R^S, X_C^S, X_I^S)$ where X_j^S is the amount of power that the distributor delivers to customer class j through its system. The industrial and commercial classes are assumed to have the threat of by-pass; that is, the ability to leave the system through self-generation or other means. We let $X_j^S = X_j - X_j^B$, where X_j^B is the amount of power that is self-generated, bypassing the system. Let η represent the elasticity of nongrid supply, i.e. $\eta = (\partial X_j^B/\partial P_j)(P_j/X_j^B)$, and S_j^D be the share of total generation purchased by the industrial class that uses the distribution system, i.e., $S_j^D = X_j^S/X_j$. In contrast, the residential class must purchase all of its power through the local distribution system. Assume that the amount of power bypassed is positively related to the end use price of electricity, i.e. $\partial X_j^B/\partial P_j > 0$ where P_j is the total end use price. Finally, assume that the end-use price is the sum of the generation price (PG_j) and the distribution charge (PD_j).

Based on the above discussion, the decision maker is assumed to maximize the function:

(5.3-16) $$L = \theta_R CS_R + \theta_C CS_C + \theta_I CS_I + \lambda[PD_R X_R^S + PD_C X_C^S + PD_I X_I^S - CD(X_R^S, X_C^S, X_I^S)]$$

For the customers in the residential class , $X_j^S = X_j$, and thus the following result can be obtained:

(5.3-17) $$PD_j = \frac{CD_j' |\varepsilon_j| + PG_j(1-\theta_j/\lambda)}{|\varepsilon_j| - (1-\theta_j/\lambda)}$$

Customers in the industrial and commercial classes are assumed to have the option to bypass the distribution system and thus, for instance, $X_j^S = X_j - X_j^B$. Let η represent the elasticity of nongrid supply, i.e. $\eta = (\partial X_j^B/\partial P_j)(P_j/X_j^B)$, and S_j^D be the share of total generation purchased by customer class j that uses the distribution system, i.e., $S_j^D = X_j^S/X_j$.

Assuming that the regulator sets the price of distribution under the belief that price of generation does not change as a result of his action, one can solve the constrained system to find:

$$PD_j = \frac{\frac{CD_j'}{S_j^D}[|\varepsilon_j| + \eta(1 - S_j^D)] + PG_j(1 - \theta_j/\lambda)}{\frac{1}{S_j^D}[|\varepsilon_j| + \eta(1 - S_j^D)] - (1 - \theta_j/\lambda)}$$

(5.3-18)

It is known that revenues must equal costs. Therefore:

(5.3-19)
$$REV = \sum_{j=1}^{j=3} \left(\frac{\frac{CD'}{S^D}[|\varepsilon| \eta(1 - S^D)] + PG(1 - \theta/\lambda)}{\frac{1}{S^D}[|\varepsilon| \eta(1 - S^D)] - (1 - \theta/\lambda)} \right) Q_j$$

where:

REV = total revenues required for transmission and distribution,

Q_j = total consumption in customer class j, and

S^D, CDI', ϵ_j, η and θ_j are all known.

This is cubic in λ. The model then expresses λ as the polynomial equation:

5.3-20)
$$coff(1) \cdot \lambda^3 + coff(2) \cdot \lambda^2 + coff(3) \cdot \lambda + coff(4) = 0$$

Defining:

(5.3-21)
$$\alpha_j = newtd/Sdval \ (eps_j + nuval \ (1 - Sdval)) + PG_j$$
$$\beta_j = -1 \cdot pg_j \cdot \theta_{jr}$$
$$\gamma_j = (eps_j + nuval \ (1 - Sdval))/Sdval - 1$$

where:

Newtd = marginal cost of T&D,

Sdval = fraction of consumption available for bypass,

Eps_j = Elasticity of consumption for customer class j,

$Nuval_j$ = Elasticity of bypass for customer class j,

PG_j = Generation price to customer class j,

θ_{jr} = weight that the decision maker attaches to the level of welfare for customer class j in region r.

(5.3-22)

$$\begin{aligned} COFF(1) = {} & totrev \cdot \theta_{Rr} \cdot \theta_{Cr} \cdot \theta_{Ir} \\ & - \beta_R \cdot (Q_R + transal) \cdot \theta_{Cr} \cdot \theta_{Ir} \\ & - \beta_C \cdot Q_C \cdot \theta_{Rr} \cdot \theta_{Ir} \\ & - \beta_I \cdot Q_I \cdot \theta_{Cr} \cdot \theta_{Rr} \end{aligned}$$

where:

Totrev = total revenues required for T&D,

Q_j = consumption of electricity in customer class j, and

Transal = consumption of electricity in transportation sector.

(5.3-23)

$$\begin{aligned} COFF(2) = {} & totrev \cdot (\theta_{Rr} \cdot \theta_{Ir} \cdot \gamma_C + \gamma_R \cdot \theta_{Cr} \cdot \theta_{Ir} + \theta_{Rr} \cdot \theta_{Cr} \cdot \gamma_I) \\ & - (Q_R + transal) \cdot (\alpha_R \cdot \theta_{Cr} \cdot \theta_{Ir} + \beta_R \cdot \gamma_I \cdot \theta_{Cr} + \beta_R \cdot \gamma_C \cdot \theta_{Ir}) \\ & - Q_C \cdot (\alpha_C \cdot \theta_{Rr} \cdot \theta_{Ir} + \beta_C \cdot \gamma_I \cdot \theta_{Rr} + \beta_C \cdot \gamma_R \cdot \theta_{Ir}) \\ & - Q_I \cdot (\alpha_I \cdot \theta_{Rr} \cdot \theta_{Cr} + \beta_I \cdot \gamma_C \cdot \theta_{Rr} + \beta_I \cdot \gamma_R \cdot \theta_{Cr}) \end{aligned}$$

(5.3-24)

$$\begin{aligned} COFF(3) = {} & totrev \cdot (\theta_{Rr} \cdot \gamma_C \cdot \gamma_I + \theta_{Cr} \cdot \gamma_R \cdot \gamma_I + \theta_{Ir} \cdot \gamma_R \cdot \gamma_C) \\ & - (Q_R + transal) \cdot (\alpha_R \cdot \gamma_I \cdot \theta_{Cr} + \alpha_R \cdot \gamma_C \cdot \theta_{Ir} + \beta_R \cdot \gamma_C \cdot \gamma_I) \\ & - Q_C \cdot (\alpha_C \cdot \gamma_I \cdot \theta_{Rr} + \alpha_C \cdot \gamma_R \cdot \theta_{Ir} + \beta_C \cdot \gamma_R \cdot \gamma_I) \\ & - (Q_I) \cdot (\alpha_I \cdot \gamma_C \cdot \theta_{Rr} + \alpha_I \cdot \gamma_R \cdot \theta_{Cr} + \beta_I \cdot \gamma_R \cdot \gamma_C) \end{aligned}$$

(5.3-25)

$$\begin{aligned} COFF(4) = {} & totrev \cdot \gamma_R \cdot \gamma_C \cdot \gamma_I \cdot \\ & - \alpha_R \cdot (Q_R + transal) \cdot \gamma_C \cdot \gamma_I \\ & - \alpha_C \cdot Q_C \cdot \gamma_R \cdot \gamma_I \\ & - \alpha_I \cdot Q_I \cdot \gamma_R \cdot \gamma_C \end{aligned}$$

A Newton-Raphson iterative method is used to solve for λ. Given λ, Equation 5.3-23 may be solved directly. This gives the T&D price for each sector.

This equation represents the optimal pricing strategy by the regulator. As long as the price of distribution is above marginal cost, it is worthwhile to continue to supply service. As the share of non-grid service decreases, the price approaches that which might be set if no by-pass were available. This model gives a framework for analysis given a regulated distribution system and customers with different elasticities and abilities to avoid the distribution system.

Given λ, equations of the form of 5.3-25 are then solved for the T&D cost for each sector, which is added to the generation price to produce the total regional price.

The generation price PG_j, the total consumption by customer class Q_j, and the total revenue requirement for T&D are all calculated endogenously by region. Only the initial and final projection value of the national level of bypass are exogenous. Calculation of SDVAL, the fraction of load available for bypass in each region for each year of the projection, is described below.

Calculation of Annual Bypass:

Only the national bypass fraction is an exogenous input. Shares of bypass are then calculated. At the national level, the share of bypass in year y for sector j is projected to be equal to its share in 2020 multiplied times a logistical market penetration factor:

(5.3-26)
$$Nationalshr_{jy} = Nationalshr_{j,2020} \cdot \frac{(\exp(y - midyear))}{(1 + \exp(y - midyear))}$$

where:

$Nationalshr_{jy}$ = share of bypass in customer class j in year y

midyear = midpoint of forecast

The regional share of bypass must then be determined. There are two essential factors that will shape the regional distribution of self-generation: the price of electricity from the grid relative to its marginal cost and the average level of consumption per customer. These parameters are used to calculate the regional share of the total national bypass by:

(5.3-27)
$$allocationweight_{jr} = \frac{\ln(Markup_{jr}) + \ln(Consfactor_{jr})}{\sum_r [\ln(Markup_{jr}) + \ln(Consfactor_{jr})]}$$

where:

$Markup_{jr}$ = markup of the generation price over marginal cost for customer class j in region r

$Consfactor_{jr}$ = ratio of average consumption per customer in customer class j in region r relative to the average consumption for customer class j over all regions.

Furthermore, all of the regional shares must sum to the national share of consumption that may use bypass. A normalization factor is then calculated by:

(5.3-28)
$$Normalizationfactor_{jy} = \frac{Nationalshr_{jy}}{\sum_r conshr_{jry} \cdot allocationweight_{jr}}$$

where:

$conshr_{jry}$ = share of customer class j's national consumption in region r, year y.

This aggregate projection for the sector is used to calculate a factor for the region based on the region's consumption and its allocation weight:

It follows that the bypass share will be:

(5.3-29) $$bypassshr_{jy} = Normalizationfactor_{jy} \cdot allocationweight_{jr}$$

The resulting regional shares are used to calculate sectoral prices by region in Equations 5.3-18 through 5.3-25 above.

Electricity Pricing During the Transition to Competition

When all or a majority of electricity sales within an electricity supply region come from deregulated states, this region is assumed to be fully or partially competitive. It is assumed that there is a gradual 10-year transition to fully competitive pricing from the inception of deregulation in competitive regions. This is the estimated amount of time needed to complete collection of stranded costs, consumer education concerning electricity choices, and resolution of market imperfections. It also accounts for the time needed for an adequate number of suppliers to enter the market and learn to be cost-efficient enough to stay in the market and keep it competitive. Thus, the competitive proportion of sales in a deregulated region for the first 10 years of the inception of retail deregulation is calculated as:

(5.3-30) $$compSLSHPCT_{ry} = totcompSLSHPCT_{ry} \cdot (10\% \cdot compyear_{r})$$

where:

$compSLSHPCT_{ry}$ = the actual competitive proportion of sales in region r in year y

$totcompSLSHPCT_{ry}$ = the total proportion of sales within competitive states in region r in year y

$compyear_{r}$ = the number of years the market has been deregulated in region r (the first year of deregulation equals 1)

The exception to this rule is in the Mid-Atlantic region, where research has shown it to be more competitive than other regions. Thus, for this region only, we assume it to be 40 percent competitive at the start of competition, increasing its competitiveness by 10 percent each year. Thus, NEMS calculates a fully competitive price by the seventh year after the start date of competition instead of the 10th year as for the other competitive regions.

Within a competitive region, it is assumed that the same percentages of competitive and regulated pricing as the percentages of electricity sales in the deregulated and regulated states in that region, respectively. For supply regions with more than half of their electricity sales in competitive states:

(5.3-31) $$EPRICE_{jry} = (regEPRICE_{jry} \cdot \%regSLSHPCT_{jry}) + (compEPRICE_{jry} \cdot \%compSLSHPCT_{jry})$$

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

$regSLSHPCT_{jry}$ = the regulated proportion of sales to 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 actual competitive proportion of sales to customer class j in region r in year y

For supply regions with less than half of their electricity sales in competitive states, the EFP assumes regulated prices.

Each state with approved electricity deregulation plans has mandated electricity price reductions or freezes for a specified period of time. The extent of the mandates often differs by customer class (i.e. residential, commercial, industrial). The EFP has incorporated these mandates for each competitive region. With a mandated price reduction, the regulated electricity price (EPRICE) for the affected regions, years, and customer classes is decreased by the price reduction for those affected regions, years and customer classes, which has been weighted by the percentage of electricity sales affected by the price reduction With a price freeze, the electricity price for the affected regions, years and customer classes remains the same as it was at the time of the freeze for the specified number of months or years of the freeze. If the EFP pricing algorithm calculates higher regional prices in the affected years for the affected customer class, this freeze amounts to a price reduction. Weighted electricity price reductions for areas affected by price reductions and/or price freezes are calculated exogenous to the EMM and subtracted from the electricity price calculated by the EFP pricing algorithm for the affected region, year and customer class:

(5.3-32) $$\boldsymbol{EPRICE_{jry} = EPRICE_{jry} - weighted\ price\ reduction_{jry}}$$

where:

$EPRICE_{jry}$ = the nominal electricity price of customer class j in region r in year y

$weighted\ price\ reduction_{jry}$ = the electricity price reductions for customer class j in region r in year y as a result of price reductions and/or price freezes and as weighted by the percentage of kilowatt-hour electricity sales affected by the price reductions and/or price freezes -- calculated exogenous to the EMM.

Modifications for California:

As a result of the 2000-2001 electricity shortage, skyrocketing wholesale electricity prices, and the loss of credit by the major investor-owned utilities, the State of California started purchasing large amounts of electricity for the utilities through long-term contracts. The bulk of these contracts are to last 10 years. California also ended its retail competition program. Thus, starting

in 2002 and throughout the forecast period, NEMS assumes that most of the California electricity supply region will be regulated. An actual electricity price for the portion of California's load covered by long-term contracts was calculated through 2010. This calculation was based on the latest published average contract prices by customer class, year and percent of forecasted demand to be covered by contract prices. For most years this price was higher than the NEMS-forecasted regulated price. The difference between actual and forecast prices for the affected load amount was added or subtracted to the NEMS forecast price through 2010 so that:

(5.3-33) $$EPRICE_{jCAy} = EPRICE_{jCAy} + (CPRICE_{jCAy} - EPRICE_{jCAy}) \cdot percent\ of\ CA\ load\ under$$

where:

$EPRICE_{jCAy}$ = the nominal electricity price of customer class j in the California region in year y

$CPRICE_{jCAy}$ = the nominal average long-term contract electricity price of customer class j in the California region 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.

(5.3-34) $$GENTAX = EGTXRT \cdot ERRVLG + ERPRTX + ERSLTX$$

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 (e.g., investment tax credits, accelerated depreciation), this is not, in general, what is booked on the income statement as income tax expense.

(5.3-35)

$$CITAX = (ERRVLG - ERTFLN - ERTOMN - ERTDWO - GENTAX - (ERTIEX - AVDINT) - ESLLP) \cdot ESFTXR + STTAX - (ERFITC + XITCD) - (ERATSF + ERATSD)$$

where:

CITAX = current income taxes

ERRVLG = electric 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 which 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

Now, booked income tax expense is current taxes, plus deferrals, minus amortizations:

(5.3-36)

$$BKITAX = CITAX + (XITCD - ERAITC) + (ERXFDC - ERAFDC) + ERATSD - EREDTF$$

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):

$$\textbf{(5.3-37)} \qquad STTAX = (ERRVLG - ERTFLN - ERTOMN - ERTDWO - ERTIEX - ESLLP) \cdot ESSTXR \cdot (1 - ESFTXR)$$

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 forecasted 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:

1) 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.

2) 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).

3) AFUDC as a Percentage of Earnings Available for Common. This ratio is calculated AFUDC divided by earnings available for common equity.

4) Internal Cash Flow as a Percent of Construction Expenditures. This ratio is calculated as total internally generated funds divided by construction expenditures (excluding AFUDC).

5) Construction Work in Progress (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.

6) 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.

7) Safety Margin. This ratio is calculated as net income plus booked income taxes, minus AFUDC, all divided by electric revenues.

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Appendix 5.A. Data Sources

Utility Expenses

Utility costs and tax data come from four separate survey forms, depending on the type of utility. Data for investor-owned electric utilities come from the Federal Energy Regulatory Commission Form FERC 1, "Electric Utility Annual Report." Data for Federal power projects and municipal power authorities (publicly-owned) come from the Energy Information Administration Form EIA- 412, "Annual Electric Industry Financial Report". Data for rural cooperatives (publicly-owned) come from the Department of Agriculture, Rural Electrification Administration (REA) Form REA-7, "Financial Statistical Report" and Form REA-12, "Operating Report." In the *Annual Energy Outlook (AEO)*, the latest available survey data were used to forecast electricity prices.

Percent of Regional Load in States with Competitive Pricing

Information on which states have legislation or regulations in place to allow competitive retail markets can be found on the Energy Information Administration (EIA) website "Status of State Electric Industry Restructuring Activity" at the following site:

http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf

and is supplemented with updates from the most recent State legislation and regulatory commission orders

The amount of electricity sales within each of the NERC electricity regions used by EFP is found on Form EIA-861, "Annual Electric Power Industry Report." The latest available survey data were used to forecast electricity prices in the AEO.

Information to Calculate Frozen and Reduced Electricity Prices in Regions with a Transition-to-Competition Pricing Structure

This information was collected from legislation and regulatory commission orders in relevant states as well as the EIA web site "Status of State Electric Industry Restructuring Activity" cited above.

Appendix 5.B. Construction Work in Progress

For regulatory purposes, 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 (i.e., 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 upon 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 this, 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:

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 on line	Capacity Planning Model
ESLCP	Length (in years) of construction period (including first year of operation)	User
$ESCPRF_y$	Direct (i.e., 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	Percent of AFUDC/CWIP which receives offset treatment	User
	0 Remainder of CWIP (i.e., 1.0 - CWPPER) is not in rate base	
	1 Remainder of CWIP is 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:

Step 1 is to calculate the AFUDC rate. EFP simulates a pre-tax AFUDC rate. EFP calculates the pre-tax AFUDC rate as:

(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 below is the fraction of AFUDC representing debt costs.

(App5.B-2) $$ESWACD = TEMPD/ESAFDC$$

where:

ESWACD = fraction of AFUDC representing debt costs.

Step 2:

Step 2 is to calculate direct construction expenditures by year, in nominal dollars. This is done for each year y, where y ranges from the first year of construction (i.e., EBSYR - ESLCP + 1) to the first year of operation (i.e., EBSYR).

(App5.B-3) $$EBYCWP_y = EBPCAP \cdot EBPCST \cdot ESCPRF_y \cdot ESGNPD_y \cdot CAPESC_y \quad \textbf{for } y = (EBSYR - ESLCP + 1) \textbf{ to } EBSYR$$

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 on line

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:

This step includes calculation of the major CWIP-related accounts for each year y during the construction period. includes year by year: CWIP allowed in rate base, booked CWIP, booked AFUDC, and the AFUDC offset. Also calculated is the book value of the new plant.

CWIP allowed in rate base is calculated as:

(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 = Percent of AFUDC/CWIP which receives offset treatment: 0 if no AFUDC offset, and 1 if AFUDC offset.

Booked AFUDC in year y is calculated as:

(App5.B-5) $$AFUDC_y = (EBBCWP_{y-1} + 0.5\ EBYCWP_y)\cdot(1- CWPPER_y)\ ESAFDC_y$$

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. This 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:

(App5.B-6)

$$EBBCWP_y = 0$$

$$for\ y = EBSYR - ESLCP\ (i.e.,\ year\ before\ construction\ begins)$$

$$= EBBCWP_{y-1} + EBYCWP_y + AFUDC_y$$

$$for\ y = (EBSYR - ESLCP + 1)\ to\ EBSYR\ (i.e.,\ construction\ period)$$

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:

(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 on line is:

(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 on line January 1 of year EBBSYR. EFP can also simulate plants coming on line after January 1, using similar equations.

Step 4:

The fourth step 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 on line after 1986 that is not grand-fathered under the provision must capitalize interest during construction.

(App5.B-9)

$$EBASVL_y = 0$$

$$\text{for } y = EBSYR - ESLCP \text{ (i.e., year before construction begins)}$$

$$= EBASVL_{y-1} + EBYCWP_y + AVDINT_y$$

$$\text{for } y = (EBSYR - ESLCP + 1) \text{ to } EBSYR \text{ (i.e., construction period)}$$

$$= EBASVL_{EBSYR}$$

$$\text{for } y = EBSYR \text{ to } (EBSYR + ESBKLF) \text{ (i.e., during service life)}$$

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 on line and first year of construction. When the new tax law does apply, the capitalized interest is calculated as:

(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:

The fifth step is to calculate several accounts related to AFUDC. It is important to separate AFUDC into that financed by debt and that financed by equity:

(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. This is done by using the concept of the tax savings due to the debt portion of AFUDC.

(App5.B-12)

$$ERFFDC_y = ERFDCD_y \cdot ESFTXR \cdot ESFPDB$$
$$ERFXFDC_y = ERFDCD_y \cdot ESFTXR \cdot (1 - ESFPDB)$$
$$DAFDC_y = \sum_{i=K}^{y} ERXFDC_i$$
$$\textbf{for } y = K \textbf{ to } EBSYR$$
$$\textbf{where } K = EBSYR - ESLCP + 1$$

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 towards 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.

(App5.B-13)

$$EBAFDC = DAFDC_{EBSYR} / ESBKLF$$

$$DAFDC_y = DAFDC_{y-1} - EBAFDC$$

for $y = EBSYR$ to $(EBSYR + ESBKLF - 1)$ (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:

(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 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):

(App5.C-1) $$ERBDEy - (ERBKVL - EBABDE_{y-1})/(ESBKLF - (YEAR-EBSYR))$$

and

(App 5.C-2) $$EBABDE_y = \sum_{i-EBSYR}^{y} ERBDE_i$$

for y = *EBSYR* to *EBSYR* + *ESBKLF* - 1 (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 on line

$EBABDE_y$ = 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. This has the effect of removing the plant from the books.

Depreciation for Tax Purposes:

For tax purposes, depreciation is accelerated (i.e., 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 them in the later years, compared to the straight-line method.

There are three different options in EFP when determining tax depreciation rates: i) use those prescribed in the Tax Reform Act (TRA) of 1986; ii) use those prescribed in the 1981 Economic Recovery Tax Act (ERTA); or iii) use the sum-of-years digit 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 on line. The sum-of-years digit method is used for any asset that comes on line before 1981. Because the first two methods are the most applicable approaches, they are discussed below. [90]

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 on line and on what service life class the asset belongs. Most assets in EFP are depreciated over 15 years (some 10) under ERTA, and 20 years (some 15) under TRA. Then, for the remaining years of the book life, tax depreciation is zero.

(App5.C-3) $$ERTDE_y = EXTXRS_y \cdot (EBASVL - 0.5 \cdot EBDITC)$$

for $y = EBSYR$ **to** $EBSYR + ESBKLF - 1$ **(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:

(App5.C-4) $$ERTDWO_y = ESDEPR \cdot (EBASVL - 0.5 \cdot EBDITC)$$

for $y = EBSYR$ **to** $EBSYR + ESBKLF - 1$ **(i.e., during the service life of the plant)**

where:

[90] The approach for the sum-of-years digit method is identical to that described except that the tax base is not reduced by one-half the investment tax credit.

$ERTDWO_y$ = 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.

(App5.C-5) $$ERTDRG_y = ERTDWO_y \cdot (1 - ESFLPR) + ERTDE_y \cdot (ESFLPR)$$

$$\text{for y} = EBSYR \text{ to } EBSYR + ESBKLF - 1 \text{ (i.e., during the service life of the plant)}$$

where:

$ERTDRG_y$ = tax depreciation expense for regulatory purposes, year y

ESFLPR = percentage of tax savings due to 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 to 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:

(App5.C-6) $$ERATSF_y = ESFTXR \cdot (ERTDE_y - ERTDWO_y) \cdot ESFLPR$$

$$ERATSD_y = ESFTXR \cdot (ERTDE_y - ERTDWO_y) \cdot (1 - ESFLPR)$$

$$DAD_y = \sum_{i=EBSYR}^{y} ERATSD_i \quad \text{for y} = EBSYR \text{ to } EBSYR + ESBKLF - 1$$

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 due to 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 percent to 40 percent in 1987 and to 34 percent thereafter. One effect 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-percent marginal tax rate) and what will ultimately be paid under the 34-percent marginal rate is referred as excess deferred income taxes.

(App5.D-1)
$$EXCESS = \sum_{y=EBSYR}^{IYREDT} (ERTDE_y - ERTDWO_y) \cdot (ESFTXR_y - ESFTXR_{IYREDT})$$

These excess deferred taxes should be flowed through to the ratepayers. 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:

where:

EXCESS = total excess deferred income taxes

$ERTDE_y$ = depreciation expense for tax purposes, year y

ERTDWO = 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:

(App5.D-2)
$$EREDTF_y = 0.0 \quad \text{if } y < IYREDT$$
$$= EXCESS / REMLIF \quad \text{if } y \geq IYREDT$$

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 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.

(App5.D-3) $\boldsymbol{ERPRDF = DAD + DAFDC - EREDTF}$

where:

ERPRDF = provision for deferred income taxes

DAD = deferred income taxes due to 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 grand-fathered 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 (i.e., 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 grand-fathering.

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.

(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.

(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,

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 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:

$$SLBKVL = SLPROC - BKGAIN$$

$$SLGAIN = BKGAIN - SLTAXS \quad \textbf{(App5.E-1)}$$

$$SLASVL = SLPROC - SLTAXS \,/\, ESFTXR$$

where:

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 removed from utility plant in service and the tax basis is removed from the utility tax accounts. This 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. This has the effect of removing the plant from utility books.

The remaining quantities are now calculated:

(App5.E-2)

$$ESLPRC = SLPROC - SLTAXS$$

$$ESLLP = SLLP$$

$$ESLAGN = SLGAIN \;/\; SLTERM$$

$$ESLNDG_j = SLGAIN - j \cdot ESLAGN \text{ for } j = 1, SLTERM$$

$$ESLLPN = ESLLP - ESLAGN$$

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 on line 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 1980's and early 1990's, however, many situations have arisen where, under traditional regulation, substantial rate increases would occur as new plants come on line. This was 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. This is due to lower energy commodity prices as well as the power generation technologies leveling out in terms of efficiency. Additionally, many areas of the country were over-built with capacity, again lowering the savings derived from the new plants. In many cases, a single utility brought on line a new plant whose total costs made up 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 is followed by a number of years in which rates are higher than they would have been in order to allow the company to make up for the early years. After 2000, EFP forecasts 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:

$$\textbf{(App5.F-1)}\quad RR_y = \frac{PIBKVL\ (1 - DISPER)\ (1 - y/PIBKLF)\cdot ESPR/(1 - ESFTXR) + PIBKVL}{PIBKLF\ (1 + (1 - PITXBS)\cdot ESFTXR/(1 - ESFTXR)))}$$

$$\textbf{for y} = 1, LPI$$

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:

(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):

(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:

(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:

(App5.F-5)
$$EDISNT_y = PIBKVL \cdot DISPER \cdot (1 - y/PIBKLF)$$
$$\text{for } y = 1, PIBKLF$$

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).

Appendix 5.G. Functional Description Calculation of the Reliability Component

The subroutine ELREL calculates the reliability component of marginal cost in the competitive pricing routine. The basic idea is from "Incorporating Explicit Loss-of-Load Probability Constraints in Mathematical Programming Models for Power System Capacity Planning," by Sanghvi and Shavel. We describe the capacity and load distributions by means of their first four cumulants, and form the marginal capacity function from the sum of the cumulants. See "Kendall's Advanced Theory of Statistics," Fifth Addition, Kendall, Stuart and Ord. By taking the derivative of each of the cumulants, we then derive the marginal change in unserved energy.

In this model there are three seasons with 3 time slices per season to represent load and prices at various time periods within each year. The marginal expected unserved energy is calculated for each time slice independently. Rather than calculate the derivative of expected unserved energy, a differential approximates it to save computing time.

The marginal capacity function as the stochastic function is defined as:

(App5.G-1) $$M = G - L$$

where:

$L(l)$ = density function for load (demand), and

$G(g)$ = density function for generating capacity.

Unserved energy as the stochastic variable is defined as:

(App5.G-2) $$UE = \begin{cases} m, m < 0 \\ 0, otherwise \end{cases}$$

and expected unserved energy as:

(App5.G-3) $$EUE = \int_0^{Z1} m M_x(m) dm$$

where:

$$Z1 = \frac{[E(L) - E(G)]}{sdev}$$

−the normalized mean of the marginal capacity function. Since M_x cannot be integrated analytically, it is approximated numerically from its first four cumulants using the Gram-Charlier expansion.

First, the cumulants of the marginal capacity function are calculated as:

(App5.G-4) $$tdcum1(icm) = capcum1(ise, icm, RNB, 1) + dcum(sblk, icm, RNB)\ (-1)^{icm}$$

where:

tdcum1 = marginal capacity cumulant icm for the slice

capcum1 = capacity cumulant icm for season ise, region RNB

dcum = demand cumulant icm for slice sblk and region RNB

(App5.G-5) $$tdcum2(icm) = capcum2(ise, icm, RNB, 2) + dcum(sblk, icm, RNB)\ (-1)^{icm}$$

where:

tdcum2 = marginal capacity cumulant icm for the slice

capcum2 = capacity cumulant (with increment) icm for season ise, region RNB

dcum = demand cumulant icm for slice sblk and region RNB

Next, the standard deviation of the distributions is calculated:

(App5.G-6) $$sdev1 = \sqrt{tdcum1(icm)}$$

(App5.G-7) $$sdev2 = \sqrt{tdcum2(icm)}$$

and the normalized mean of the marginal capacity function. The subroutine DELEUE finds the change in margin unserved energy from these quantities.

The subroutine SHAVEL computes the Shavel/Sanghvi approximation to the cumulative distribution at a point z given its first four cumulants. This is based on the first few terms of the Gram-Charlier expression of a distribution as an infinite series of its cumulants and consists of the following equations:

(App5.G-8) $$g1 = \frac{cum3}{cum2^{1.5}}$$

(App5.G-9) $$g2 = \frac{cum4}{cum2^{2}}$$

The function NORM finds the cumulative normal probability distribution for any value z1.

(App5.G-10) $$norm0 = pinorm * \exp^{-\frac{z1^2}{2}}$$

(App5.G-11) $$call\ norm(z1, norm0, normx1)$$

(App5.G-12) $$cum = normx1 - \frac{g1 \cdot norm0 \cdot (z^2 - 1)}{6!} + \frac{g2 \cdot norm0 \cdot (3z - z^3)}{4!} + \frac{g1^2 \cdot 10 \cdot norm0 \cdot (10z^3 - 5z - z^5)}{6!}$$

where:

g1, g2	=	Gram-Charlier terms
z	=	z-value (input)
cap	=	size of the unit (Gigawatts)
cum1	=	first cumulant of marginal capacity function
cum2	=	second cumulant of marginal capacity function
cum3	=	third cumulant of marginal capacity function
norm( )	=	cumulative normal probability distribution for any value z1
pinorm	=	0.39894228040
cum	=	cumulative distribution (output)

(App5.G-13)

$$val3 = \sum_{i=1}^{5} b_i \cdot \left(\frac{1.0}{1.0 + a \cdot z1}\right)^i$$

where:

val3	=	intermediate value
b	=	constant
a	=	constant
z	=	z-value (input)

(App5.G-14)

$$cum = 1.0 - dens \cdot val3$$

where:

cum	=	cumulative distribution evaluated at z1, and
dens	=	normal density evaluated at z1.

The function DELEUE develops the contribution of a unit of capacity of a particular ECP type to the reduction in marginal expected unserved energy.

(App5.G-15)

$$G1 = \left(\frac{cum3}{cum2}\right)^{3/2}$$

(App5.G-16)

$$\begin{aligned} DELEUE \quad &= 0 + DZ1\,(\,for, cap, cum1, cum2\,) \cdot LOLP \\ &\quad - DG1\,(\,for, cap, cum2, cum3\,) + \frac{N2\,(z14\,)}{3!} \\ &\quad + \frac{DG2\,(\,for, cap, cum2, cum4\,) \cdot N3\,(z14\,)}{4!} \\ &\quad + \frac{2 \cdot G1 \cdot DG1\,(\,for, cap, cum2, cum3\,) \cdot 10 \cdot N5\,(z14\,)}{} \end{aligned}$$

where:

for	=	forced outage rate,
cap	=	size of the unit (Gigawatts),
cum1	=	first cumulant of marginal capacity function,
cum2	=	second cumulant of marginal capacity function,
cum3	=	third cumulant of marginal capacity function, and
cum4	=	fourth cumulant of marginal capacity function.

The function DZ1 creates the coefficient for the third order term of the approximation of marginal unserved energy function for the ECP.

(App5.G-17)
$$DZ1 = for\ \sqrt{cum2}\ \cdot .5\ (\cdot -1\ cum1)\ \cdot for\ (1-for)\cdot cap\cdot cum2^{-3/2}$$

where:

for	=	forced outage rate,
cap	=	size of the unit (Gigawatts),
cum1	=	first order cumulant of marginal capacity function, and
cum2	=	second cumulant of marginal capacity function.

The functions DG1 and DG2 create the coefficients for the second and fourth order terms, respectively, of the approximation of marginal unserved energy function for the ECP.

(App5.G-18)
$$DG1 = for\ cap^2\ (1-3\cdot for+2\cdot for^2)\ cum2^{3/2}\ -1.5\ cum3\ \cdot for\ cap\ (1-for)\cdot cum2^{-5/2}$$

(App5.G-19)
$$DG2 = for\ cap^3\ (1-7\cdot for+12\cdot for^2 - 6\cdot for^3)\ cum2^{-2}\ -2\ cum4\ \cdot for\ cap\ (1-for)\cdot cum2^{-3}$$

where:

for = forced outage rate

cap = size of the unit (Gigawatts)

cum2 = second order cumulant of the marginal capacity function

cum3 = third order cumulant of the marginal capacity function

cum4 = fourth order cumulant of the marginal capacity function

The functions N2, N3, and N5 create the coefficients for the second, third and fifth order terms for the approximation of marginal unserved energy for the ECP.

(App5.G-20) $$N2 \quad 1 - (z2^2 - 1.0) * pinorm * Exp(\frac{-z2^2}{2})$$

where:

Pinorm = 0.39894228040, and

z2 = mean of the marginal capacity function.

(App5.G-21) $$N3 \quad 1 - (z3^3 - 3 * z3) * pinorm * Exp(\frac{-z3^2}{2})$$

where:

pinorm = 0.39894228040, and

z3 = mean of the marginal capacity function.

(App5.G-22) $$N5 \quad 1 - (z5^5 - 10 * z5^3 - 15 * z5) * pinorm * Exp(\frac{-z5^2}{2})$$

where:

pinorm = 0.39894228040, and

z5 = mean of the marginal capacity function.