The Electricity Market Module of the National Energy Modeling System

Model Documentation Report

February 2001

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

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I. Introduction

The National Energy Modeling System (NEMS) was developed to provide mid-term (20 to 25 years) forecasts and analyses of energy-related activities. The NEMS Electricity Market Module (EMM) provides a major link in the NEMS framework (Figure I.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 then 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 system module, and capital requirements to the macroeconomic module. The model is iterated 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, and natural gas; 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 load and demand-side management (Figure I.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 I.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. Construction of generating plants with long lead times is selected with planning horizons up to ten periods into the future, although a six-year planning horizon is currently used. Electricity demand is represented by load curves, which vary by region, season, and time of day.

For the Annual Energy Outlook 2001, the EMM also represents distributed generation that is owned and operated 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 viewed as follows:

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

2. The electricity capacity planning submodule projects the construction of new generating, the retirement (if appropriate) of existing plants, the level of firm power trades, and the addition of scrubbers for environmental compliance.

3. The electricity fuel dispatch submodule dispatches the available generating units, both utility and nonutility, allowing surplus capacity in selected regions to be dispatched for another region's needs (economy trade).

4. The electricity finance and pricing submodule calculates total revenue requirements for each utility operation and computes average and marginal-cost based electricity prices.

Figure I.1. National Energy Modeling System
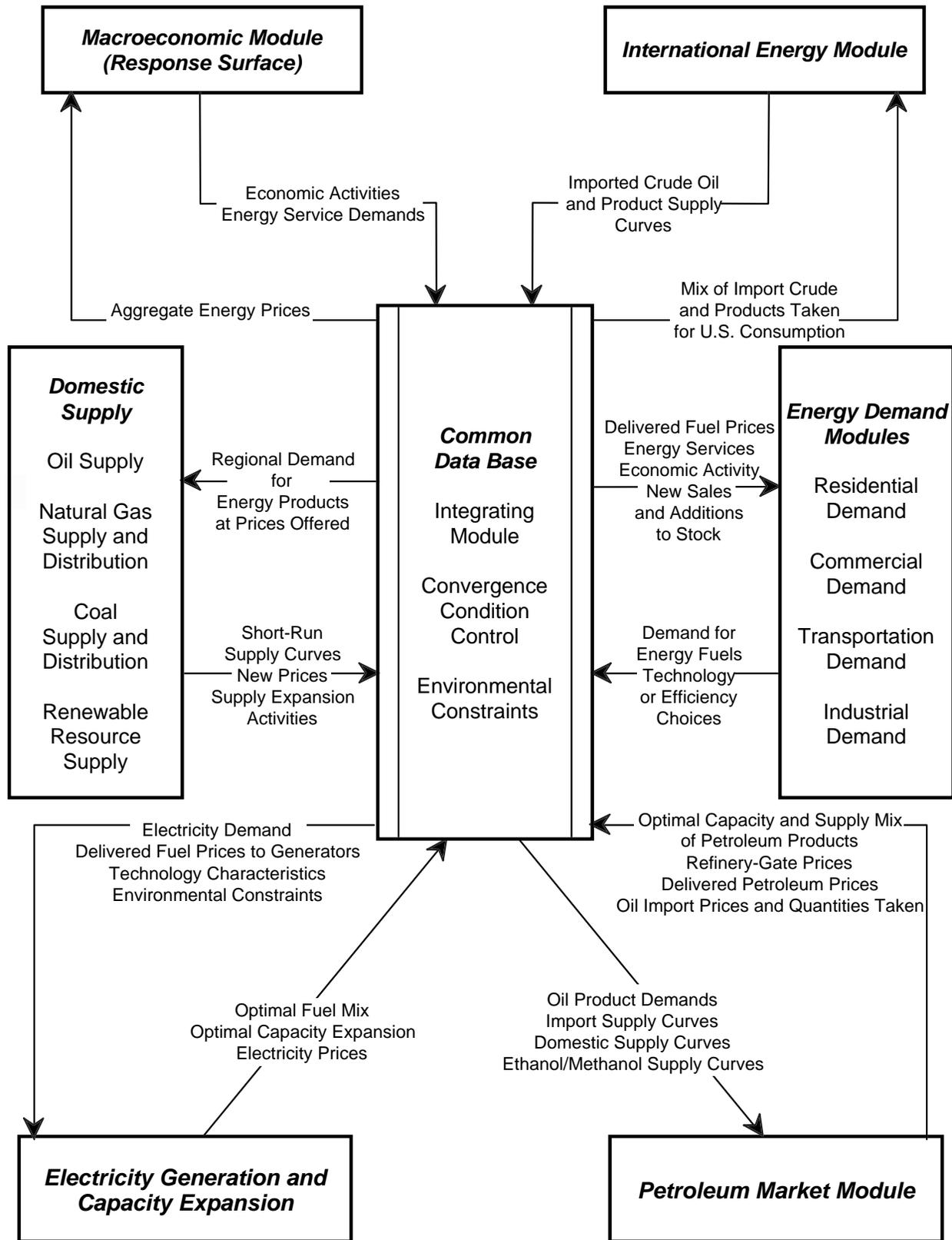
Figure I.2. Electricity Market Module Structure

Exogenous

Financial Data, Tax Assumptions, Capital Costs, Operating and Maintenance Costs, Operating Parameters, Emission Rates, Existing Facilities, New Technologies, Transmission Constraints, Hydropower Capacity and Capacity Factors

Electricity Market Module

N E M S

Demand Modules
- Expectations
- Electricity Sales
- Cogeneration Supply and Fuel Consumption
- Sales to Grid
- Electricity Prices

Natural Gas Transmission and Distribution Module
- Natural Gas Prices
- Natural Gas Demand
- Expected Future Demand
- Parameters on Demand in Dual-Fired Plants

Petroleum Market Module
- Petroleum Prices
- Petroleum Demands
- Electricity Price

Oil and Gas Supply Module
- Electricity Price

Coal Market Module
- Coal Prices
- Coal Demand

Renewable Fuels Module
- Renewable Technology Characteristics, Allowable Capacity, Capacity Factors, Costs
- Renewable Capacity, Avoided Costs, Discount Rate, Biomass Consumption

Macroeconomic Activity Module
- Interest Rates, Gross Domestic Product
- Electricity Prices
- Electric Industry Output

Electricity Capacity Planning Submodule

Available Capacity

Capacity Additions

Electricity Fuel Dispatch Submodule

Fuel Demands

Electricity Finance and Pricing Submodule

Average Electricity Prices

Load and Demand-Side Management Submodule

Load Curves

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 1.3. Electricity Market Model Supply Regions

1 ECAR   6 NY   11 NWP
2 ERCOT   7 NE   12 RA
3 MAAC   8 NE   13 CNV
4 MAIN   9 STV
5 MAPP   10 SPP
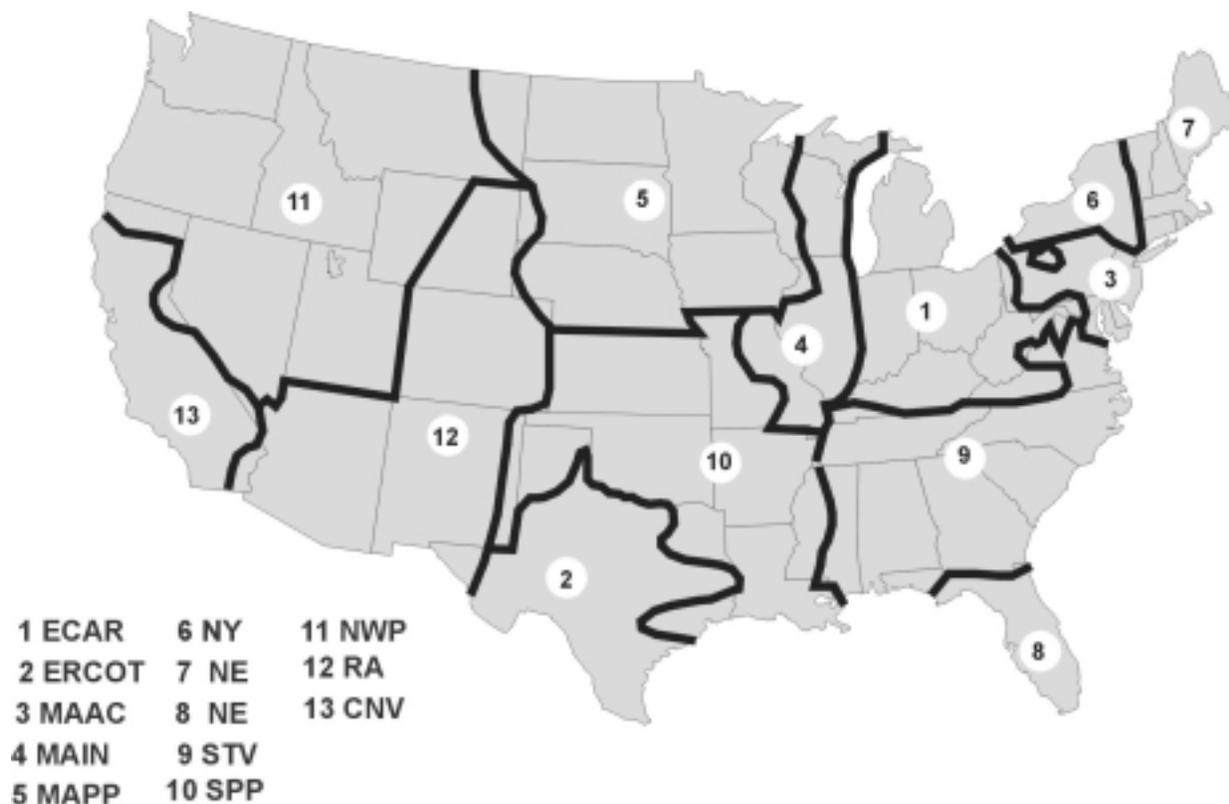
Electricity Capacity Planning Submodule

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. 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 expected utilization of the capacity is important in the decisionmaking 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).

Technologies are compared on the basis of total capital and operating costs incurred over a 20-year period. As new technologies become available, they are competed against conventional plant types. Fossil-fuel, nuclear, and renewable generating technologies are represented.

The timing of the demand increase is important, because the construction lead times of technologies differ. A multi period optimization is performed, whereby capacity choices in each year are made by looking several years into the future rather than a single year only.

Construction lead times also contribute to uncertainty about investment decisions. Technologies with long lead times are subject to greater financial risk. Compared to plants with shorter lead times, they are more sensitive to market changes in interest and inflation rates and are more vulnerable to uncertain demand projections that determine the need for new capacity. To capture these factors, the discount rate for each technology is adjusted using risk premiums based on the construction leadtime. The risk-adjusted discount rate results in the perception that a technology with a long leadtime is less economically attractive than another technology with similar costs, but a shorter leadtime.

Uncertainty about investment costs for new technologies is captured in the ECP using technological optimism and learning factors. "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." For new technologies, cost reductions due to learning also account for international experience in building generating capacity. Generally, overnight costs for advanced generating technologies are assumed to decrease by 10 percent for each doubling of capacity for the first through the fifth unit, by 5 percent for each doubling of capacity for the sixth through the fortieth unit, and by 2.5 percent for each doubling of capacity past the fortieth unit. In the case of conventional generating technologies, base overnight costs are assumed to be the current cost per kilowatt for a unit constructed today. Costs then decrease by 2.5 percent for each doubling of capacity. Some exceptions to this methodology are made where special circumstances occur, such as for wind.

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 competed using supply curves developed from cost estimates for potential hydroelectric projects in Canada. Imports from neighboring electricity supply regions are competed 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 following technologies are considered:

Fossil Fuel Fired	Nuclear
Coal without FGD pre-1965 Coal without FGD post-1965 Coal with FGD New pulverized coal with FGD Advanced clean coal technology Gas/oil steam Conventional gas/oil combined cycle Advanced combined cycle Conventional combustion turbine Advanced combustion turbine Fuel cells *(FGD = flue gas desulfurization)*	Conventional nuclear Advanced nuclear Distributed generation
	Renewables
	Conventional hydropower Geothermal Solar-thermal Solar-photovoltaic Wind Wood Municipal solid waste

Electricity Fuel Dispatch Submodule

Given available capacity, firm purchased-power agreements, fuel prices, and load curves, the electricity fuel dispatch (EFD) submodule 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 implemented for the *Annual Energy Outlook 2000* (AEO2000) version of the model allows a least cost optimization of plants based on their operating costs and any transmission costs. Limits on emissions of sulfur dioxide from generating units and the engineering characteristics 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. In addition, to account for scheduled and unscheduled maintenance, the capacity of each plant is derated (lowered) to the expected availability level. Finally, the annual operation of utility and nonutility plants for each region is separated into six time periods to reflect the seasonal variation in electricity demand.

Interregional economy trade 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 (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. 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 made available 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.

Load and Demand-Side Management Submodule

The load and demand-side management (LDSM) submodule generates load curves representing the demand for electricity. 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. For operational and planning analysis, an annual load duration curve, which represents the aggregated hourly demands, is constructed. Because demand varies by geographic area and time of year, the LDSM submodule generates load curves for each region and season for operational purposes.

Emissions

The EMM tracks emission levels for sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Facility development, retrofitting, and dispatch are constrained to comply with the requirements of the Clean Air Act Amendments of 1990 (CAAA90) and other pollution constraints. An innovative feature of this legislation is a system of trading emissions allowances. 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 level set by CAAA90, 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.

II. Load and Demand-Side Management Submodule

This chapter documents the Load and Demand-Side Management (LDSM) submodule of the EMM. The LDSM works in conjunction with the NEMS demand modules, and the capacity planning and dispatch modules of the EMM. The primary purpose of the LDSM submodule is to translate total electricity consumption forecasts into system load shapes needed for capacity planning and power plant operations. A secondary function of LDSM is to explicitly incorporate utility decision-making with regards to utility-sponsored DSM into the NEMS modeling framework.[1]

Broadly speaking, the LDSM submodule has been designed to perform four major functions:
- Translate total electricity consumption forecasts into system load shapes
- Develop utility DSM programs for potential inclusion in future utility capacity expansion plans
- Translate census division demand data into NERC region data, and vice versa
- Report DSM impact on regional system demand.

Model Objectives

The LDSM submodule is designed to be a fully integrated part of the NEMS framework. The submodule models the impact of DSM activities in terms of changes in load shapes. To do this, the LDSM submodule has a database of end-use load shapes for each of the thirteen EMM regions, being modeled in the NEMS framework. The LDSM also uses a technologies database developed jointly with the demand modules. Individual DSM options then match a base technology ("FROM" technology) to a more efficient DSM technology ("TO" technology). The energy changes and the resulting changes in load shapes (delta load shapes) are computed for each option. These constitute the unit level impact of DSM options. To compute the system level impacts, the DSM options must first be penetrated over time, and then aggregated to a form that can be competed against supply-side options. Details of these processes are given in the sections that follow.

The LDSM submodule uses stock and demand information from the demand modules at a Census Division level, and translates it into EMM region level data. The LDSM has a developed database of DSM options in the residential and commercial sectors.

Using this information, the LDSM models potential changes in stock and energy consumption patterns, as a result of utility sponsored rebates, and informational DSM programs. The effect of these DSM programs is modeled in terms of changes in the load duration curves. Before these potential changes can be included as final stock changes, however, they must be selected by the ECP module, after competing against supply-side options. Thus the LDSM module pre-screens DSM options that are then sent to the ECP for final evaluation. The DSM options that are finally chosen, are then translated into changes in stock. These stock changes are then passed on to the demand modules for computation of the new stock figures.

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[1]The algorithms within the LDSM representing utility-sponsored DSM programs have not been updated in recent versions of the model, and they would require significant work before they could be used. Utility expenditures on these programs have been declining in recent years, and it is felt that their impact is adequately captured in the efficiency trends seen in the NEMS demand models.

Level of Aggregation

In the LDSM, electricity generation is represented for 13 North American Electric Reliability Council (NERC) Regions and Subregions, called EMM regions. Of the 9 NERC Regions, six are represented in their entirety: ECAR, MAAC, MAIN, MAPP, SPP and ERCOT. In the Northeast Power Coordination Council (NPCC), the New England states constitute one region and New York represents another (NY). In the Southeastern Electric Reliability Council (SERC), Florida is separated from the rest of the region. The Rocky Mountain Power Area (RMP) and Arizona-New Mexico Power Area (AZN) Subcouncils have been combined into one region. The Northwest Power Pool Area (NWP) and California-Southern Nevada Power Area (CNV) form the other two regions.

Using NERC Regions and Subregions allows for a better representation of electricity markets. Load data for electric utilities is collected by the NERC and only provided at the regional level. These data are not easily separable into census divisions because many utilities operate across state boundaries. Thus, the present structure makes comparisons of EIA and NERC forecasts possible at a regional level instead of just the national level.

Relationship to Other Modules

The LDSM submodule interacts with the NEMS demand modules, and the ECP, EFD, and EFP submodules within the EMM. Hence, the LDSM is directly linked with several major modules in the NEMS modeling framework. Figure II.1 displays these linkages. Only the LDSM links are shown in the figure.

There are two central sets of linkages associated with the LDSM module:
* Inter-Module, i.e., with the Demand Module
* Intra-Module, i.e., with the other submodules of the EMM.

Although the LDSM works independently of these other modules, the LDSM shares common data and provides necessary data for these modules.

Figure II.1. LDSM Linkages With Other Modules

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                    ┌─────────────────────┐
                    │                     │
                    │   EFD Submodule     │
                    │                     │
                    └─────────────────────┘
                              ▲
                  Adjusted System Load Duration Curves
                      (All Iterations, All Years)

                                            Projected System Load Duration Curves (LDC)
                                                     DSM Program Costs
                                                   DSM Program LDC Impacts
                                                    (One Iteration Each Year)
            DSM Participation Levels                 (Optionally All Iterations)

┌──────────────────┐      ┌──────────────────┐      ┌──────────────────┐
│                  │      │                  │      │                  │
│  NEMS Demand     │      │     LDSM         │      │  ECP Submodule   │
│   Modules        │      │   Submodule      │      │                  │
└──────────────────┘      └──────────────────┘      └──────────────────┘
   Efficiency Level              ▲  ▲  ▲          Selected DSM Program Avoided Costs
  Electricity Demand
  Stock Information

                                      DSM Costs
              Electricity Rates   Sectoral Peak Contribution

                    ┌─────────────────────┐
                    │                     │
                    │   EFP Submodule     │
                    │                     │
                    └─────────────────────┘
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Intra-Module Data Linkages

The LDSM submodule is designed to be fully linked with the other EMM submodules. The LDSM submodule performs four integrating functions. The first integrating and linkage function is to supply system load duration curves to the Electricity Capacity Planning (ECP) and the Electricity Fuel Dispatch (EFD) submodules. The second key linkage function is to develop economic DSM programs (costs and load shape impacts) for consideration by the ECP submodule and to process the DSM options that are selected by the ECP. The third key linkage is the passage of avoided cost values from the ECP and electricity rates from the Electricity Finance and Pricing (EFP) to the LDSM submodule. The LDSM in turn, passes DSM program costs, and peak contribution information for each end-use sector, to the EFP module that are used to modify the financial statements and develop cost allocation algorithms. The fourth linkage function is to develop adjusted system load duration curves that account for DSM for the EFD. Current LDSM code is equipped with the designated INCLUDE files which contain common blocks for accomplishing the aforesaid linkages.

Table II.1 lists the major linkages between the LDSM and the other EMM submodules. Table II.1 and Figure II.1 show that the LDSM interacts with the other EMM submodules before and after they are run. The following subsections discuss intra-module linkages in greater detail.

Table II.1. LDSM Intra-Module Linkages

EMM Submodule	Inputs to LDSM from Submodule	Outputs from LDSM to Submodule
ECP	• Selected DSM Programs • Fraction of implementation of the selected programs • Avoided Costs	• Projected System Load Duration Curves • DSM Programs • Delta Load Impacts • DSM Costs (Equipment and Program) • Maximum Possible DSM Penetration
EFD		• Yearly Adjusted Regional System Load Duration Curves
EFP	• Electricity Rates	• Utility DSM Investment

Linkages with the Electricity Capacity Planning Submodule

The LDSM submodule has numerous linkages with the ECP submodule. The following discussion is divided into the outputs and inputs to the LDSM submodule.

Outputs

The outputs from the LDSM submodule to the ECP include:
• Projected Regional system load duration curves for each year in the ECP planning horizon
• Potential DSM programs, in aggregated form.

In each yearly iteration of NEMS, the LDSM obtains projections of yearly demand data from the demand modules. The Demand modules produce electric demand estimates on a Census Division level. The LDSM converts these data from a Census Division level 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 matrices do not change over time). Utilizing these forecasts, the LDSM develops system load shapes for each of the 13 EMM regions.

These system load shapes are then discretized to obtain load duration curves (LDCs), that are input to the ECP submodule. The LDSM 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. The ECP submodule develops these load shapes for future years based on projected future electricity demand. The shape of these LDCs for future years is either fixed or variable, depending on the foresight assumptions. Under perfect foresight, the system load shape and LDC change for each future year based on end-use demand patterns. Conversely, under both the myopic and adaptive expectations scenarios, the system load shape and LDC are scaled, based on total electricity demand, but keep the same pattern for future years.

In each yearly iteration of NEMS, the LDSM also develops aggregate DSM programs, for each EMM region for possible selection by the ECP submodule. Examples of aggregate DSM programs that might

be passed to the ECP submodule for examination include space heating, space cooling, and lighting. The DSM programs that are output to the ECP by the LDSM are aggregate (i.e., multiple DSM options) programs that have already passed the prescreening test. The California Total Resource Cost (TRC) test as used by the California Public Utility Commission (CPUC) in 1987, and an alternative test, the Rate Impact Measure (RIM) test are used by the LDSM. The TRC test compares the total customer direct costs of an option to the utility benefits of reduced demand and energy. The RIM test, designed to better represent DSM measures in the competitive market environment, tests options from the perspective of the electric utility. More details on the tests are given in later sections. The ECP selects the least-cost mix of resource options based on data on DSM, supply and renewable options. In effect, the DSM programs become "capacity" resources which are characterized by associated implementation and operating costs and which can be used to satisfy a portion of electricity demand in each load segment.

The specific DSM program data output to the current version of the ECP submodule are the following:
- **Potential DSM Impacts on LDCs.** These load duration curve impacts incorporate market penetration assumptions based on rebate levels, payback acceptance curves, and linear growth from current to maximum penetration levels.
- **DSM Costs.** Total utility DSM costs in present value terms, for each DSM program.[2]

Inputs

The LDSM receives three inputs from the ECP submodule:
- **Regional Avoided Costs**
- **Selected DSM Programs**
- **The Fraction** of the selected DSM programs that the ECP Submodule decides to implement in the next year, expressed as a value between 0 and 1.

These inputs are described below.

Key inputs to the LDSM are forecasts of regional avoided costs derived by the ECP submodule. These avoided costs, are based on the marginal cost of producing more electricity, in case DSM measures are not promoted, and electricity consumption increases as a result. In regions where there is already surplus built capacity, the marginal costs are only the variable costs, mostly fuel cost. However, in regions where new capacity needs to be built in order to meet growth in consumption, the avoided costs include the cost of building new capacity. Hence, avoided costs in those regions are larger. It is, therefore, more beneficial for utilities in regions with high avoided costs to promote DSM measures, than it is for utilities in regions with lower avoided costs. Avoided costs are thus used to screen DSM options. Avoided cost projections are needed for each future year and LDC segment.

After the ECP submodule chooses economic DSM programs, and the level of implementation expressed as a function of the maximum possible penetration of the market, the LDSM processes the selected programs prior to passing participation levels to the NEMS demand modules, and utility DSM costs to the EFP submodule. The key function that the LDSM conducts after the ECP module is executed is to disaggregate the aggregated DSM programs into the more detailed DSM options. Tables A1 through A3 in Appendix II-A give some idea of the aggregated DSM programs and the disaggregated DSM options that are likely to be used in the LDSM submodule.

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[2]These present value annual costs are the sum of DSM investment costs (i.e., initial program costs) and annual utility program costs, such as utility rebates and incentives.

Linkages with the Electricity Fuel Dispatch Submodule

During each iteration of the NEMS model, the LDSM outputs regional LDCs to the EFD submodule. The curves used in the current version of the model, reflect demand impacts associated with conservation based DSM options only. These are incorporated into the electricity demand estimates created by the NEMS demand modules.

Linkages with the Electricity Finance and Pricing Submodule

The final intra-module LDSM linkage is with the EFP submodule. The EFP submodule develops estimates of utility revenue requirements, financing needs, and electricity rates based on capacity expansion decisions, fuel prices, and electricity demand. The LDSM provides outputs to the EFP submodule, and requires inputs from the EFP.

Outputs

After DSM programs are chosen by the ECP submodule, this information is passed on to the LDSM submodule. The LDSM interprets this information, and calculates the market impacts of these DSM options. This information is expressed as a fraction of the current market for different technologies, and is passed on to the demand modules by the LDSM. Based on current estimates of the market sizes, the demand modules estimate the new mix of technologies in the market, expressed in absolute numbers. These estimates are then returned to the LDSM.

Using this data, the LDSM develops utility costs (e.g., incentives, administration costs) incurred in each NERC region and demand sector. These program costs are output to the EFP submodule to incorporate into utility expenses and capital expenditures.

Inputs

In order to develop estimates of rebates, the LDSM requires forecasts of customer electricity rates. These regional electricity rates are used to calculate the payback associated with each DSM option. Rebates will be set in LDSM to achieve a 2-year customer payback. This 2-year payback criterion is based on standard utility practice, along with information derived from a survey of utility DSM programs. The survey was conducted by ICF Resources as a part of this project. Its primary function was to get a picture of actual DSM programs offered by utilities, as well as the level of costs incurred and incentives offered. The survey revealed that a 2-year payback criteria is used by many utilities in their DSM planning.

Linkage Example

Let us assume, that in the New England EMM region the LDSM submodule is gauging the effectiveness of a DSM program offering incentives on the purchase of more efficient refrigerators. Assume further, that the program is in the residential sector, and is aimed at existing households only. The LDSM has the incremental cost of the more efficient refrigerator. The LDSM needs the electricity rates in the EMM region, in order to compute what would constitute a 2-year payback for the customer. Based on the amount of savings needed for a 2-year payback, and the incremental costs of the more efficient refrigerator, the LDSM will be able to compute the level of rebate that the utility can offer for that DSM option.

Accordingly, the LDSM makes changes in the system load shapes and the LDCs, to reflect the reduction in refrigerator load as a result of the program, provided that the program is selected by the ECP submodule. Once these changes have been made, the costs incurred in the program must be recovered in the region's revenue requirement. Thus the costs of the program to the utilities of that

region must be passed on to the EFP submodule, which then includes them as expenses in the appropriate category of the revenue requirements of the region.

Inter-Module Data Linkages

There are three linkages of the LDSM with the NEMS demand modules. First, the LDSM transforms Census Division electricity 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. Second, the demand submodules transfer and share information on technology characteristics (electricity usage and costs) and market size with the LDSM submodule. As electric technologies and usage patterns change over time, the demand modules transfer data conforming to these changes, to the LDSM submodule. The LDSM is designed to directly access the technology characteristics database for each demand module. Third, after the EMM submodules choose economic DSM programs, the LDSM submodule translates program information into participation levels for the NEMS demand modules. The demand models transfer and share information about technology characteristics and market size with the LDSM. The LDSM accesses a technology characteristics database in each demand module.

Table II.2 lists the linkages between the LDSM and the other modules. Examination of this table and Figure II.1 shows that the LDSM interacts closely with these other modules during NEMS model runs. The following discussion highlights these inter-module linkages in greater detail.

Table II.2. LDSM Inter-Module Linkages

NEMS Module	Inputs to LDSM from Module	Outputs from LDSM to Module
Residential Demand Module	• UECs and current stock data, by equipment type • Equipment investment and operating costs • Electric demand by region and end-use	• Participation Shares by Equipment and Efficiency Levels
EFP Commercial Demand Module	• UECs and current stock data, by equipment type • Equipment investment and operating costs • Electric demand by region and end-use	• Participation Shares by Equipment and Efficiency Levels

Linkages with the NEMS Demand Modules

The LDSM Submodule is fully linked with the demand modules in NEMS. This complete linkage is necessary because the development of total system load shapes for the ECP and the EFD, and DSM programs for the ECP depends on detailed data on the level and characteristics of regional electricity demand. Since the linkage categories are similar between the LDSM and the two demand modules, this

section presents all of these linkages in total. In addition, the following discussion is divided into the inputs and outputs to the LDSM submodule.

Inputs

The inputs to the LDSM submodule from the demand modules include:

- UECs and current stock data, by equipment type
- Equipment investment and operating costs
- Electric demand by region and end-use

In each yearly iteration of NEMS, the NEMS demand modules develop regional (9 Census division levels) electricity demand for each of the end-uses. The LDSM first translates the Census Division estimates into EMM regional electricity demand. Next, the LDSM develops total EMM region system load shapes from the end-use demand estimates. The load shape development process is discussed below.

In order to support the other major demand-related function of LDSM, i.e., the development of DSM programs, the LDSM submodule requires inputs on the end-use technologies. The LDSM and the NEMS demand modules share the same basic data on technology cost and performance. This is important, since DSM activities promote energy efficient technologies that are already commercially available, or are likely to be available. Hence, these technologies must form a part of the technology stock for that particular year, in the demand submodules. The role of DSM is to bring about faster penetration of already existing technologies. If the same data base is not used by the demand submodules and the LDSM, there will be a divergence with respect to the technology assumptions that are being made by the demand submodules, and those being made by the LDSM. In keeping with these requirements, a joint data base has been developed by the LDSM and demand submodules.

The promotion of certain energy efficient technologies through DSM is based on two key attributes of the technologies, namely: (1) the incremental demand and load impact and (2) the incremental cost to achieve greater efficiency or load control.

Outputs

The outputs from the LDSM submodule to the NEMS demand modules are associated with the results of the DSM selection process conducted in the ECP submodule of the EMM. The ECP chooses "economic" DSM programs for future years. The LDSM translates size and characteristics of the DSM programs selected for the next year, into Census division equipment participation levels for input into the NEMS demand modules. These participation levels are expressed as fractions of available market. They indicate both, what technology gained participants and what technology lost participants. This function is performed over time, since a DSM program that has been selected will be implemented over a period of years. The LDSM also has the capability of outputting to the demand modules specific portions of the end-use equipment markets that will implement the DSM option. In other words, if a DSM program is being implemented over a period of five years, and has a potential market of 100,000 customers, the LDSM submodule allocates potential customers to the program over the five year period, such that the total number of customers is 100,000.

Model Overview and Rationale

Philosophical and Theoretical Approach

Increasingly stringent regulations, and a greater emphasis on the preservation of the environment, have in recent years, made it increasingly difficult for utilities to add to their generating capacity. On the other hand, the excess capacity that had been built into the system in the sixties and early seventies, has been gradually eroded as a result of increases in demand. Consequently, state and local governments, as well as utilities have sought ways to reduce the need for new generation sources, by modifying the ways in which electricity is used in the country. Most state commissions now require that utilities review all possible options, including DSM, in their plans to meet consumer demand. It is therefore logical, that the NEMS framework include a system for modeling DSM activities as an alternative to supply side options.[3]

Traditionally, several supply options are competed against each other when planning new generating capacity. However, DSM measures focus on individual end-uses or appliances, while generating capacity must be planned on the basis of aggregated demand and supply estimates. In order to allow DSM measures to compete against supply options, therefore, both demand and supply-side options must be expressed in terms that are comparable. The LDSM submodule follows such an approach.

The LDSM develops system load shapes for the thirteen EMM regions. These are used by the ECP submodule for capacity planning. Selected DSM programs are represented as changes in load duration curves, and competed against supply side options.

The LDSM has a database of DSM options in the residential and commercial sectors. The option database contains individual DSM options that map a "baseline" technology to a "DSM" technology. The baseline technology consumes more energy or else is characterized by a less economical pattern of energy usage over a 24 hour period, than the DSM technology. The energy savings resulting from the replacement of one unit of "baseline" technology with one unit of DSM technology are represented as delta load duration curves. Each curve consists of a predetermined number of load blocks characterized by different avoided costs.

The cost of energy saving is then compared against the LDC block specific avoided costs of electricity production for that region. These avoided costs are obtained from the ECP submodule of the EMM. Using criteria in the form of the Total Resource Cost (TRC) test or alternatively the Rate Impact Measure (RIM) test, all DSM options are pre-screened inside the LDSM submodule. Only those options that pass the test are developed further. Hence it is assumed that only those DSM measures whose cost of energy savings compares favorably with the avoided cost of electricity production, would be promoted by a utility.

For each successful DSM option, the DSM technology must then be "penetrated" into the market depending on the existing market share of the base and DSM technologies in the years over which the DSM program is offered. The market shares for the different technologies are obtained from the respective demand modules (residential or commercial).

These options are then aggregated into DSM programs. The energy savings accruing from these programs and the associated program costs on a regional level, are then passed on to the ECP

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[3]The algorithms within the LDSM representing utility-sponsored DSM programs have not been updated in recent versions of the model, and they would require significant work before they could be used. Utility expenditures on these programs have been declining in recent years, and it is felt that their impact is adequately captured in the efficiency trends seen in the NEMS demand models.

submodule for competing against supply side options. The DSM programs finally chosen as a result of this competition in the ECP submodule are then transferred back to the LDSM submodule where they are disaggregated into individual DSM options. Once this is done, the resulting changes in stock are computed, aggregated to the appropriate census division level, and passed on to the respective demand modules. In this manner, the LDSM submodule uses DSM measure information at the level of individual appliances, and combines it with aggregated demand and avoided cost information, in order to produce DSM programs that can be competed against supply side options. The final choice of DSM programs is made by the ECP submodule, and is then translated into changes in stock, which are executed by the demand modules.

Fundamental Assumptions

There are several implicit assumptions about DSM activities that have been made in the model design. First, the database of technologies used by the LDSM submodule for the residential and commercial sectors, assumes that these technologies are available throughout the U.S. at costs that are comparable. The model makes inherent assumptions about the commercial availability of energy efficient appliances in the future. The dates when these appliances will become available, their estimated capital and maintenance costs, as well as efficiencies are assumed inside the joint technology database.

Second, the model chooses the TRC or the RIM test for the pre-screening of DSM options. The general concept of the tests is that only the options with sufficiently high ratios of economic benefits to costs are accepted. The annual benefits are calculated as the sum of the products of energy savings times the avoided costs of meeting the demand. In the TRC test, the costs include the incremental costs of purchasing of the appliances and the administrative costs of implementing the option. However, using the RIM test, the costs include the revenue losses due to DSM implementation, administrative costs of implementing the option, and the cost of incentives paid to the participants. Both the benefits and the costs are appropriately discounted and summed over the entire technical life of the affected equipment. It is assumed that these tests are the two preferred test criteria used by utilities across the country in assessing the financial viability of their DSM programs, and that only financially viable DSM programs are promoted by utilities. As a possible exception to this rule, in the future, the model may have the provision for hardwiring some DSM programs as "must run" programs mandated by state governments and utility commissions.

The last assumption relates to the aggregation and disaggregation of individual DSM options, into DSM programs. When the ECP submodule chooses a fraction of a DSM program, it is assumed that the same fraction of each DSM option has been chosen, and the penetration of individual options is handled accordingly.

Model Structure

The three primary functions of the LDSM submodule are to (a) develop regional system load duration curves from demand estimates for the ECP and EFD modules, (b) screen potential DSM options for analysis by the EMM Capacity Planning module, and © supply the demand modules with feedback from the ECP concerning the shifts in end-use technology resulting from the optimal choice of DSM options. In addition to these three functions, the LDSM also translates the 9 Census division electricity demand estimates into the 13 NERC regions and subregions that the EMM requires.

The LDSM submodule is designed to simulate the DSM planning efforts at electric utilities. Furthermore, the LDSM will provide the bridge between demand forecasting and utility resource planning. For each yearly iteration, the demand models provide the integrating module with the total electricity demand by region for the current year, along with demand by end-use, building type and technology type. This information identifies the size of the potential market for utility-sponsored DSM programs. Naturally

occurring customer-driven energy efficiency changes are modeled by the demand models and serve as input into the DSM market penetration estimation procedure. Central to the question of naturally occurring efficiencies versus DSM induced efficiencies, is the issue of free riders, i.e., what proportion of DSM customers would have shifted to more efficient technologies even in the absence of DSM programs. Later sections touch upon this issue in more detail, since assumptions about free ridership play a big role in the cost effectiveness of a DSM program.

The Integrating Module also obtains forecasts of future electricity demand from the demand modules by end-use, building type and technology type. These forecasts are used by LDSM in developing system load shapes for the ECP submodule and for projecting DSM market penetration. The development and screening of DSM programs is conducted by LDSM. Actual choice of DSM programs as part of future utility resource plans is made by the ECP submodule.

Figure II.2 displays the sequence of tasks that LDSM conducts during each yearly iteration of the NEMS model. These tasks include:

- Mapping of Census Region Demand Estimates into EMM Regions
- Development of System Load Shapes
- Screening of DSM Options
- Computations of the DSM load impact curves and program lifetime costs
- Computation of sectoral peak loads necessary for the ECP module calculations
- Disaggregation of Selected DSM Programs
- Computation of the annual expenditures of utilities on DSM programs

This section summarizes the approaches to accomplish these tasks within the LDSM. The subsections that follow discuss each of these tasks in order.

Mapping of Demand Estimates into EMM Regions

One of the functions of the LDSM 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. Secondly, the LDSM will need to translate any DSM programs impacts back into the Census Divisions in the form of percentages of available market that has to be subjected to the technology shifts.

Figure II.2. LDSM Tasks

```
┌─────────────────────────────┐
│      Regional Mapping       │
└─────────────────────────────┘
               │
               ▼
┌─────────────────────────────┐
│      System Load Shape      │
│        Development          │
└─────────────────────────────┘
               │
               ▼
┌─────────────────────────────┐
│    Intermittent Technology  │
│    Load Shape Development    │
└─────────────────────────────┘
               │
               ▼
┌─────────────────────────────────────────────┐
│  DSM Screening:                              │
│   - Development of DSM Option Set            │
│   - Calculation of Incremental Costs and Impacts │
│   - Customer Payback Estimation              │
│   - Penetration Estimation and Rebate Derivation │
│   - Cost-Effectiveness Calculations          │
│   - DSM Program Aggregation                  │
│   - DSM Delta Load Shapes                    │
└─────────────────────────────────────────────┘
               │
               ▼
      *ECP and EFD Submodules*
               │
               ▼
┌─────────────────────────────┐
│      Disaggregation of      │
│        DSM Programs         │
└─────────────────────────────┘
               │
               ▼
       *NEMS Demand Modules*
```

Development of System Load Shapes

This section describes the methodology used to construct electric utility load curves in the LDSM. 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 LDSM 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 different results at different times of the day, and at different times of the year. The impact of energy efficiency improvement type 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 LDSM 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 to predict their customers' demand patterns. The hourly system load curves are developed by these utilities, from the bottom up. 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 curve. This may be because the end-use load curves do not conform to the actual usage pattern in the region. 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 LDSM will take advantage of such information as it becomes available.

There are two different approaches used within the LDSM 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 forecast. 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 calculating the hourly loads for an end-use, the LDSM 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 LDSM from the NEMS demand models. The typical load shapes for each end-use are an exogenous input to LDSM. 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 LDSM submodule's pre-processor, LSRDBMGR. Computing end-use normalized, hourly load profiles from the end-use inputs is a three step process. Figure II.3 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 LDSM come from the RELOAD database.

Figure II.3. Steps in the Computation of End-Use Hourly Loads

```
┌─────────────────────────────────┐
│      End-Use Annual Load        │
└─────────────────────────────────┘
                 │
                 ▼
┌─────────────────────────────────┐
│      End-Use Monthly Load       │
│   (Monthly Allocation Factors)  │
└─────────────────────────────────┘
                 │
                 ▼
┌─────────────────────────────────┐
│       End-Use Daily Loads       │
│       (Seasonal Day-Type        │
│        Allocation Factors)      │
└─────────────────────────────────┘
                 │
                 ▼
┌─────────────────────────────────┐
│      End-Use Hourly Loads       │
│    (Hourly Allocation Factors)  │
└─────────────────────────────────┘
```
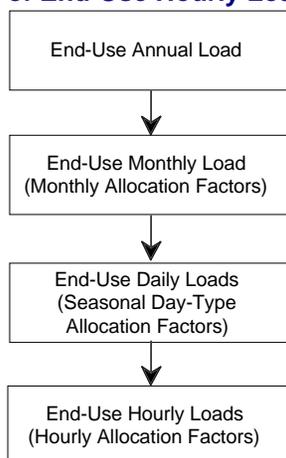
The first step is to divide the annual sales forecast into a set of monthly sales forecasts. This is accomplished based on a set of exogenous input monthly allocation factors. The monthly allocation factors are a set of weights assigned to each month. These weights inform the LDSM submodule of the relative 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. This technique is valid as long as the sum of the monthly weights is 100. Regardless of the technique by which the user assigns these monthly allocation factors, LDSM will use them to allocate annual load to monthly load.

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 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 is discussed below.

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,

$$DMNF = \sum_{m=1}^{NM} DMAF_m$$

Where:
DMNF   =   the normalization factor for monthly allocation
NM   =   the number of months in the forecast year
DMAF$_m$ =   the monthly allocation factor for month m (input)

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

$$DNMAF_m = \frac{DMAF_m}{DMNF}$$

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 used, 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:

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

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,

$$DDNF_m = \sum_{t=1}^{NDT} DWDAF_{mt}$$

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,

$$DNDAF_{mt} = \frac{DDAF_{mt}}{DDNF_m}$$

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.

$$DDTL_{mt} = DNDAF_{mt} \times DNMAF_m$$

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 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,

$$DHNF_{mt} = \sum_{h=1}^{24} DHAF_{mth}$$

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,

$$DNHAF_{mth} = \frac{DHAF_{mth}}{DHNF_{mt}}$$

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,

$$DHL_{mdh} = DNHAF_{mth} \times DDTL_{mt}$$

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:

$$\{DHL_{mdh} \text{ such that } m = 1, 2, ...NM; \ d = 1, 2, ...ND_m; \ h = 1, 2, ...24\}$$

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 LDSM model refers to the values on each record using the hour-in-the-year index as explained below.

$$DistLo = DHL_{mdh}$$

Where:

DistLo(H) = fraction of annual load allocated to hour H of a year

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:

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

Where:

SYLOAD(H) = system load in hour H

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. 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.

In LDSM, 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 LDSM 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 LDSM 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:

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

Where:

SYLOAD(H)	=	system load in hour H
$load2_e$	=	difference between the end-use's e 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 load shapes for end-uses
$DistLo_S(H)$	=	historical hourly load shapes for the system
NUSES	=	number of end-uses

While:

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

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 is specified as input data to the program.

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.

DSM Screening

The purpose of this component is to simulate utility DSM planning processes.[4] The design of DSM programs and the evaluation of program cost-effectiveness is a specific and separate electric utility task. Within a utility, forecasting personnel develop estimates of market size and composition and system planning personnel develop future resource plans. The LDSM maintains this separate structure.

The DSM Option Screening component simulates the DSM planning process by conducting the following tasks:
• Development of set of potential DSM options
• Calculation of incremental costs and impacts associated with DSM options,
• Calculation of simple customer payback
• Estimation of market penetration and rebate levels
• Calculation of DSM option cost-effectiveness, and
• Aggregation of cost-effective DSM options into DSM program categories.

The output of this component is a set of DSM programs that are characterized by total utility cost and load shape impact in LDC format. These outputs for each aggregated DSM option are used in the ECP submodule to select future resources. The following sections describe the steps that are performed in the DSM option screening component of the LDSM.

Development of DSM Option Set

The first task in the DSM Option Screening component of LDSM is to identify and specify potential DSM options for each EMM region and for future time periods. The set of options applicable in any particular year are determined jointly by characteristics of standard and efficient electric technologies shared with the demand models, the LDSM and the set of DSM options specified. This set can be adjusted and modified to reflect alternative DSM scenarios.

A DSM option is the most disaggregated unit of a DSM program. An option maps a baseline level

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[4]The algorithms within the LDSM representing utility-sponsored DSM programs have not been updated in recent versions of the model, and they would require significant work before they could be used. Utility expenditures on these programs have been declining in recent years, and it is felt that their impact is adequately captured in the efficiency trends seen in the NEMS demand models.

technology or service characteristic to a more efficient DSM technology or service level. At a minimum, the following set of information is used to define a DSM option:

- Customer sector
- Baseline technology
- Efficient technology
- First year option is available
- Ramp-up Period
- Administration costs
- Market: new, existing

The LDSM options database uses the same technologies used in the demand models. For example, a central air conditioner rebate program that promotes high efficiency air conditioners uses the existing stock as the base technology and a higher efficiency unit as the DSM technology.

The first year that the technology is available defines the window of opportunity over which DSM programs can offer options relating to that technology.

Incremental Impacts

The first task in the DSM Option Screening component is the development of the incremental cost and load impacts for each DSM option. These incremental impacts are derived from the base and DSM technologies defined in the end-use technology database. These impacts are used to calculate customer payback, derive rebate levels, and technology penetration levels.

Incremental energy impacts associated with a DSM option is determined on a per unit basis. These energy impacts are referred to as usage indices (UIs). For example, residential impact are measured as a change in unit energy consumption (UEC), measured in kWh/yr., in moving from base technology 1 to efficient technology 2. Commercial impacts are measured in terms of electric usage indices (EUI), in kWh/unit of service demand/yr. This incremental energy impact is calculated as follows:

$$EI_{dir} = UI_{1dr} - UI_{2dr}$$

Where:

EI_{dir}	=	incremental energy change for option d in region r
UI_{1dr}	=	usage index for base technology 1 in region r associated with option d
UI_{2dr}	=	usage index for efficient technology 2 in region r associated with option d

Incremental cost (IC) options are derived by comparing the equipment and maintenance costs associated with the base and DSM technology in the database. If the DSM option is focused on replacing existing equipment, the full costs of the DSM technology are used as the incremental costs. If the DSM option is focused on influencing normal replacement decisions, then the incremental cost is the difference in costs between the base and DSM technologies. Incremental costs have two components, one based on capital costs and the other on maintenance costs per unit (e.g., per refrigerator, or per square foot). Maintenance costs include any ongoing labor or expenditures required to keep equipment operating. The cost of electricity consumed to operate the equipment is not included. Mathematically:

$$ICC_{dr} = TCC_{1r} - TCC_{2r}$$

Where:

ICC_{dr}	=	incremental customer capital costs for DSM option d in region r
ICO_{dr}	=	incremental customer maintenance costs for DSM option d in region r
TCC_{jr}	=	technology capital cost for technology j in each region r
TCO_{jr}	=	technology maintenance cost for technology j in each region r

The incremental demand and energy impacts for options is captured through the use of "delta" load shapes. Delta load shapes represent the difference in electricity consumption by time of day, between use of the base technology and the DSM technology. In this version of the LDSM, load shapes for base and DSM technologies are based on default end-use load shapes and represent unit shapes that can be scaled according to total impact. Though several alternative load shape sources exist, the EPRI RELOAD library, of load shapes forms the basis of the LDSM load shapes. The height and peak impact of each load shape will be derived by scaling the default load shape to the total electricity consumption associated with yearly market penetration. Figure II.4 graphically displays the development of delta load shapes for each DSM option.

Figure II.4. Development of Delta Load Shapes
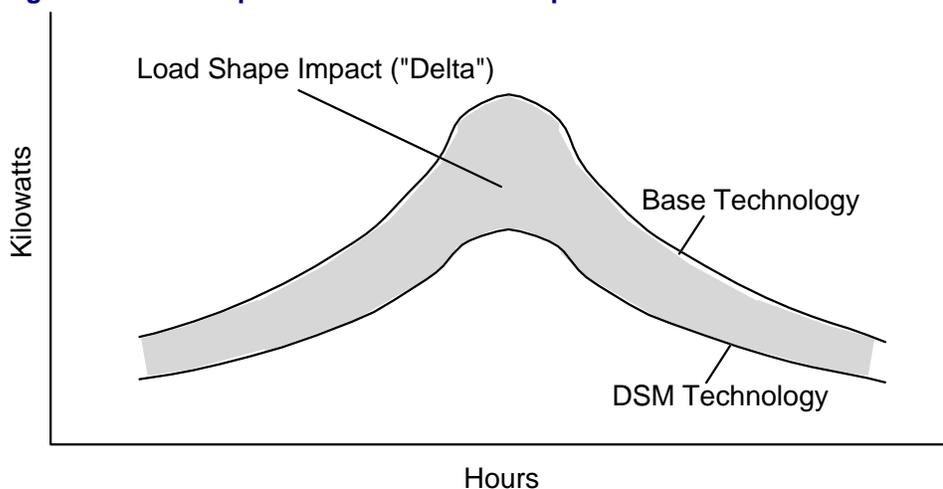
Delta LDCs are developed for each DSM option, in a fashion similar to system load duration curves. Thus a delta load duration curve, denoted by LDC_{dlry}, is defined in megawatt equivalents for DSM option d, load segment l, region r, and year y. For example, the value of LDC_{dlry} for efficient central air conditioners for summer daytime may be 100 megawatts for region r in year y.

Payback Estimation

The first step in determining customer acceptance of DSM options and technologies is to calculate simple payback associated with DSM options without any financial incentives from utilities. Simple payback is derived using the following formula:

$$PB_{ydr} = \frac{ICC_{dr}}{(SV_{yrd} \times ER_{yr}) - ICO_{dr}}$$

Where:

PB_{ydr}	=	payback period in years for DSM option d starting in year y in region r.
SV_{yrd}	=	megawatt-hours of savings for option d in region r for program starting in year y
ER_{yr}	=	electricity rates per-megawatt-hour equivalent in region r for year y
ICC_{dr}	=	is incremental customer capital costs for DSM option d in region r
ICO_{dr}	=	is incremental customer maintenance costs for DSM option d in region r

Electricity rates for year y are input from the EFP submodule.

Penetration Estimation and Rebate Derivation

Development of projections of market penetration and customer participation in utility energy efficiency DSM programs requires detailed information on market characteristics, customer response to DSM programs, and forecasts of future penetration of efficient DSM technologies. In addition, market penetration is related to the level of incentives (e.g., financial rebates) offered by utilities. The LDSM simulates the penetration estimation function for each forecasted future year. This portion of the screening task will (a) develop estimates of maximum market penetration achievable for DSM technologies and the annual participation levels expected, and (b) derive rebate levels.

To estimate the maximum penetration of the market by the DSM option, a payback acceptance curve approach is used. This approach has been used by A.D. Little (1990), and has been incorporated into DSM Screening models such as Synergic Resources Corp.'s COMPASS and EPA's EGUMS model. As is shown in Figure II.5, this approach derives projections of cumulative market penetration from the calculated payback of a DSM option, and differs by customer sector. For example, review of this figure indicates that a commercial DSM option with a 4 year payback would achieve approximately 10 percent of the commercial market. Through variations in financial incentives and rebates, market penetration can be varied.

Figure II.5. Payback Acceptance Approach

During operation, LDSM will follow a four step process. First, LDSM will calculate the rebate level for each DSM option that is necessary to achieve a two (2) year payback. If a DSM option already has less than a two year payback, a rebate is not calculated for the option. The choice of a two year payback level was based on general utility practice. This rebate derivation will be achieved with the following equation:

$$\frac{ICC_{dr} - RB_{dr}}{(LD_{yrd} \times ER_{yr}) - ICO_{dr}} = 2$$

for $0 \le RB_{dr} \le ICC_{dr}$

Where:

ICC_{dr} = incremental customer capital costs for DSM option d in region r
ICO_{dr} = incremental customer maintenance costs for DSM option d in region r
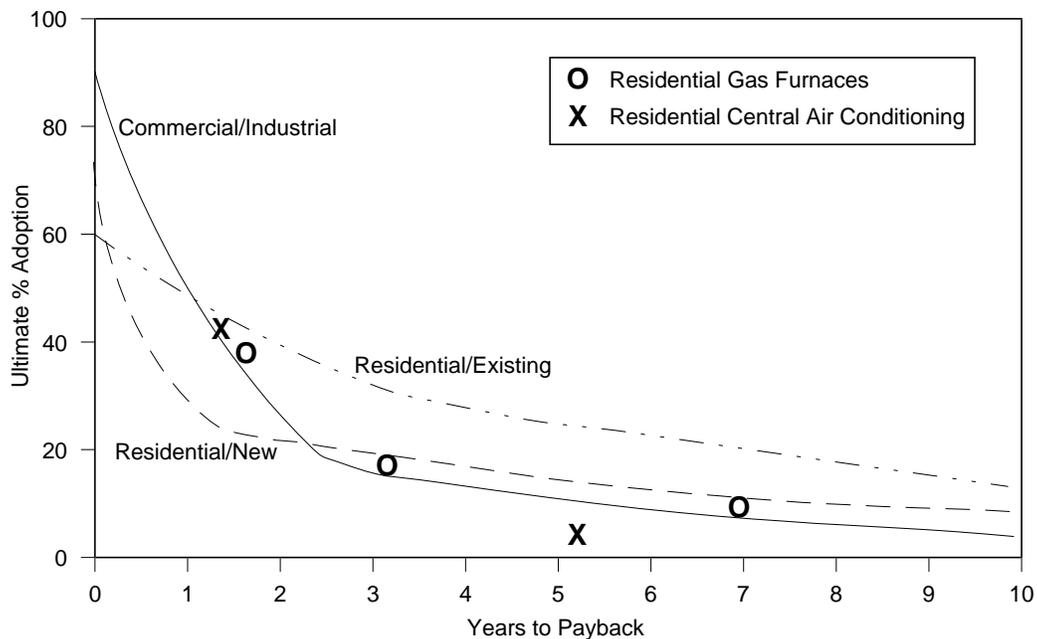RB_{dr} = Rebate level necessary to achieve a 2 year payback in region r for option d
SV_{yrd} = megawatt-hours of savings for option d in region r for program starting in year y
ER_{yr} = electricity rates per-megawatt-hour equivalent in region r for year y

Second, the maximum market penetration of the DSM technology ("TO" technology), MP_{ydr}, associated with option d in region r that begins in every year y is simply read from the payback acceptance curve.

Third, yearly cumulative participation for each option is calculated as a linear function from current market penetration to maximum market penetration, expressed as a percentage of the available market. Current market penetration of efficient technologies will be derived from the stock data supplied by the demand modules by technology region and year. The participation arithmetic will be conducted with the following set of equations. Total potential market size TM_{dry} for a DSM option d[5] in region r for program starting in year y is calculated by:

$$TM_{ydr} = (CM_{y1dr} + CM_{y2dr}) \times MP_{ydr} - CM_{y2dr}$$

Where:

TM_{ydr} = total potential market size for DSM option d[6] in region r year y
MP_{ydr} = maximum market penetration of the DSM technology ("TO" technology), associated with option d region r year y
CM_{y2dr} = current market size for region r for efficient technology 2 associated with option d in year y
CM_{y1dr} = current market size for region r for base technology 1 associated with option d in year y

Annual maximum participation level AP_{ydr} in region r for option d for year y will be calculated with the following equations:
during the ramp-up period:

$$AP_{ydr} = TM_{ydr} \times \frac{(y - y_0 + 1)}{RU_d}$$

beyond the ramp-up period:

$$AP_{ydr} = TM_{ydr}$$

Where:

AP_{ydr} = annual maximum participation level in region r for option d for year y
TM_{ydr} = total potential market size for DSM option d[7] region r year y
RU_d = ramp-up period for option d
y_0 = the first year of implementation of the DSM option d
y = current year for DSM implementation

In the fourth step, the total maximum possible incremental savings TS_{ydr} associated with option d in region r for year y would then be calculated by

$$TS_{ydr} = (UI_{y2dr} - UI_{y1dr}) \times AP_{ydr}$$

Where:

TS_{ydr} = total maximum possible incremental savings associated with option d in region r for year y
AP_{ydr} = annual maximum participation level in region r for option d for year y

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[5]The definition of d will determine what category of technologies are applicable.

[6]The definition of d will determine what category of technologies are applicable.

[7]The definition of d will determine what category of technologies are applicable.

UI_{y1dr} = usage index for base technology 1 in region r associated with option d in year y

UI_{y2dr} = usage index for efficient technology 2 in region r associated with option d in year y

The Free-Ridership Issue and Penetration

In the calculations of program effectiveness, it is important that we include in our consideration the "free riders" issue. Free riders are those customers who would have adopted the program recommended efficiency measures, even in the absence of the DSM program, but who now participate in the program, and, hence, are entitled to the financial incentives of the program. Due to this; energy savings or the load reductions achieved by these customers as a result of DSM programs, do not contribute to net savings, although costs of providing the service to them is a part of program costs.

A study by Marjorie McRae et al, on free riders in the residential sector, conducted a detailed analysis of ten utility DSM programs. The results showed that the net impacts of these residential programs, ranged between 25 to 33% of the utilities' expected values (i.e., 67 to 75% of the participants were free riders). Though the applicability of these numbers to all DSM programs may be questionable, they do indicate that utilities tend to overestimate the impact of their DSM programs. The reason for this is that most utilities do not perform a detailed analysis to estimate the number of free riders in their programs; they do not assume that efficiency improvements may be occurring naturally, and hence by offering DSM programs the utility may be paying for efficiency improvements which may have happened even otherwise.

The current version of the model deals with this problem assuming that the rebates will be paid to a predefined fraction (currently set to 50%) of the customers that apply the efficient (TO) technology. This reflects what is observed in practice, that only a fraction of *potential* free riders will ever apply for rebates. The design and marketing of DSM programs plays a very important role in how many potential free riders may claim rebates. The approach followed in this version of the model lays down the maximum limit of free ridership in any program. This approach is possible, since the restart file gives us information on appliance stocks in the absence of DSM. Thus, the LDSM module uses this information to compute the number of free riders. In the computation of costs of DSM programs by the ECP module, the number of free riders plays an important role. As the number of free riders increase, the program costs go up dramatically, and the program becomes uncompetitive. In this fashion, the present version of the LDSM is able to factor in the role played by naturally occurring efficiency improvements (i.e., the appliance mix in the absence of DSM).

The Targetable Market and Cost Calculations

The demand modules of NEMS provide the LDSM submodule with forecasts of the expected stock changes over the coming years. The categories into which the stock information is divisible are:
(1) Retiring Stock: This includes stock that is expected to naturally retire over the next year. This segment would be a part of the market for "replacement" type DSM programs. The costs incurred in such programs are therefore the incremental cost of the more efficient appliance over the baseline appliance that would have been purchased in the absence of the program.
(2) New Construction or New Stock: This includes those appliances that are meant for the new customers that are likely to join the grid over the next year as a result of new construction. DSM programs targeted at this segment incur costs that are the incremental costs of the more efficient appliance over the cost of the appliance that was to be bought in the absence of the program.

Information Flows Between the LDSM and Demand Modules

Communication between the LDSM and the Demand Modules follows two paths:
(1) Through the RESTART files created by the Residential and Commercial Modules during the pre-LDSM NEMS runs

(2) Through the COMMON blocks defined in the designated INCLUDE files in the LDSM code

Based on the tasks outlined in the main flow chart of the model Table II.3 showing data transfers between the Demand Modules and LDSM submodule has been constructed. The exchange of information between the Demand Modules has the following four objectives:

Table II.3. Information Flow Between LDSM and Demand Modules

Specification of Data Item	Restart File or Include File Name	Direction of Transfer	
		Demand Forecasting Models	LDSM
Market shares of end-use technologies in the entire time horizon if no DSM practices are available	RESIDENTIAL RESTART FILE, COMMERCIAL RESTART FILE	FROM	TO
End-use technology data	DSMRETDB, DSMCMTDB	FROM	TO
End-use demand, for each of the EMM regions, for the current year	DSMTFRES, DSMTFCOM	FROM	TO
Technological shifts due to DSM application, for each of the EMM regions, for the current year, expressed in terms of number of appliances for Residential and amount of service demand for Commercial sector (for the first run year — 0)	DSMTFRES, DSMTFCOM	FROM	TO
Level of DSM Utilization determined as optimal by the ECP module, expressed as percentages of the maximum possible technological shifts resulting from each of the DSM Options listed in the DSM option data base, for the next run year, for each of the EMM regions	DSMTFRES, DSMTFCOM	TO	FROM

- The LDSM reads the technology stock information from the RESTART files to forecast LDSM Program impacts and costs for the entire ECP time horizon (this data is always updated according to the foresight assumptions, in the current run, for each of the sectors of electricity demand)
- The LDSM imports the end-use technology data to calculate incremental DSM option costs and the annual energy savings resulting from technological shifts
- The LDSM supplies the Demand Modules with information about the optimal level of DSM penetration, as determined by the ECP model, so that the Demand Modules, in the next run year, can incorporate these changes into their new appliance stock assessment. Thus the demand modules adjust their forecast to incorporate the impacts of DSM.
- The LDSM imports the actual number of appliances (amount of service demand) that are being shifted from the demand modules, to allow for precise calculation of DSM costs. These costs are then passed on to the EFP module.

Cost-Effectiveness Calculations

The primary screening function of the LDSM DSM screening component is to select DSM options based on overall cost-effectiveness. Benefits and costs for each potential DSM option will be calculated.

Options for which the benefits are higher than costs pass the screen. The benefits and costs are based on the California Total Resource Cost (TRC) test or the Rate Impact Measure (RIM) test. The general form of the tests is given below. The test must be performed for each of the 13 EMM regions being modeled.

$$TRC = \frac{PV \ of \ Avoided \ System \ Costs}{PV \ of \ DSM \ Options \ Costs}$$

This can be further expanded in the following form:

$$TRC_{rd} = \sum_{y=1}^{N} \frac{\dfrac{(MA_{ryl}) \times (LD_{yrdl})}{(1 + i)^y}}{(ICC_{dr}) + \displaystyle\sum_{y=1}^{N} \dfrac{YPC_{yrd}}{(1 + i)^y}}$$

Where:

TRC$_{rd}$	=	Total Resource Costs for region r and option d
MA$_{ryl}$	=	Marginal electricity costs in region r, year y and conforming to the l segment of the load duration curve
LD$_{yrdl}$	=	Changes in the load segment l in year y, due to the DSM option d, in region r
ICC$_{dr}$	=	incremental customer capital costs for DSM option d in region r
YPC$_{yrd}$	=	Yearly option costs for program d, in year y, in region r
I	=	Discount rate used in the calculations
N	=	Lifetime of appliance in years

The present value (PV) of DSM option costs will be derived by calculating the present value of total incremental customer costs and program costs in each future year associated with program participation. The PV of system avoided costs will be calculated by multiplying regional system avoided costs by load duration curve segment (LD$_{yrdl}$) times the total load shape impact of the DSM option.

DSM Program Aggregation

The final task in the DSM Screening component of the LDSM submodule is the development of aggregate DSM programs. Aggregation of economic DSM options is necessary because of the computational limitations of the ECP submodule. It was decided that the maximum number of DSM programs that are to compete within the ECP optimization scheme should not exceed 12 per region. This keeps the size of the optimization problem and the computational times of the ECP module within the acceptable limits. The aggregation is accomplished by summing together all costs and LDC impacts for each DSM option within each program.

DSM Program Disaggregation

The final component of the LDSM submodule is the disaggregation of the DSM programs chosen by the ECP submodule for utility investment. The ECP submodule may choose full or less than full implementation of DSM programs. Within LDSM, the scale chosen by ECP is used as the basis for determining the participation levels in percentage terms. For example, if the ECP chooses 50 megawatts of a potential 100 megawatts aggregated DSM option, then all of the individual options within the aggregated option will be scaled down by 50%. In addition, the DSM programs chosen by ECP are based on EMM regions. The LDSM submodule translates these DSM program decisions to the census division level that is used by the Demand Modules of NEMS.

DSM Option Aggregation

Tables II.4, II.5, II.6, and II.7 contain the DSM options and programs for the residential and commercial sectors that have been implemented in the current version of the LDSM.

Table II.4. Residential DSM Programs in the Current Version of the LDSM

Program Code	Residential Program Description
ResHtoHP	Replace Resistance Heating & CAC/RAC with Heat Pump
HiEff_HP	Replace less efficient Heat Pump with more efficient Heat Pump
HiEffCAC	Replace less efficient CAC with more efficient CAC
HiEffRAC	Replace less efficient RAC with more efficient RAC
HeffRefr	Replace less efficient Refrigerator/Freezer with more efficient Refrigerator/Freezer
HiWaterH	Replace less efficient Water Heater with more efficient Water Heater

Table II.5. Commercial DSM Programs in the Current Version of the LDSM

Program Code	Commercial Program Description
HiEffiHP	Replace less efficient Heat Pump with more efficient Heat Pump
HiEffiAC	Replace less efficient CAC with more efficient CAC
HeChillr	Replace less efficient Chiller with more efficient Chiller
HeLights	Replace less efficient Lighting with more efficient Lighting
HeRefrig	Replace less efficient Refrigerator/Freezer with more efficient Refrigerator/Freezer
HeOthrEq	Replace less efficient Other Equipment with more efficient Other Equipment

Table II.6. Residential DSM Options in the Current Version of the LDSM

Option Code	Program Code	Residential Option Description
c11sN	ResHtoHP	Replace Resistance Heating & CAC with HP
c11hN	ResHtoHP	Replace Resistance Heating & CAC with HP
r12sN	ResHtoHP	Replace Resistance Heating & RAC with HP
c21sN	ResHtoHP	Replace Resistance Heating & CAC with HP
c22sN	ResHtoHP	Replace Resistance Heating & CAC with HP
c21hN	ResHtoHP	Replace Resistance Heating & CAC with HP
c31sN	ResHtoHP	Replace Resistance Heating & CAC with HP
c32sN	ResHtoHP	Replace Resistance Heating & CAC with HP
c31hN	ResHtoHP	Replace Resistance Heating & CAC with HP
c32hN	ResHtoHP	Replace Resistance Heating & CAC with HP
r31hN	ResHtoHP	Replace Resistance Heating & RAC with HP
H12sN	HiEff_HP	Replace less efficient HP with more efficient HP
H12sE	HiEff_HP	Replace less efficient HP with more efficient HP

Option Code	Program Code	Residential Option Description
H12mN	HiEff_HP	Replace less efficient HP with more efficient HP
H12mE	HiEff_HP	Replace less efficient HP with more efficient HP
H12hN	HiEff_HP	Replace less efficient HP with more efficient HP
H12hE	HiEff_HP	Replace less efficient HP with more efficient HP
H23sN	HiEff_HP	Replace less efficient HP with more efficient HP
H23sE	HiEff_HP	Replace less efficient HP with more efficient HP
H23mN	HiEff_HP	Replace less efficient HP with more efficient HP
H23mE	HiEff_HP	Replace less efficient HP with more efficient HP
H23hN	HiEff_HP	Replace less efficient HP with more efficient HP
H23hE	HiEff_HP	Replace less efficient HP with more efficient HP
C12sN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C12sE	HiEffCAC	Replace less efficient CAC with more efficient CAC
C12mN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C12mE	HiEffCAC	Replace less efficient CAC with more efficient CAC
C12hN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C12hE	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23sN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23sE	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23mN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23mE	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23hN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23hE	HiEffCAC	Replace less efficient CAC with more efficient CAC
R12sE	HiEffRAC	Replace less efficient RAC with more efficient RAC
R12mN	HiEffRAC	Replace less efficient RAC with more efficient RAC
R12mE	HiEffRAC	Replace less efficient RAC with more efficient RAC
R12hN	HiEffRAC	Replace less efficient RAC with more efficient RAC
R12hE	HiEffRAC	Replace less efficient RAC with more efficient RAC
R13sN	HiEffRAC	Replace less efficient RAC with more efficient RAC
R23sN	HiEffRAC	Replace less efficient RAC with more efficient RAC
R23sE	HiEffRAC	Replace less efficient RAC with more efficient RAC
R23mN	HiEffRAC	Replace less efficient RAC with more efficient RAC
R23mE	HiEffRAC	Replace less efficient RAC with more efficient RAC

Option Code	Program Code	Residential Option Description
R23hN	HiEffRAC	Replace less efficient RAC with more efficient RAC
R23hE	HiEffRAC	Replace less efficient RAC with more efficient RAC
F12sN	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
F12sE	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
F12mN	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
F12mE	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
F12hN	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
F12hE	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
f12sN	HeffRefr	Replace less efficient Freezer with more efficient Freezer
f12mN	HeffRefr	Replace less efficient Freezer with more efficient Freezer
f12hN	HeffRefr	Replace less efficient Freezer with more efficient Freezer
f23sN	HeffRefr	Replace less efficient Freezer with more efficient Freezer
f23hN	HeffRefr	Replace less efficient Freezer with more efficient Freezer
W13sN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W13sE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W13mN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W13mE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W13hN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W13hE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23sN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23sE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23mN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23mE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23hN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23hE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater

Table II.7. Commercial DSM Options in the Current version of the LDSM

Option Code	Program Code	Commercial Options Description
7CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
7CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
7GRRhE	HeOthrEq	Replace standard electric range with high efficiency range

Option Code	Program Code	Commercial Options Description
7GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
7LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
7LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
7L4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
7L4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
7LHmsE	HeLights	Replace mercury lighting with sodium lighting
7LHmsN	HeLights	Replace mercury lighting with sodium lighting
7LHhsE	HeLights	Replace halogen lighting with sodium lighting
7LHhsN	HeLights	Replace halogen lighting with sodium lighting
7RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost refrigerator
7RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost refrigerator
7RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
7RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
1ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
1ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
1A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
1A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
1A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
1A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
1CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
1CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
1GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
1GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
1LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
1LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
1L4H0E	HeLights	Replace 4 ft. high efficiency flourescent lighting with electronic ballast fluorescent lighting
1L4H0N	HeLights	Replace 4 ft. high efficiency flourescent lighting with electronic ballast fluorescent lighting

Option Code	Program Code	Commercial Options Description
1LHmsE	HeLights	Replace mercury lighting with sodium lighting
1LHmsN	HeLights	Replace mercury lighting with sodium lighting
1LHhsE	HeLights	Replace halogen lighting with sodium lighting
1LHhsN	HeLights	Replace halogen lighting with sodium lighting
1RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
1RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
1RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
1RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
3HPP1E	HiEffiHP	Replace a standard HP with a 1995 HP
3HPP1N	HiEffiHP	Replace a standard HP with a 1995 HP
3HPP2E	HiEffiHP	Replace a 1995 HP with a 2000 HP
3HPP2N	HiEffiHP	Replace a 1995 HP with a 2000 HP
3ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
3ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
3A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
3A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
3A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
3A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
3GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
3GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
3LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
3LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
3LHmsE	HeLights	Replace mercury lighting with sodium lighting
3LHmsN	HeLights	Replace mercury lighting with sodium lighting
3RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
3RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
3RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
3RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator

Option Code	Program Code	Commercial Options Description
4HPP1E	HiEffiHP	Replace a standard HP with a 1995 HP
4HPP1N	HiEffiHP	Replace a standard HP with a 1995 HP
4ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
4ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
4A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
4A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
4A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
4A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
4GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
4GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
4LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
4LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
4L4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
4L4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
4LHmsE	HeLights	Replace mercury lighting with sodium lighting
4LHmsN	HeLights	Replace mercury lighting with sodium lighting
4RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
4RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
4RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
4RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
5ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
5ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
5A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
5A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
5A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
5A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
5CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
5CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller

Option Code	Program Code	Commercial Options Description
5GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
5GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
5LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
5LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
5L4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
5L4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
5LHmsE	HeLights	Replace mercury lighting with sodium lighting
5LHmsN	HeLights	Replace mercury lighting with sodium lighting
5RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
5RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
5RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
5RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
8HPP2E	HiEffiHP	Replace a 1995 HP with a 2000 HP
8HPP2N	HiEffiHP	Replace a 1995 HP with a 2000 HP
8ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
8ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
8A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
8A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
8A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
8A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
8CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
8CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
8GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
8GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
8LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
8LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
8LHmsE	HeLights	Replace mercury lighting with sodium lighting
8LHmsN	HeLights	Replace mercury lighting with sodium lighting

Option Code	Program Code	Commercial Options Description
8RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
8RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
8RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
8RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
9HPP1E	HiEffiHP	Replace a standard HP with a 1995 HP
9HPP1N	HiEffiHP	Replace a standard HP with a 1995 HP
9HPP2E	HiEffiHP	Replace a 1995 HP with a 2000 HP
9HPP2N	HiEffiHP	Replace a 1995 HP with a 2000 HP
9ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
9ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
9A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
9A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
9A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
9A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
9CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
9CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
9GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
9GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
9LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
9LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
9LHmsE	HeLights	Replace mercury lighting with sodium lighting
9LHmsN	HeLights	Replace mercury lighting with sodium lighting
9RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
9RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
9RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
9RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
0ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit

Option Code	Program Code	Commercial Options Description
0ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
0A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
0A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
0A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
0A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
0GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
0GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
0LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
0LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
0LHmsE	HeLights	Replace mercury lighting with sodium lighting
0LHmsN	HeLights	Replace mercury lighting with sodium lighting
0LHhsE	HeLights	Replace halogen lighting with sodium lighting
0LHhsN	HeLights	Replace halogen lighting with sodium lighting
0RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
0RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
0RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
0RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
AASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
AASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
AA58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
AA58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
AA81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
AA81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
AGRRhE	HeOthrEq	Replace standard electric range with high efficiency range
AGRRhN	HeOthrEq	Replace standard electric range with high efficiency range
ALIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
ALIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
AL4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light
AL4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light

Option Code	Program Code	Commercial Options Description
ALHmsE	HeLights	Replace mercury lighting with sodium lighting
ALHmsN	HeLights	Replace mercury lighting with sodium lighting
ALHhsE	HeLights	Replace halogen lighting with sodium lighting
ALHhsN	HeLights	Replace halogen lighting with sodium lighting
ARVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
ARVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
ARM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
ARM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
2CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
2CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
2GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
2GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
2LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
2LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
2L4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light
2L4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light
2LHmsE	HeLights	Replace mercury lighting with sodium lighting
2LHmsN	HeLights	Replace mercury lighting with sodium lighting
2LHhsE	HeLights	Replace halogen lighting with sodium lighting
2LHhsN	HeLights	Replace halogen lighting with sodium lighting
2RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
2RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
2RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
2RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
6CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller

Option Code	Program Code	Commercial Options Description
6CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
6GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
6GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
6LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
6LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
6L4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light
6L4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light
6LHmsE	HeLights	Replace mercury lighting with sodium lighting
6LHmsN	HeLights	Replace mercury lighting with sodium lighting
6RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
6RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
6RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
6RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
7ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
7ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
7A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
7A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
7A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
7A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
2ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
2ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
2A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
2A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
2A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
2A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
6ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
6ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
6A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit

Option Code	Program Code	Commercial Options Description
6A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
6A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
6A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit

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III. 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 changes in environmental regulations and increases in demand. 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), limits on carbon emissions, and externality costs. Planning options for achieving the emissions restrictions in the CAAA include installing pollution control equipment on existing power plants and building new power plants with low emission rates.[8] The ECP also considers "banking" emissions allowances (i.e., each year utilities are allocated allowances that entitle them to emit sulfur dioxide (SO_2) and these allowances can be saved for future use). These methods for reducing emission are compared against 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) and is capable of representing regulations for carbon emissions and externality costs for various pollutants.

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.[9] The ECP also contains a market-sharing algorithm and has been modified to evaluate plant retirement decisions.

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[8]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).

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

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 is intended to consider investment decisions for both demand- and supply-side options However, consumer responses are assumed to be represented in the end-use demand modules, so the structure for demand-side management (DSM) options is not utilized within the ECP. It evaluates retirement decisions for fossil and nuclear plants and captures responses to environmental regulations, such as the CAAA or limits on carbon emissions. 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.

Technology choices in the ECP includes 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. New 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 I, Figure I.3). Of the 13 regions, 6 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), and Southwest Power Pool (SPP) Regions. The remaining 3 NERC Regions are divided into a total of 6 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. In the Southeastern Electric Reliability Council (SERC), Florida (FL) is separated from the rest of the Region (STV). The Western Systems Coordinating Council (WSCC) is partitioned into 3 Subregions. The Rocky Mountain Power Area and Arizona-New Mexico Power Area Subcouncils are combined into 1 region (RA). The Northwest Power Pool Area (NWP) and California-Southern Nevada Power Area (CNV) form the other 2 electricity supply regions.

The general level of aggregation for the NEMS is Census Divisions, which are collections of states.[10] However, many utilities operate across state boundaries and the NERC Regions and Subregions provide a better representation of electricity operations. This geographic representation also facilitates collection of data and comparisons with industry projections, both of which are generally conducted at

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[10]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 9 Census Divisions. For additional information, see Energy Information Administration, *NEMS Integration Module Documentation Report*, DOE/EIA-M057(98) (Washington, DC, December 1998).

the utility- or NERC region-level.

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 2020. It is designed to examine environmental policies such as the CAAA, limits on carbon 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).

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 III.1). 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. The end-use demand modules furnish electricity supplies 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 Load and Demand-Side Management (LDSM) Submodule furnishes the load curves for each year in the planning horizon.

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 III.1). Capacity additions for coal- and gas-fired generating capacity are provided to the Coal Market Module (CMM) and the Natural Gas Transmission and Distribution Module (NGTDM), which are used for planning decisions in the respective modules. The RFM also receives capacity additions of renewable technologies. In particular, this is required for technologies with resource constraints or limited sites.

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.

Model Overview and Rationale

Theoretical Approach

The ECP uses a linear programming (LP) formulation to determine planning decisions for the electric power industry. 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 discounted, present value of investment and operating costs. The ECP explicitly incorporates emissions restrictions imposed by the CAAA and provides the flexibility to examine potential regulations such as emissions taxes and carbon stabilization.

The ECP determines decisions for a six-year planning horizon and uses multi-year optimization by solving all the years simultaneously. The ECP "keeps" only those decisions that must be initiated in the current forecast year since the remaining decisions can be reevaluated in a future year. The available options for capacity expansion and environmental compliance encompass a number of intertemporal issues that need to be addressed using a multi-period planning horizon. For example, generating technologies have different licensing and construction periods. Early in the planning horizon, the options are limited to strategies with shorter lead times, such as construction of peaking units. However, the available options increase over a longer period. Additional capacity requirements could be met by initiating construction of a plant with a longer leadtime or waiting a few years and implementing a shorter-term option. The model has the capacity to use a 10 year horizon but presently only uses a six year horizon.
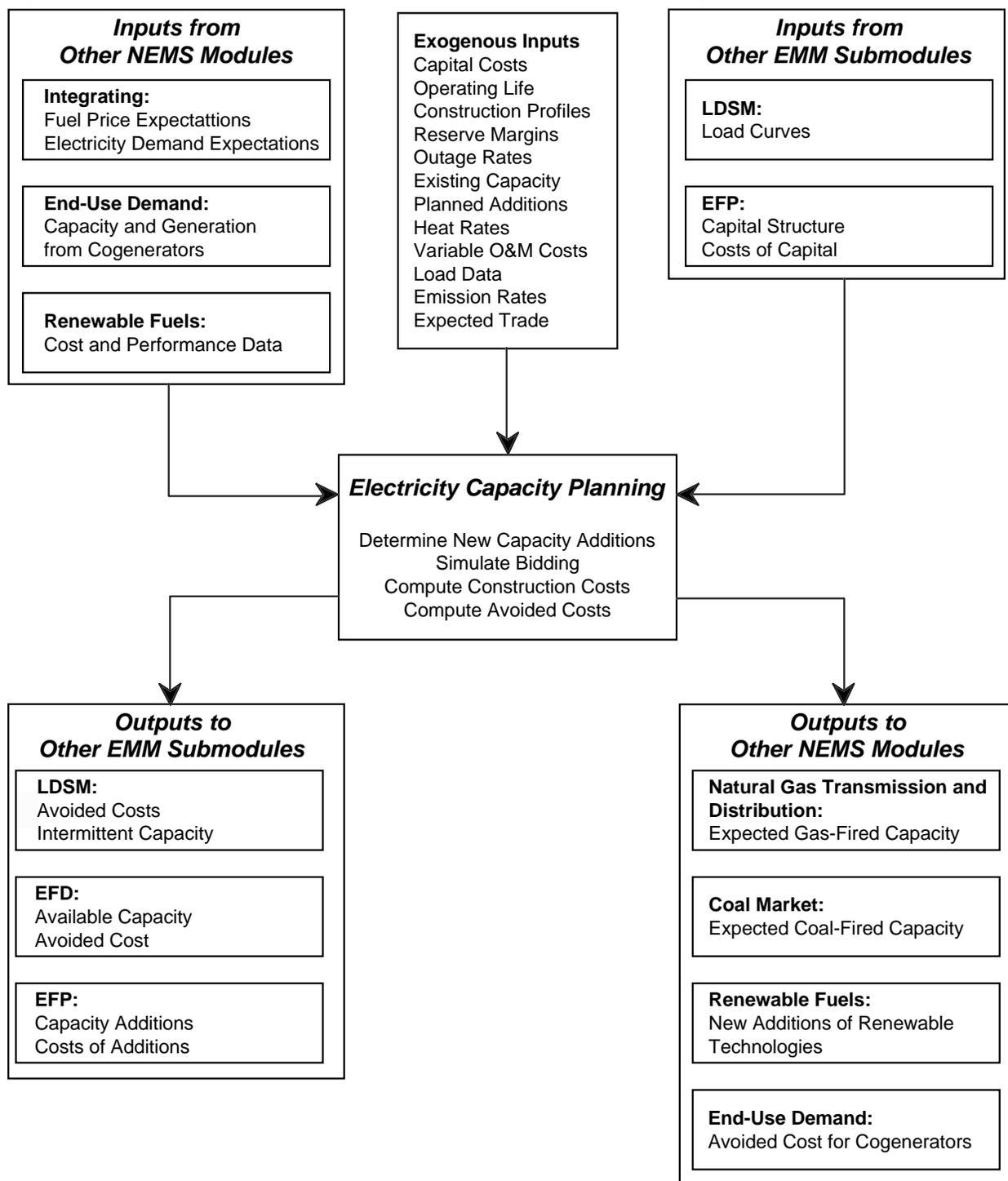
Furthermore, it may be beneficial to implement a particular option prior to the actual need. Utilities in a given region may have a surplus of capacity to serve a particular load category. Nevertheless, it may be cost-effective to build a new unit to replace or lower the utilization of a less economical existing unit. If the public service commission is willing to allow the new asset to be added to the rate base, then this decision depends on whether or not the resulting fuel savings can offset the investment costs that would be incurred earlier than required.

Emissions banking is another intertemporal issue that 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.[11] Based on the 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. For the AEO2001, banking decisions were determined by the CMM to take advantage of its detailed supply curves for coal.

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[11]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.

The ECP uses a modified load duration curve to describe the demands for electric power. A typical load duration curve arranges hourly loads in descending order, but does not identify power requirements chronologically. The ECP categorizes the load requirements into specific seasonal/time of day segments, which are then reordered to provide a monotonically decreasing curve. Maintaining the chronological identity of the demands for electric power allows the ECP to better represent time-dependent variations in both the demand for and supply of electricity.

Figure III.1. Input/Output Flows for the Electricity Capacity Planning Submodule

Inputs from Other NEMS Modules

Integrating:
Fuel Price Expectattions
Electricity Demand Expectations

End-Use Demand:
Capacity and Generation
from Cogenerators

Renewable Fuels:
Cost and Performance Data

Exogenous Inputs
Capital Costs
Operating Life
Construction Profiles
Reserve Margins
Outage Rates
Existing Capacity
Planned Additions
Heat Rates
Variable O&M Costs
Load Data
Emission Rates
Expected Trade

Inputs from Other EMM Submodules

LDSM:
Load Curves

EFP:
Capital Structure
Costs of Capital

Electricity Capacity Planning

Determine New Capacity Additions
Simulate Bidding
Compute Construction Costs
Compute Avoided Costs

Outputs to Other EMM Submodules

LDSM:
Avoided Costs
Intermittent Capacity

EFD:
Available Capacity
Avoided Cost

EFP:
Capacity Additions
Costs of Additions

Outputs to Other NEMS Modules

Natural Gas Transmission and Distribution:
Expected Gas-Fired Capacity

Coal Market:
Expected Coal-Fired Capacity

Renewable Fuels:
New Additions of Renewable
Technologies

End-Use Demand:
Avoided Cost for Cogenerators

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 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).

In the ECP, the LP model is augmented by a market-sharing algorithm that adjusts the solution from the LP model to allow penetration of "competitive" but not "least-cost" alternatives.[12] 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.

Many of the design features of the ECP are intended to represent issues that could not be adequately addressed in the Intermediate Future Forecasting System (IFFS), which was the predecessor to the NEMS. In the IFFS, the electricity component used a heuristic procedure to determine the mix (types and quantities) of unplanned capacity additions.[13] It determined the need for new generating capacity by subtracting the expected available capacity (existing capacity plus planned additions less retirements) from the total capacity requirement (peak demand plus the minimum reserve margin).[14] It searched alternative mixes of new capacity additions and selected the one that combined with the existing capacity to provide the lowest total system cost, which was the sum of the levelized fixed and variable costs.[15]

In the capacity expansion algorithm of the IFFS, the planning horizon was defined by the licensing and construction lead times of the available options. The initial year corresponded to the shortest leadtime and the final year was determined by the longest leadtime. The model evaluated capacity expansion plans for each year sequentially rather than solving for the "least-cost" solution for the entire planning horizon. In contrast, the ECP uses multi-year optimization so that the short- and long-term decisions are determined simultaneously.

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

[13]For more information on capacity planning in the IFFS, see Energy Information Administration, *Model Methodology and Data Description of the Electricity Market Module*, Volume 2, Planning Component, DOE/EIA-M039 (Washington, DC, August 1989).

[14]In the capacity expansion component of the IFFS, existing units that satisfied a predetermined set of criteria were assumed to be life-extended rather than retired. For more information on the requirements for life extension, see Energy Information Administration, *Assumptions for the Annual Energy Outlook 1993,* DOE/EIA-0527(93) (Washington, DC, January 1993).

[15]The levelized cost is the annuity (i.e. constant amount of dollars in each year) that provides the same present value as the actual stream of costs over the service life of the plant.

In the IFFS, both utility and nonutility suppliers were represented in the model, they did not compete directly. The algorithm first searched for the least-cost capacity expansion plan for electric utilities. It then determined if nonutility sources could provide generating capacity more economically.[16] Capacity additions of renewable technologies were exogenous inputs. Domestic and international bulk power purchases were also exogenous assumptions. The planning component of the IFFS could not compete supply and demand options. Reductions in the need for generating capacity due to conservation and demand-side management were determined in the demand modules of IFFS and represented as exogenous adjustments to the expected demand for electricity.

Furthermore, contributions from renewable technologies (e.g., hydroelectric, wind, wood, solar, geothermal, biomass, and solid waste) were also specified exogenously in the IFFS. The load duration curves used in the capacity planning component of the IFFS could not adequately represent these supply and demand options. These curves plot demands for electric power (loads) versus time (i.e., the number of hours that a given load exists). The loads were arranged in descending order to obtain a monotonically, decreasing curve. However, these curves did not maintain the chronological identity of the loads, which is critical to representing seasonal and time-of-day variations in contributions from renewable technologies.

Finally, the IFFS did not endogenously represent environmental regulations such as the CAAA. Instead, compliance strategies were determined using the National Coal Model (NCM), which was a linear programming model of the coal and electric utility industries.[17] The NCM was used in conjunction with the IFFS to produce integrated forecasts. Using demands for electricity and fuel prices from an appropriate IFFS run as an initial set of inputs, the NCM was run to determine strategies for complying with the CAAA. Impacts of the CAAA, including the cost and quantity of retrofitting existing units with scrubbers, fuel switching to lower sulfur coal and oil (resulting in higher fuel costs), and the cost and quantity of allowances traded, and distribution of coal (shares by heat and sulfur content) were then used as inputs to the IFFS. The allowance cost was also included in capacity expansion decisions in the IFFS.

Fundamental Assumptions

It is assumed that capacity additions that have been announced by utilities and nonutilities will be completed as reported.[18] 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. Contributions from cogenerators are determined by the end-use demand modules.

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[16]A detailed description of the capacity expansion model for nonutility sources can be found in Energy Information Administration, *Nonutility Generation Supply Model*, DOE/EIA-M043 (Washington, DC, October 1990).

[17]For a detailed description of the NCM, see Energy Information Administration, *National Coal Model: Executive Summary*, DOE/EIA-0325 (Washington, DC, April 1982).

[18]Planned capacity additions for electric utilities are reported on Form EIA-860, "Annual Electric Generator Report." Scheduled additions for nonutilities are collected on Form EIA-867, "Annual Nonutility Power Producer Report."

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.[19] However, some States are in various stages of deregulating the electric power industry. In these areas, it is assumed that the optimal reserve margin minimizes the cost of unserved energy.

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. Adaptive expectations, which assume that future trends can be extrapolated from historical patterns, are used for future demands and prices.[20] Estimates of future interest rates and inflation rates are not available. Therefore, the ECP uses the myopic expectations, which assume that rates 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. 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 nine different combinations of season (summer, winter, and spring/fall) and time-of-day (daytime, morning/evening, and night) prior to creating the load duration curves (Table III.1). 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. Morning and evening loads are combined for similar reasons. These categories are also designed to accommodate variations in potential contributions from renewable generating technologies.

Table III.1. Definition of Seasonal/Time-of-Day Load Segments

Load Group	Months	Hours
Summer Daytime	June - September	7:00 a.m. - 6:00 p.m.
Summer Morning/Evening	June - September	5:00 a.m. - 7:00 a.m., 6:00 p.m. - 12:00 p.m.
Summer Night	June - September	12:00 p.m. - 5:00 a.m.
Winter Daytime	December - March	7:00 a.m. - 6:00 p.m.
Winter Morning/Evening	December - March	5:00 a.m. - 7:00 a.m., 6:00 p.m. - 12:00 p.m.
Winter Night	December - March	12:00 p.m. - 5:00 a.m.
Fall/Spring Daytime	April - May, October - November	7:00 a.m. - 6:00 p.m.
Fall/Spring Morning/Evening	April - May, October - November	5:00 a.m. - 7:00 a.m., 6:00 p.m. - 12:00 p.m.
Fall/Spring Night	April - May, October - November	12:00 p.m. - 5:00 a.m.

The hourly loads in each of the nine categories, which produce a continuous curve, are approximated by vertical blocks (slices) representing the average load during each period. The two seasonal/time-of-day

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[19]These projections are contained in North American Electric Reliability, Electricity Supply & Demand 1992-2001 (Princeton, NJ, June 1992).

[20]For more information on foresight assumptions, see Energy Information Administration, *NEMS Integrating Module Documentation Report*, DOE/EIA-M057(98) (Washington, DC, December 1998).

groups containing the peak summer and winter loads are separated into peak and off peak segments. For each region, the resulting 11 blocks are then arranged in descending order to produce the load duration curve (Figure III.2).

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.[21] 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. International trade with Canada is also incorporated, but it is assumed that firm power transactions with Mexico do not occur since there are no existing or planned agreements.

Figure III.2. Load Duration Curve with Time-of-Day and Seasonal Load Segmentation

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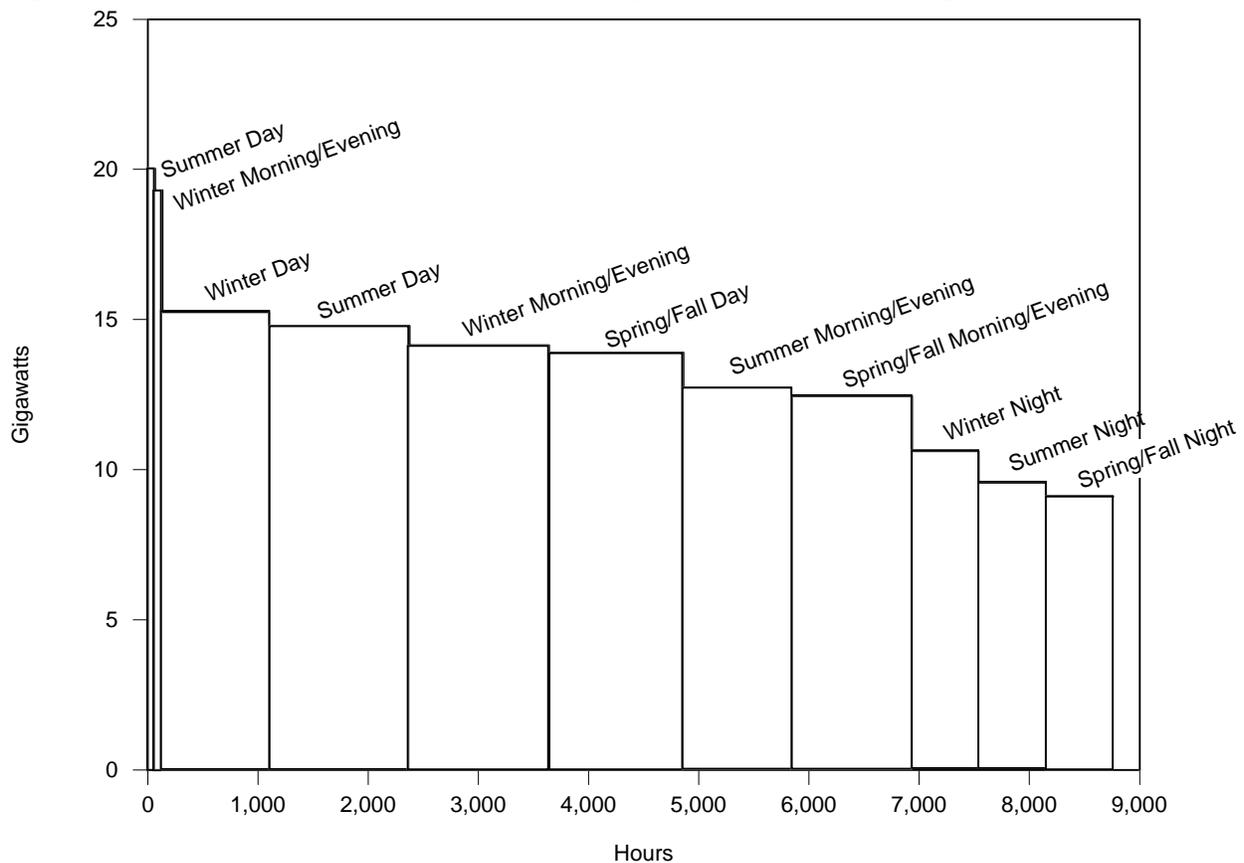
[21]Interregional transmission constraints are derived from Department of Energy, Form OE-411, "Coordinated Bulk Power Supply Program Report."

In the ECP, available supply options include fossil-fired, nuclear, and renewable plants (Table III.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, and solar. Capacity additions for municipal solid waste plants, unlike other renewable technologies do not compete within the ECP, but are exogenously specified by the Renewable Fuels Module.

Potential options for reducing SO_2 emissions in accordance with the CAAA 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. This limit is determined by summing the unit-level emissions allowances allocated in the CAAA.

In addition to the CAAA, 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 III.2). Each unit is assigned to the category that corresponds to the most stringent standard. Consequently, compliance options are limited to those that violate none of the standards. For example, consider an existing coal-fired unit without a scrubber that is allocated allowances in the CAAA based on an emission rate of 1.2 pounds of SO_2 per million Btu. Suppose the state standard imposes the same limit. According to the CAAA, emissions from this unit could exceed this level if additional allowances are purchased. However, this unit is classified in the first category, in which the allowable input fuels are limited to low-sulfur coals with a sulfur content that does not exceed 1.2 pounds of SO_2 per million Btu. This eliminates the option of burning a medium- or high-sulfur coal and purchasing allowances, which would violate the state standard.

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

Category

Existing Unscrubbed Coal, sulfur dioxide standard < 1.20 pounds per million Btu
Existing Unscrubbed Coal, sulfur dioxide standard < 3.34 pounds per million Btu
Existing Unscrubbed Coal, sulfur dioxide standard > 3.34 pounds per million Btu
Existing Scrubbed Coal
Existing Coal Retrofitted with Scrubbers
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
Wind
Solar Thermal
Solar Photovoltaic
Distributed Generation - Base load
Distributed Generation - Peak load

Model Structure

Introduction

The ECP is executed once a year to determine planning decisions that must be initiated in the current forecast year and 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.

The following section provides a mathematical description of the LP model and specifies the objective function and equations of the constraint matrix. The model relies 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.[22] 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.

Reliable electricity supplies for each region are represented by a set of constraints that insure 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

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

categories, whereas a peaking plant type is allocated to the first few segments (see Figure III.2). 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 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

y	=	Year In the Planning Horizon	
z	=	All Years From Year y to the End of the Planning Horizon	$(z=y,y+1,..,6)$
j	=	All Years from Year 1 to Year 4	
w	=	Next Year In Planning Horizon	
p	=	Previous Year In Planning Horizon	
s	=	Season	
r	=	Electricity Supply Region	
e	=	Export Electricity Supply Region	
g	=	Import Electricity Supply Region	
h	=	International Supply Region	
c	=	Dispatchable Capacity Type	
n	=	Renewable Capacity Type	
k	=	Capacity Type Other Than Capacity Type c	
i	=	Intermittent Renewable/Storage Technology	
d	=	Demand-Side Management Technology	
f	=	Fuel Choice	
m	=	Mode of Operation (e.g., "Base," "Intermediate," "Peak")	
l	=	Vertical Load Steps Which Define Total Electricity Load	
u	=	Retrofit Cluster Code	
p	=	Canadian Import Project	
x	=	Retirement Group	
a	=	NOX Retrofit Options	

o	=	NOX Retrofit Plant Groups
v	=	NOX Emissions Containment Area
t	=	Distributed generation Technology Type (Base, Peak)
q	=	Avoided T&D cost supply step for Distributed Generation

Decision Variables

EXC_{yrc}	=	Utilize Existing Dispatchable Capacity Type c (Announced Retirements) in Year y in Region r (Gigawatts)
$EXCR_{yrcx}$	=	Utilize Existing Dispatchable Capacity Type c (Retirement Candidate) in Retirement Group x in Year y in Region r (Gigawatts)
EXR_{yrn}	=	Utilize Existing Renewable Capacity Type n in Year y in Region r (Gigawatts)
EXI_{yri}	=	Utilize Existing Intermittent Capacity Type I in Year y in Region r (Gigawatts)
EXH_{yr}	=	Utilize Existing Hydro Energy in Year y in Region r (Gigawatthours)
OPD_{yrcfms}	=	Allocate Dispatchable Capacity Type c Consuming Fuel f in Mode m in Season s in Year y in Region r (Gigawatts)
OPR_{yrn}	=	Allocate Renewable Capacity Type n in Year y in Region r (Gigawatts)
OPH_{yrl}	=	Allocate Hydro Capacity in Vertical Load Step l in Year y in Region r (Gigawatts)
OCH_{yrh}	=	Allocate Available Canadian Hydro Capacity in Year y from International Region h in Region r (Gigawatts)
BLD_{yrc}	=	Build New Dispatchable Capacity Type c Beginning Operation in Year y in Region r (Gigawatts)
RNW_{yrn}	=	Build New Renewable Capacity Type n Beginning Operation in Year y in Region r (Gigawatts)
INT_{yri}	=	Allocate/Build Intermittent Renewable Type I for Owner Type o Beginning Operation in Year y in Region r (Gigawatts)
DGN_{qrqt}	=	Allocate/Build Distributed Generation Type t and avoided cost supply step q Beginning Operation in Year Y in Region r (Gigawatts)
FGD_{yrcku}	=	Convert Existing Coal Capacity Type c (without scrubber) to Coal Capacity Type k (with scrubber) in Retrofit Cluster Code u With the Retrofit Completed in Year y in Region r (Gigawatts)
BNK_{yiw}	=	Bank Allowances for SO_2 From Year y to the Next Year iw (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)
TRN_{yecr}	=	Dispatchable Capacity Type c Transferred from Export Region e to Import Region r in Year y (Gigawatts)
BDI_{yecr}	=	Build Dispatchable Capacity Type c in Export Region e for Import Region r in Year y (Gigawatts)
BRI_{yenr}	=	Build Renewable Capacity Type n in region e for region r in Year y (Gigawatts)
BII_{yeir}	=	Build Intermittent Capacity Type i in region e for region r in Year y (Gigawatts)
BCH_{yhb}	=	Build Canadian Hydro Capacity from Canadian Import Project b in International Region h in Year y (Gigawatts)
ECH_{yhb}	=	Existing Canadian Hydro Capacity from Canadian Import Project b in International Region h in Year y (Gigawatts)
PMC_{ysr}	=	Planned Maintenance Scheduled Region r in Season s in Year y (Gigawatts)
GEL_{yr}	=	Total Generation for Region r in Year y (Billion Kilowatthours)

NXR_{vga} =   Install NOX Emission Controls Type a on Plant Group g in NOX containment area v.

For dispatchable technologies, the operate decision (OPD_{yrcfms}) 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. Coal-fired units can choose between coals with different sulfur levels. Some coal plants may also have the option of cofiring with biomass (wood and waste products).

Two decision variables are used for existing dispatchable capacity (EXC_{yrc} and EXCR_{yrcx}). The first describes units with announced retirement dates and the corresponding capacity is available until the scheduled retirement date occurs. The second variable represents capacity that can be retired by the ECP. This capacity is available for the entire planning horizon unless the cost of continuing operation exceeds the cost of replacement capacity. Separate variables are also required for the utilization and addition of generating 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.

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

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

EXP_{yr} =   Electricity Capacity Export Limit in Year y and Region r (Gigawatts)

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

CAPL_{yr} =   Capacity Addition Limit In Year y and Region r (Gigawatts)

ALW_y =   Total SO_2 Allowances for Year y (Million Tons)

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

$INTL_{ir}$	=	Intermittent Build Limit for Intermittent Technology I and Region r (Gigawatts)
$RNWL_{nr}$	=	Renewable Build Limit for Renewable Capacity Type n and Region r (Gigawatts)
$CHYL_{hb}$	=	Limit for Accelerating Canadian Hydro Capacity for Project b in International Region h
$FGDL_{cru}$	=	Retrofit Limit for Unscrubbed Capacity c and Retrofit Category u in Region r (Gigawatts)
NOX_{vy}	=	NOX Emission Limit for NOX Containment Area v and for Year y
$DGNL_{yrg}$	=	Amount of new capacity that can be met by distributed generation for supply step q in year y and region r (Giagwatts)

Coefficients

ELA_{yrcfml}	=	Derating Factor (Adjustment for Forced Outage, Planned Maintenance, and Load Following Rates) for Dispatchable Capacity Allocated to Meet Capacity Requirements In Load Step l In Year y, Region r By Capacity Type c With Fuel f In Mode m (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, Region r By Capacity Type n (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)
ELD_{yrt}	=	Derating Factor corresponding to mode of operation (Base, Peak) for Distributed Generation technology type t in Region r in Year y (Fraction)
$ELCH_{yhb}$	=	Derating Factor (Availability of Resource) for Canadian Project b in International Region h In Year y (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)
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)
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)
RMD_{yrt}	=	Contribution Made to Reserve Margin Made by Distributed Generation Type t in Year y for Region r (Fraction)
$SO2_{yrcfms}$	=	Amount of SO_2 Produced Per Unit of Electricity Generated In Year y, Region r By Capacity Type c With Fuel f In Mode m in Season s (Millions of Tons / Gigawatt)
$TLOSS_{yer}$	=	1 - Interregional Transmission Loss Factor from region e to region r in Year y (Fraction)
$COPD_{yrcfms}$	=	Variable Operating Cost Including Expected Fuel Costs to Operate Dispatchable Capacity Type c Using Fuel f In Mode m in Season s for Year y and Region r (Million Dollars / Gigawatt)
$COPR_{yrn}$	=	Variable Operating Cost to Operate Renewable Capacity Type n for Year y and Region r (Million Dollars / Gigawatt)

$COPH_{yrl}$	=	Variable Operating Cost to Operate Hydro Capacity In Load l for Year y and Region r (Million Dollars / Gigawatt)
$CTRN_{yecr}$	=	Cost of Transferring Capacity Type c from Region e to Region r in Year y (Millions of Dollars / Gigawatt)
$CBLD_{yrc}$	=	Investment Cost to Build Capacity Type c With Initial Online Year y in Region r (Millions of Dollars / Gigawatt)
$CRNW_{yrn}$	=	Investment Cost to Build Renewable Capacity Type n With Initial Online Year y in Region r (Millions of Dollars / Gigawatt)
$CBDI_{yecr}$	=	Investment Cost to Build Dispatchable Capacity Type c With Initial Online Year y in Region e for Region r (Millions of Dollars / Gigawatt)
$CBRI_{yenr}$	=	Investment Cost to Build Renewable Capacity Type n With Initial Online Year y in Region e for Region r (Millions of Dollars / Gigawatt)
$CINT_{yri}$	=	Investment and Operating Cost to Build/Operate Intermittent Technology I Starting Operation In Year y and Region r (Millions of Dollars / Gigawatt)
$CDGN_{yrt}$	=	Investment and Operating Cost to Build/Operate Distributed Generating Technology t Starting Operation in Year y in Region r (Millions of Dollars)
$CAVD_{yrq}$	=	Investment Cost for New T&D Equipment Avoided by DG for supply step q in Region r.
$CBII_{yeir}$	=	Investment and Operating Cost to Build/Operate Intermittent Technology I Starting Operation In Year y in Region e for Region r (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)
$CFGD_{yrcku}$	=	Investment Cost to Scrub Capacity Type c to Capacity Type k In Retrofit Cluster u in Year y and Region r (Millions of Dollars / Gigawatt)
$SHOURS_s$	=	Hours in Season s (Thousands of Hours)
$CPMR_{rc}$	=	Amount of Time Required for Planned Maintenance for Capacity Type c in Region r (Thousands of Hours)
$ISHR_i$	=	Amount of Generation for Intermittent Capacity Type i That Is Counted Toward Minimum Generation Requirement (Fraction)
$RSHR_n$	=	Amount of Generation for Renewable Capacity Type n That Is Counted Toward Minimum Generation Requirement (Fraction)
$RMIN_y$	=	Amount of Total Generation or Sales That Must Be Provided by Renewable Technologies (Fraction)
$LHRS_l$	=	Hours in Load Segment L (Thousands of Hours)
$NOXE_{yvrcfms}$	=	Amount of NOX Produced per Unit of Electricity Generated in Year y for NOX Containment Area v from Region r by Capacity Type c with Fuel f in Mode m and in Season s (Billions of Tons / Gigawatt)
$NOXR_{voay}$	=	Reduction in Amount of NOX Produced Due to Investment in NOX Control Technology a for Plant Group o in NOX Containment Area v in Year y
$CNOX_{voa}$	=	Investment Cost to Retrofit Plant Group o with NOX Control Technology a
$CFSHR_{cr}$	=	Biomass Cofiring Share for Capacity Type c in Region r (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. 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) of existing dispatchable capacity types ($CFXC_{yrc}$ • EXC_{yrc} and $CFXCR_{yrcx}$ • $EXCR_{rcx}$)
- operation (variable) of dispatchable capacity types ($COPD_{yrcfms}$ • OPD_{yrcfms})
- operation of renewable capacity types ($COPR_{yrnm}$ • OPR_{yrnm})
- operation of hydro capacity ($COPH_{yrl}$ • OPH_{yrl})
- construction and operation of intermittent renewable technologies ($CINT_{yrio}$ • INT_{yrio})
- installation of sulfur dioxide control devices at existing units ($CFGD_{yrcku}$ • FGD_{yrcku})
- installation of nitrogen oxide control devices at existing units ($CNOX_{vga}$ • NXR_{vga})
- transfer of capacity between regions ($CTRN_{yecr}$ • TRN_{yecr})
- construction of new dispatchable capacity types ($CBLD_{yrco}$ • BLD_{yrco})
- construction of new dispatchable capacity types for another region ($CBDI_{yecro}$ • BDI_{yenro})
- construction of Canadian Hydro capacity ($CBCH_{yhp}$ • BCH_{yhp})
- construction of new intermittent capacity types for another region ($CBII_{yeiro}$ • BII_{yeiro}).
- construction of new renewable capacity types ($CRNW_{yrno}$ • RNW_{yrno}).
- construction of new renewable capacity types for another region ($CBRI_{yenro}$ • BRI_{yenro}).
- construction of new distributed generation capacity, adjusted for avoided transmission and distribution expenditures (\{$CDGN_{yrt}$ - $CAVD_{yrq}$\} . DGN_{yrqt}

The objective function is expressed as follows:

$$
\begin{aligned}
(1) \quad MIN \ & \sum_{y}\sum_{r}\sum_{c} CFXC_{yrc}{\cdot}EXC_{yrc} \ + \ \sum_{r}\sum_{c}\sum_{x} CFXCR_{rcx}{\cdot}EXCR_{rcx} \\
& +\sum_{y}\sum_{r}\sum_{c}\sum_{m}\sum_{s}\sum_{f} COPD_{yrcfms}{\cdot}OPD_{yrcfms} \ + \ \sum_{y}\sum_{r}\sum_{c} COPR_{yrnm}{\cdot}OPR_{yrnm} \\
& +\sum_{y}\sum_{r}\sum_{l} COPH_{yrl}{\cdot}OPH_{yrl} \ + \ \sum_{y}\sum_{r}\sum_{i} CINT_{yri}{\cdot}INT_{yri} \ + \ \sum_{y}\sum_{r}\sum_{d} CDSM_{yrd}{\cdot}DSM_{yrd} \\
& +\sum_{y}\sum_{r}\sum_{c}\sum_{k}\sum_{u} CFGD_{yrcku}{\cdot}FGD_{yrcku} \ + \ \sum_{a}\sum_{o}\sum_{v} NXR_{voa}{\cdot}CNOX_{voa} \ + \ \sum_{y}\sum_{e}\sum_{c}\sum_{r} CTRN_{yecr}{\cdot}TRN_{yecr} \\
& +\sum_{y}\sum_{r}\sum_{c} CBLD_{yrc}{\cdot}BLD_{yrc} \ + \ \sum_{y}\sum_{e}\sum_{r}\sum_{c} CBDI_{yecr}{\cdot}BDI_{yecr} \ + \ \sum_{y}\sum_{h}\sum_{b} CBCH_{yhb}{\cdot}BCH_{yhb} \\
& +\sum_{y}\sum_{e}\sum_{i}\sum_{r} CBII_{yeir}{\cdot}BII_{yeir} \ + \ \sum_{y}\sum_{r}\sum_{n} CRNW_{yrn}{\cdot}RNW_{yrn} \ + \ \sum_{y}\sum_{e}\sum_{n}\sum_{r} CBRI_{yenr}{\cdot}BRI_{yenr} \\
& +\sum_{y}\sum_{r}\sum_{t}\sum_{q} (CDGN_{yrt}-CAVD_{yrq}){\cdot}DGN_{yrqt}
\end{aligned}
$$

Description of Constraints

Emissions. These constraints limit the emissions produced as a result of electricity generation. The equations below are described for SO_2 and NOX emissions, but similar constraints can be included for

other emissions such as carbon by substituting the appropriate emissions coefficient. 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 utility-level. In each year, the emissions limit is determined by the sum of the allowances (ALW_y). However, the allowances do not have be used in the year that they are allocated—they can be banked for future use. In the model, banking will be represented by rolling an allowance forward to the next year where it can again be used or banked. Therefore, emissions in a given year can exceed the sum of the allowances by using allowances banked in a previous year (BNK_{py}) or decreased by banking allowances for a subsequent year (BNK_{yj}). Since the ECP searches for the planning options that minimize the present value of costs for the entire planning horizon, banking will occur if the present value of the cost of reducing emissions in the given year is less than the corresponding value in the subsequent year. For AEO 2001, banking decisions were determined by the Coal Market Module (CMM) and passed to the ECP.

Potentially, each capacity type may produce emissions. The level depends on the fuel used, pollution control devices installed, and amount of electricity produced. The decision variable OPD_{yrcfms} represents the allocation of generating capacity type c and fuel type f to mode of operation m. The coefficient $SO2_{yrcfms}$ describes the corresponding emissions rate associated with the production of electricity. It accounts for the utilization rate for the capacity type, the fuel consumed, and the removal of emissions (if any) due to pollution control equipment. In coal-fired plants, emissions can be reduced by switching to a lower sulfur fuel or by mixing coal with biomass, which is represented by an additional fuel type f that has the combined characteristics of these fuels (e.g., fuel cost, emission rate). The product of the decision variable and its coefficient gives the total emissions. A national level constraint is represented as follows:

$$(2) \qquad \sum_r \sum_c \sum_f \sum_m \sum_s SO2_{yrcfms} \cdot OPD_{yrcfms} + BNK_{yj} - BNK_{py} \leq ALW_y$$

for every year y in the planning horizon.

If some states mandate more stringent standards by prohibiting allowance trading, then additional regional constraints would be needed. For each region, the limit on emissions would be the sum of allowances allocated to units within the region (RGS_{yr}). The regional constraints are structured as follows:

$$(3) \qquad \sum_c \sum_f \sum_m \sum_s SO2_{yrcfms} \cdot OPD_{yrcfms} \leq RGS_{yr}$$

for every year y and for each region r with more stringent SO_2 regulations.

Within a given electricity supply region, some states may impose additional standards whereas others may not. If a particular state prohibits allowance trading, then utilities within that state will not be allowed to exceed their emissions limit by purchasing allowances. Consequently, these utilities must develop compliance plans that reflect the amount of retrofitting and/or fuel switching that is required to meet their allocation of allowances. These compliance plans, which must be reported to the Environmental Protection Agency, can be incorporated in the ECP as lower bounds on retrofitting and fuel switching so that utilities in the appropriate state(s) achieve their emissions targets without purchasing allowances.

Selected states are also subject to limitations on nitrogen oxide (NOX) emissions. These restrictions may require that existing units be retrofitted with control devices. These limits are represented as follows:

$$\sum_r \sum_c \sum_f \sum_m \sum_s OPD_{yrcfms} \cdot NOXE_{yvrcfms} - \sum_v \sum_o \sum_a NXR_{voa} \cdot NOXR_{voay} \leq NOX_{vy}$$

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. These constraints are defined as:

$$(4) \qquad \sum_s SHOURS_s \cdot PMC_{yrcs} - CPMR_{rc} \cdot EXC_{yrc} \sum_x CPMR_{rc} \cdot EXCR_{rcx} - \sum_{j=1}^{y} CPMR_{rc} \cdot BLD_{jrc} \geq 0$$

for every dispatchable capacity type c in year y and region r.

The first term, $SHOURS_s \cdot PMC_{rsy}$, contains the decision variable for planned maintenance and represents the total amount of maintenance allocated to each dispatchable capacity type over all seasons in each region and year. The terms $CPMR_{rc} \cdot EXC_{ryc}$ and $CPMR_{rc} \cdot EXCR_{rcx}$, define the annual maintenance requirements for each existing capacity type c. Similarly, the term $CPMR_{rc} \cdot BLD_{jrc}$ 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.

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.

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. For each segment of the load duration curve, the capacity requirement (ELC_{yrl}) corresponds to its height.

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 (OPD_{yrcfms}) and the corresponding derating factor (ELA_{yrcfml}).

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. There are two dispatch modes. First, the total capacity can be used over as of the peak most load slices as possible until all the renewable energy is used. Second, the capacity can be operated at the average capacity factor uniformly over all the load

segments. In either case the contribution to load is the product of the capacity (OPR_{yrn}) and the corresponding derate / capacity factor (ELR_{yrnl}). 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.

Also, generating capacity with intermittent energy sources (Existing - EXI_{yri}, New - INT_{yrio}, New Import - BII_{yeiro}) 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}).

$$
\begin{aligned}
(5) \quad & \sum_c \sum_f \sum_m ELA_{yrcfml} \cdot OPD_{yrcfms} \; + \; \sum_n ELR_{yrnl} \cdot OPR_{yrn} \; + \; \sum_i \sum_{z=1}^{y} ELI_{zril} \cdot INT_{zri} \\
& + \; ELH_{yrl} \cdot OPH_{yrl} \; + \; \sum_i ELI_{yril} \; + \; \sum_i \sum_e \sum_{j=1}^{y} ELI_{jril} \cdot TLOSS_{zer} \cdot BII_{zeir} \\
& + \; \sum_h OCH_{yrh} \; \geq \; ELC_{yrl}
\end{aligned}
$$

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

Capacity Balance Rows. For each capacity type, region, year, and season, the capacity balance equations limit production of electricity by the available generating capability, which includes existing and new units. Existing capacity includes units that have announced retirement dates (EXC_{yrc}) and units that can be retired if new capacity is more economical ($EXCR_{rcx}$). It also accounts for capacity that is unavailable due to scheduled maintenance. These constraints are specified for all available conventional and advanced plant types.

In the Capacity Balance Rows, negative terms define the available capacity while positive terms represent the disposition of capacity. Each operate vector (OPD_{yrcfms}) will consume/use capacity in order to produce electricity. The available generating capability for capacity type c in each year is the sum of the existing capacity (EXC_{yrc} and $EXCR_{rcx}$) and the cumulative new capacity (BLD_{yrco} or BDI_{yecro}) that has been placed into service, adjusted for planned maintenance (PMC_{yrsc}). The amount of existing capacity is also affected by decisions to retrofit units and decisions to export or import existing capacity. For retrofits ($FGD_{yrck)}$, the capacity balance row for coal capacity without scrubbers has a positive term to indicate a decrease in the available capacity and corresponding equation for coal plants with scrubbers has a negative term to reflect an increase in generating capability. Exports (TRN_{yrcg}) reduce the supply to meet use of native capacity, while imports (TRN_{yecr}) add to the available capacity. Renewable capacity is represented in much the same way except there are no retrofits. Hydroelectric capacity is further restricted to include only existing or committed capacity with no imports / exports or new builds of any type. This recognizes that the decision to build new hydroelectric facilities is more strongly influenced by the availability of sites, environmental issues and other noneconomic factors.

There is also a set of capacity 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).

Dispatchable Capacity Balance Row

(6)
$$\sum_f \sum_m \sum_s OPD_{yrcfms} - \sum_{j=1}^{y} BLD_{jrc} + \sum_{j=1}^{y} FGD_{jrck} - \sum_{j=1}^{y} FGD_{jrkc} + \sum_g TRN_{yrcg} - \sum_e TRN_{yecr} \cdot TLOSS_{yer}$$
$$- \sum_e \sum_{j=1}^{y} BDI_{jecr} \cdot TLOSS_{jer} - PMC_{ysrc} - EXC_{yrc} - \sum_x EXCR_{yrcx} \leq 0.0$$

For every dispatchable capacity type c in year y in region r.

Renewable Capacity Balance Row

(7)
$$OPR_{yrn} - \sum_{j=1}^{y} RNW_{jrn} - \sum_e \sum_{j=1}^{y} BRI_{jenr} \cdot TLOSS_{jer} + \sum_g TRN_{yrng} - \sum_e TRN_{yenr} \cdot TLOSS_{yer} - EXR_{yrn} \leq 0.0$$

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

Hydro Energy Balance Row

(8)
$$\sum_l OPH_{yrl} \cdot ELR_{yrl} - EXH_{yr} \leq 0.0$$

for every year y in region r.

Canadian Hydro Capacity Balance Row

(9)
$$\sum_r OCH_{yrh} - \sum_p ELCH_{yhp} \cdot ECH_{yhp} - \sum_p \sum_{j=1}^{y} ELCH_{jhp} \cdot BCH_{jhp} \leq 0$$

for every international region h in year y.

Reserve Margin Requirement. The reserve margin constraints insure 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. Under competition, it is assumed that the optimal reliability level will be market based. Capacity planning under competition is discussed later.

Planning decisions will have to be implemented if the total capacity requirement (RMQ_{yr}) exceeds the existing capacity ($\sum_c EXC_{yrc} + \sum_c EXCR_{rcx} + \sum_n EXR_{yrn} + \sum_i EXI_{yri}$). Decisions to retrofit existing coal-fired units with scrubbers (FGD_{yrck}) will have no effect on total capacity but it will shift capacity between two types (unscrubbed to scrubbed). Available capacity can be increased by building new capacity—either dispatchable (BLD_{yrc}, BDI_{yecr}), renewable (RNW_{yrn}, BRI_{yenr}) or intermittent (INT_{yri}, BII_{yeir}). 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 (TRN_{yrcg} / TRN_{yecr}) and by Canadian hydroelectric imports (BCH_{yrp}). Distributed generation technologies (DGN_{yrt}) operate during peak load and also contribute to reliability.

For regulated utilities, the reserve margin constraint is formulated as follows:

$$\sum_{c}\sum_{j=1}^{y} BLD_{jrc} + \sum_{i}\sum_{j=1}^{y} INT_{jri} \cdot RMI_{jri} + \sum_{n}\sum_{j=1}^{y} RMR_{jrn} \cdot RNW_{jrn}$$

$$\pm \sum_{c}\sum_{k}\sum_{u}\sum_{j=1}^{y} FGD_{jrcku} + \sum_{c}\sum_{e}\sum_{j=1}^{y} BDI_{jecr} \cdot TLOSS_{jer} + \sum_{n}\sum_{e}\sum_{j=1}^{y} RMR_{jrn} \cdot TLOSS_{jer} \cdot BRI_{jenr}$$

(10)

$$+ \sum_{i}\sum_{e}\sum_{j=1}^{y} BII_{jeir} \cdot TLOSS_{jer} \cdot RMI_{jri} + \sum_{c} EXC_{yrc} + \sum_{c}\sum_{x} EXCR_{yrcx} + \sum_{n} EXR_{yrn} \cdot RMR_{yrn}$$

$$+ \sum_{p}\sum_{j=1}^{y} BCH_{yhp} + \sum_{g}\sum_{c} TRN_{yrcg} - \sum_{e}\sum_{c} TRN_{yecr} + \sum_{t}\sum_{j=1}^{y} DGN_{yrt} \geq RMQ_{yr}$$

for every year y and region r.

Electricity Export Constraint. The export constraint limits the interregional flow of electricity out of a region in accordance with existing transmission capability.

(11)
$$\sum_{c}\sum_{g} TRN_{yrcg} \leq EXP_{yr}$$

for every year y and region r.

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

(12)
$$\sum_{y} BCH_{yhp} \leq CHYL_{hp}$$

for every project p in international region h.

Dispatchable Capacity Build Limit. The dispatchable capacity build limit simulates disincentives for overbuilding such as the disallowance by public utility commissions of capital additions to the rate base for new plants that are excess capacity. This constraint also incorporates contributions to the reserve margin requirement of Canadian hydroelectric projects and plants built in one region to serve another.

(13)
$$\sum_{c}\sum_{j=1}^{y} BLD_{jrc} + \sum_{c}\sum_{e}\sum_{j=1}^{y} BDI_{jecr} \cdot TLOSS_{jer} + \sum_{p} BCH_{yhp} + \sum_{n}\sum_{j=1}^{y} RNW_{jrn}$$

$$+ \sum_{n}\sum_{e}\sum_{j=1}^{y} BRI_{jenr} \cdot TLOSS_{jer} \leq MAX \left(RMQ_{yr} - \sum_{c} EXC_{yrc} - \sum_{n} EXR_{yrn}, \ 0.0 \right)$$

for every year y and 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.

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

(14)
$$\sum_{j=1}^{y} INT_{jri} + \sum_{e}\sum_{j=1}^{y} BII_{jeir} \leq INTL_{ir}$$

for every intermittent technology I and region r.

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

$$(15) \qquad \sum_{j=1}^{y} RNW_{jrn} + \sum_{e} \sum_{j=1}^{y} BRI_{jenr} \leq RNWL_{nr}$$

for every renewable capacity type n and 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 specified level of avoided T & D costs.

$$(15a) \qquad \sum_{t} DGN_{yrtq} \leq DGNL_{yrq}$$

FGD Retrofit Limit. The FGD retrofit limit reflects the total amount of unscrubbed capacity type c available for retrofit at the cost given for retrofit cluster u.

$$(16) \qquad \sum_{k} \sum_{j=1}^{y} FGD_{jrcku} \leq FGDL_{cru}$$

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.

$$(17) \qquad \sum_{i} \sum_{l} ELI_{yril} \cdot EXI_{yri} + \sum_{i} \sum_{j=1}^{y} \sum_{l} ELI_{yril} \cdot INT_{jrio} + \sum_{i} \sum_{e} \sum_{j=1}^{y} \sum_{l} ELI_{yril} \cdot BII_{jeir} - PINT \cdot GEL_{yr} \leq 0$$

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. Since renewable generation credits can be traded, the lower bound is actually national rather than regional or utility-level. Thus, the following rows are required for each year of the planning region, but not each region.

$$
\sum_r \sum_i \sum_l ISHR_i \cdot ELI_{yril} \cdot LHRS_l \cdot (EXI_{yri} + \sum_{j=1}^{y} INT_{jri})
$$

$$
(18) \qquad + \sum_r \sum_n \sum_l RSHR_n \cdot ELR_{yrn} \cdot LHRS_l \cdot (EXR_{yrn} + \sum_{j=1}^{y} RNW_{jrn}) / 1{,}000
$$

$$
+ \sum_r \sum_c \sum_f \sum_m \sum_s CFSHR_{rc} \cdot OPD_{yrcfms} \cdot \sum_l ELA_{yrcfml} \cdot LHRS_l - \sum_r RBND_y \cdot GEL_{yr} \geq 0
$$

The first term of the equation accounts for generation from existing and new intermittent technologies. For each load segment l, the product of the utilization rate (ELI_{yril}) and the hours ($LHRS_l$) yields the generation per unit of capacity. Summing over all load segments and then multiplying by the available capacity ($E_{yri} + \sum INT_{zri}$) 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 (wood and waste products) with coal. The product of the cofiring share ($CFSHR_{rc}$) and the coal-fired capacity allocated to produce electricity (OPD_{yrcfms}) indicates the fraction of capacity using biomass. This is then multiplied by the generation per unit of capacity ($ELA_{yrcfml} \bullet LHRS_l$) to provide the total renewable generation from biomass cofiring. The fourth term represents the total 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 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 present value of the marginal cost of compliance in that year.

The renewable credit price is assumed to be the levelized cost of compliance over the operating period for renewable additions. The levelized cost is the annuity (i.e., constant amount of dollars in each year) that provides the same total present value as the actual stream of costs over the time horizon and is determined for the period beginning in planning year (MAXLT + 1), which is the initial operating date for new renewable capacity. That is,

$$
(19) \qquad EPRPSCR_y \cdot \sum_{z=MAXLT+1}^{ECP\$XPH} [(1 + UPGNPD_z)/(1 + AVGDCR)^z] = \sum_{z=MAXLT+1}^{ECP\$XPH} EPRENEW_z
$$

where: ECP$XPH   =   Number of Years in Planning Horizon (Years)

MAXLT =   Lead Time When All Renewable Capacity Types Can Compete to Meet RPS (Years)

EPRPSCR$_y$ =   Levelized Cost for Period Beginning in Year z=MAXLT + 1 (Real

Dollars)

$UPGNPD_z$ = Cumulative Inflation Factor for Year z (Scalar)

AVGDCR = Average Discount Rate (Fraction)[23]

$EPRENEW_z$ = Discounted, Annual Compliance Cost (dual value) in Year z (Mills per Kilowatthour in Nominal Dollars).

Rearranging Equation (19) to solve for the levelized compliance cost yields Equation (20).

$$(20) \qquad EPRPSCR_y = [\sum_{z=MAXLT+1}^{ECP\$XPH} EPRENEW_z] / [\sum_{z=MAXLT+1}^{ECP\$XPH} (1 + UPGNPD_z)/(1 + AVGDCR)^z]$$

Capacity Planning Under Competition

Under deregulation it is assumed that reserve margins will be determined by competitive markets rather than set at a prespecified level. The economically optimal level occurs when the marginal cost of capacity equals the consumer's willingness to pay for capacity, which is represented by the value of unserved energy.

Optimal reserve margins are calculated from the relationship:

$$(21) \qquad (\partial UE /\partial G) \cdot V(UE) = A_t ,$$

where:

A_t = annual carrying cost (dollars per kilowatt per year) of the least expensive generating capacity (combustion turbine), and

$(\partial UE/\partial G) \cdot V(UE)$ = Marginal cost of unserved energy (dollars per kilowatt per year).

This is expressed by a constraint row

$$(22) \qquad \begin{aligned} &\sum_{dsp}\sum_j delemuedsp(dsp,j) * X_{dsp} + \sum_{rnw}\sum_j delemuernw(rnw,j) * X_{rnw} \\ &+ \sum_{int} delemueint(int) * X_{int} + \sum_{dgn} delemvedgn(dgn) * X_{dgn} = delemuerhs \end{aligned}$$

where:

delemuedsp = change in unserved energy per unit of dispatchable capacity dsp, season j,

delemuernw = change in unserved energy per unit of renewable capacity rnw, season j,

delemeint = change in unserved energy per unit of intermittent capacity int, and

delemuerhs = minimum change in marginal unserved energy.

These coefficients are described in greater detail in Appendix III.C.

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[23]Since the RPS constraints include all regions, the average discount rate is used to determine the present value of the corresponding dual variables.

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.[24] 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. Technological optimism refers to the tendency to underestimate costs for new technologies. 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.

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. It is assumed that this factor decreases linearly until the actual costs and estimates are the same.

The number of units currently operational is determined by dividing the available capacity by the typical unit size. The slope of the line that describes the decrease in the technological optimism factor is given by

(23)
$$SLOPE_c = (1 - OPTFAC0_c)/(UNITL_c - UNITB_c)$$

where:

$OPTFAC0_c$ = Initial Technological Optimism Factor

$UNITL_c$ = Number of Units of Capacity Type c Completed When Technological Optimism is No Longer Observed

$UNITB_c$ = Number of Units of Capacity Type c Completed When Technological Optimism Factor is First Applied (i.e. 0)

The technological optimism factor $OPTFAC_{yc}$ for capacity type c in year y is then given by

(24)
$$OPTFAC_{yc} = OPTFAC_0 + SLOPE_c \cdot UNITS_{yc} \qquad \text{for } UNITS_{yc} < UNITL_c$$

where:

$UNITS_{yc}$ = Number of Units of Capacity Type c Completed by Year y

For a given technology, 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.

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[24]For greater detail on technological optimism, learning, and risk, see Energy Information Administration, *NEMS Component Design Report, Modeling Technology Penetration* (Washington, DC, March 1993).

Learning Methodology. EMM uses a learning curve approach to model the commercialization of new technologies. One part of the learning process is the classic learning-by-doing effects—i.e., as experience increases, costs will fall. Cumulative capacity is used as a proxy for experience and the learning curve is broken into three segments. In each of the segments, an assumed rate of cost reduction is applied to each doubling of capacity. For simplicity, the rate of cost reduction is called the slope of the learning curve. The slopes of the learning curve in the three segments are denoted as period 1, period 2 and period 3 learning factors. The respective slopes are 0.1, 0.05, and 0.01. That is, in the first, second, and third segments of the learning curve, a doubling of capacity would reduce costs by 10 percent, 5 percent and 1 percent, respectively.

The period doublings indicate the length of the segment on the x-axis. That is, the "period 1 doubling" is 3 doublings of capacity and the slope of the learning curve in that segment is 0.1. Similarly, the "period 2 doubling" is 5 doublings of capacity. In this part of the learning curve, the slope would be 0.05. That is, a doubling of capacity would cause costs to fall by 5 percent. Beyond the 8th doubling of capacity the slope would be 0.01.[25]

The starting point on the x-axis is the current capacity of each technology. The starting point on the y-axis and the slope of the learning curve depends upon the degree of commercialization of a given technology and its associated cost estimate. For mature, totally commercialized plants, the starting point on the y-axis is the base overnight cost plus a contingency allowance that is described below. Additionally, all such technologies are located in the third segment of the learning curve. An example of such a technology is a conventional pulverized coal plant. Currently, there are approximately 300 gigawatts (GW) of conventional scrubbed coal plants. For this technology, the starting point on the x-axis would be 300 GW. The starting point on the y-axis would be $1021 per kilowatt (kW) of capacity. After an additional 300 GW of this technology is built, costs would fall by 1 percent (about $10 per kW).

Another technology may have full-scale operating power plants, but the technology is not fully commercialized. Such a technology would likely be located on the second segment of the learning curve. The overnight costs plus a contingency are used as the starting point on the y-axis. An example of such a technology is wind.[26]   Currently, there is 2.6 GW of wind capacity in the United States, and thus the starting point on the x- and y-axis would be 2.6 GW of capacity and $919 per kW, respectively. For this technology, after an additional 2.6 GW of capacity is constructed, costs would fall by 5 percent (about $50 per kW). Each subsequent doubling of capacity up to 32 (1 to 2, 2 to 4, 4 to 8, 8 to 16, 16 to 32) GW would cause costs to fall by another 5 percent.   After 32 GW of capacity are built, each doubling of capacity would cause costs to fall by 1 percent.

A final type of technology is one where there are no full-scale operating power plants. For such technologies, each doubling of capacity up to 3 doublings causes costs to fall by 10 percent.   From the 4th to the 8th doubling of capacity, costs fall by 5 percent for each doubling, and after that point a doubling of capacity causes costs to fall by 1 percent. Thus, for each such technology, 8 doublings of capacity causes costs to fall by 44 percent (.9*.9*.9*.95*.95*.95*.95*.95).

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[25]For the purpose of computing the learning effects, the maximum increase in capacity is one-half doubling in any given year.
[26]International experience is accounted for in the learning calculation and is discussed below.

International Learning Effects. The effects of the construction and operation of a given technology outside the United States on learning is considered in the methodology. If plants built outside the United States are of the identical design and are constructed and or operated by U.S. firms, the number of units constructed abroad is used to determine the starting point on the x-axis. Conventional light water-reactors are being built in Asia (Japan, Taiwan, and China). Because the units being built in Asia are conventional light water reactors, their designs are different from the passively safe design of the AP600. Although, in some cases, firms from the United States supplied the NSSS, only foreign firms are managing the construction of the plants. It is not clear whether such organizations would be willing or able to compete in the United States. In addition, the nuclear regulatory institutions in countries such as Taiwan are different than that in the United States. The learning includes dealing with organizations such as the U.S. Nuclear Regulatory Commission. In short, because of institutional differences between countries in Asia and the United States, design differences between conventional and passively-safe light water reactors, and the fact that the firms constructing foreign plants have no experience in the United States, international nuclear experience is not included in estimating the learning-by-doing effects.

Capital costs for all new electricity generating technologies decrease in response to foreign as well as domestic experience. International learning effects are limited to the equivalent of one unit of a new technology per year. Wind and solar photovoltaic effects are limited to 50 megawatts and 5 megawatts per year, respectively, despite much greater actual additions observed and expected over the forecast period. The effects of learning are represented by a log linear function, which implies a decrease in costs by a constant percentage for each doubling of capacity. Capacity is defined by the number of units completed, which has already been determined to compute the technological optimism factor.

Mathematically, the cost for any unit N can be expressed as:[27]

(25)
$$C_N = C_1 \cdot N^b$$

where

C_N	=	Cost of Nth generating unit (Dollars per Kilowatt)
C_1	=	Cost of first generating unit (Dollars per Kilowatt)
N	=	number of units currently completed

Rearranging Equation (25), b can be determined by letting N equal 2 (i.e., considering a doubling of capacity between the first and second units). That is,

(26)
$$b = \ln(1 - LCR)/\ln(2)$$

where:

LCR   =   cost reduction for every doubling of capacity (Fraction)

Note that b is negative so that as N increases the corresponding cost decreases. That is,

(27)
$$C_2 = C_1 \cdot 2^b; \quad C_4 = C_1 \cdot 4^b; \quad C_8 = C_1 \cdot 8^b; \quad \ldots$$

The cost reductions continue until the number of units completed reaches a prespecified level *n*, when learning-by-doing effects are assumed to be no longer observed. Cost estimates that assume no

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[27]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).

additional learning are typically referred to as "nth-of-a-kind" costs. Capital cost data used in the ECP represent nth-of-a-kind costs (C_n), so the learning factor associated with the Nth unit (N<n), LF_N, is expressed as a multiplier of C_n. That is, LF_N describes the decrease in capital costs between the Nth-of-a-kind and nth-of-a-kind units.

(28)
$$C_N = C_n{\cdot}LF_N$$

Solving equation (25) for both C_N and C_n and substituting the results into equation (28) yields

(29)
$$LF_N = (N/n)^b$$

Risk. EMM uses engineering estimates for the costs of generating technologies. Because there are operating conventional and evolutionary technologies, information on the realized costs of these technologies is available. Thus, only the traditional project contingency factor that ranges from 5 to 10 percent is used.[28]

However, no information is available for the realized cost of a new, non-commercial technology, because, by definition, operational versions of such technologies do not exist. History has shown that the cost estimates for such technologies tend to be too low (optimistic). To account for this financial risk, an additional contingency allowance that from 10 to 15 percent is applied to the first unit of a technology that is built. (In Table III.3, this is called the "technological optimism factor.") This contingency allowance falls for the second and third units built and would be zero for all additional units. The total contingency for the "first of a kind" such technology is between 20 and 25 (10 to15 plus 10) percent. The higher contingency is included to account for the financial risk associated with the construction and operation of a "different" technology. The total contingency allowance falls to 10 percent for the 4th unit constructed.

These "optimism factors" are based on an analysis by Independent Project Analysis (IPA)[29]. The contingency allowance for the AP600 is based on the IPA analysis of the integrated gas combined-cycle (IGCC) technology. The IGCC technology is similar to the AP600 in that its components are proven but the design is different. The total contingency allowance for the AP600 is the same as that used by Parsons, Inc. for the IGCC[30]. It is higher than the 20 percent contingency used by the Nuclear Regulatory Commission to estimate the cost of decommissioning (de-constructing) nuclear power plants. A cost estimate (about $1770 per kW of capacity net of contingencies) for the AP600 made by the Electric Power Research Institute (EPRI) is used. This estimate is similar to that made by Westinghouse- the firm that would supply the components in the nuclear steam-supply system (NSSS) for the AP600.[31] According to Westinghouse, the estimated cost of building the first AP600 is about $1750 per kW of capacity, net of contingencies[32]. However, in order to account for the financial risk in building the first AP600 (and the first nuclear power plant built in the United States in several decades), a contingency allowance of 25 percent is used.

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[28]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".

[29]Risk Analysis of Three Emerging Power Generating Technologies, prepared for the Energy Information Administration by Independent Project Analysis, Inc., December 1993.

[30]Parsons Inc. is an engineering firm specializing in the construction of coal-fired power plants.

[31]Much of the information about this cost estimate is not in the public domain.

[32]"AP600 First-of-Kind Engineering Advanced Light Water Reactor Design Overnight Capital Cost Estimate (Non-Proprietary)", Document No. GW-G3Z-003 Rev. 0, Westinghouse Electric Corporation prepared for Advanced Reactor Corporation, December 31, 1997, Page ES-4.

Risk Premiums

The discount rate used to determine the present value of costs in the objective function of the ECP is based on the weighted average, after-tax cost of capital.[33] However, the discount rate for each technology is adjusted using risk premiums that depend on the construction lead times.[34]

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[33]As described above, the objective function of the ECP minimizes the total, discounted present value of the costs (i.e., revenue requirements) associated with the construction and operation of powerplants over the planning horizon.

[34]The licensing period, which is assumed to be one year, requires little capital investment and is not included. For a detailed description of the methodology and assumptions used to develop risk premiums, see Appendix III.D.

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 these technologies, 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

$$EPPHRT_{yc} = EPPHRT0_c + (EPPHRTN_c - EPPHRT0_c) \cdot (\frac{y - UPDHRY0_c}{UPDHRYN_c - UPDHRY0_c})$$

(30)
$$\text{for } UPDHRY0_c \leq y \leq UPDHRYN_c$$

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

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

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:[35]

(31)
$$MS_i = MC_i^a / \sum_j MC_j^a$$

where:

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

In Equation (31), market shares are determined on the basis of marginal costs. The exponent a, which is used for all technologies, is negative so that the more competitive a technology becomes (i.e., the smaller the value of MC_i), the larger the share it will gain. In the ECP, "competitiveness" is measured using the *reduced cost* from the LP model, which describes the cost reduction required for a particular option to be selected by the LP model.[36] The ratio of its actual cost to its required cost (i.e., actual cost minus reduced cost) is used for MC_i. This ratio is given by

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[35]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).

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

(32)
$$CSTRATIO_{yrc} = (CBLD_{yrc})^a / (CBLD_{yrc} - RC_{yrc})^a$$

where:

$CSTRATIO_{yrco}$	=	Ratio of Actual Cost to Required Cost for Building Capacity Type c Beginning Operation in Year y in Region r (Scalar)
$CBLD_{yrco}$	=	Investment Cost to Build Capacity Type c With Initial Online Year y in Region r (Millions of Dollars / Gigawatt)
RC_{yrco}	=	Reduced Cost to Build Capacity Type c With Initial Online Year y in Region r (Millions of Dollars / Gigawatt)

A prespecified tolerance level, EPMSTOL, is used to for all technologies to eliminate options that are considered noncompetitive because the cost reduction required for penetration is too large. That is, $CSTRATIO_{yrc}$ is set to 0 if $CSTRATIO_{yrc}$ exceeds 1 + EPMSTOL so that the corresponding market share will be 0. After $CSTRATIO_{yrc}$ has been determined for all basic and nonbasic vectors evaluated by the market-sharing algorithm, the individual market shares for each technology choice are derived using Equation (31). That is,

(33)
$$MS_{yrc} = CSTRATIO_{yrc} / \sum_y \sum_c CSTRATIO_{yrc}$$

These market shares are then used to reallocate the total capacity additions determined by the LP model ($TOTBAS_r$). The "revised" build decisions (BLD'_{yrco}) are given by

(34)
$$BLD'_{yrc} = MS_{yrc} \cdot TOTBAS_r$$

Finally, the capacity expansion decisions that were selected by the LP model (BLD_{yrc}) must be decreased to account for the new capacity that was reallocated. This is accomplished by Equation (35) and Equation (36), which reduce each of the original decisions in proportion to their share of the total market.

(35)
$$TOTNBS_r = \sum_y \sum_c BLD'_{yrc}$$

where:

BLD'_{yrc}	=	Market-Sharing Build Decisions for Capacity Type c Beginning Operation in Year y in Region r (Gigawatts)

(36)
$$BLD'_{yrc} = BLD_{yrc} - TOTNBS_r \cdot (BLD_{yrc} / TBLD_r)$$

where:

BLD_{yrc}	=	LP Build Decisions for Capacity Type c Beginning Operation in Year y in Region r (Gigawatts)

Nuclear Retirements

Similar to the market-sharing algorithm, nuclear retirement decisions are determined by utilizing information from the solution of the LP model. In this case, these decisions are evaluated by comparing the cost of continuing to operate existing nuclear capacity, which is an input, to the cost of replacement power, which is an output of the LP model. Four options for the operating lifetime of nuclear units are considered. A unit can be retired early (i.e., 10 years prior to the expiration of the operating license), retired at the end of the operating license, or operated for an additional 10 or 20 years by renewing the license.

For a given capacity type c in region r, the levelized cost of replacing generation from nuclear capacity (LVCSTPLT$_{rc}$) is given by

$$(37) \quad LVCSTPLT_{rc} = (EPLVCAP_{rc} + EPLVFOM_{rc}) / (UPMCF_r \cdot 8.76) + EPLVFLC_{rc} + EPLVVOM_{rc} + EPLVEXT_{rc}$$

where:

EPLVCAP$_{rc}$ = levelized capital cost of capacity type c in region r (dollars per kilowatt)

EPLVFOM$_{rc}$ = levelized fixed operations and maintenance cost of capacity type c in region r (dollars per kilowatt)

UPMCF$_r$ = average utilization rate for nuclear capacity in region r (scalar)

EPLVFLC$_{rc}$ = levelized fuel cost of capacity type c in region r (dollars per thousand kilowatthours)

EPLVVOM$_{rc}$ = levelized variable operations and maintenance cost of capacity type c in region r (dollars per thousand kilowatthours)

EPLVFLC$_{rc}$ = levelized externality cost of capacity type c in region r (dollars per thousand kilowatthours)

The levelized cost of replacement power for a nuclear unit in region r (LVCSTMIN$_r$) is assumed to be the minimum cost among the capacity types c.

Typically, the operating license for a nuclear unit expires after 40 years. After the 25th year, the EMM evaluates the early retirement decision. A unit is retired 10 years before the expiration of the license if

$$(38) \quad W\_NRET1_u > LVCSTMIN_r / 10$$

where:

W_NRET1$_u$ = levelized cost to operate unit u until the end of the operating license (cents per kilowatthour)

LVCSTMIN$_r$ = levelized cost of replacement power in region r (mills per kilowatthour)

Otherwise, the unit continues to operate until the end of the license and is subsequently considered for license renewal. This decision is evaluated 5 years before the expiration of the license. A unit is retired when the license expires if

$$(39) \quad W\_NRET2_u > LVCSTMIN_r / 10$$

where:

W_NRET2$_u$ = levelized cost to operate unit u for an additional 10 years after the end of the operating license (cents per kilowatthour)

Otherwise, the license is renewed for 10 years.

If a unit has its original operating period extended, it is evaluated for a second license renewal five years prior to the new retirement date. A unit is retired when the initial license renewal expires if

$$(40) \quad W\_NRET3_u > LVCSTMIN_r / 10$$

where:

W_NRET3$_u$ = levelized cost to operate unit u for an additional 10 years after the end of the first license renewal (cents per kilowatthour)

Otherwise, the license is renewed for second 10 years.

Demand Expectations

The EMM can determine demand expectations using an alternative method to the original approach used by the Integrating Module.[37] 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.

(41)
$$GDEM_{sry} = DEM\_WGHT_{sr} * GDEM_{srl} + (1 - DEM\_WGHT_{sr}) * DEM\_GRW_{sr}$$

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)

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[37]For more information on the methodology to determine adaptive expectations, see Energy Information Administration, *NEMS Integrating Module Documentation Report*, DOE/EIA-M057(98) (Washington, DC, December 1998).

Appendix III.A. ECP Data Flows

The EMM is modular and can be executed with or without the ECP. A user-specified switch, USW_ECP, controls the execution of the ECP. The subroutine *ELECP* initializes variables and checks the value of USW_ECP. If the ECP is turned off, then the EMM uses the capacity planning decisions from a previous NEMS run. Otherwise, ELECP 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 using OML subroutines.

ECPOML calls *EP$ALLOW*, which sets up the right-hand side of the emissions constraints for each year of the planning horizon. For SO_2, the right-hand side represents the limit corresponding to the sum of the emissions allowances allocated in accordance with the Clean Air Act Amendments of 1991. Restrictions on SO_2 emissions are implemented as national constraints since allowances can be traded. If emissions allowances have been banked by over complying in previous years (i.e., emitting less sulfur dioxide than the sum of the allowances), then the right-hand side is adjusted accordingly. *EP$ALLOW* calls *GETSO2*, which is a data processing routine that obtains the SO_2 allowances from an EMM input file.

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

EP$BLD simulates disincentives for overbuilding generating capacity such as the disallowance by public utility commissions of capital additions to the rate base for new plants that are excess capacity. Electric utilities must have sufficient generating capacity to satisfy minimum reliability requirements, which is defined as the peak demand plus an assumed amount of reserve capacity in case of unexpected demands or unavailable supply (e.g., unplanned maintenance). *EP$BLD* revises the coefficients for constraints that limit capacity additions in excess of the minimum reliability requirements.[38] 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 *EP$PCL* and *EPFLPRC*. *EP$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. This represents recent situations where the bond ratings for some utilities were lowered due to their reliance on capacity purchases from nonutilities, which are considered to be the equivalent of debt. *EPFLPRC* determines the expected fuel prices. These fuel prices are used to determine the coefficients for the discounted present value of fuel costs over the 30-year period in which project expenditures are evaluated.[39]

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[38]Some capacity types, such as wind and solar, are primarily built to displace generation from less economical existing plants rather than to satisfy reliability requirements. *EP$BLD* does not restrict capacity additions of these "fuel savers."

[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 30.

Next, an additional set of operations are performed to revise coefficients for each electricity supply region and year in the planning horizon. Data on firm interregional power flows are obtained by again calling the data processing routine *GETEIJ*. *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 (see above).

The remaining revisions primarily involve updating coefficients for the decision variables in the ECP. These coefficients describe cost and performance characteristics for activities such as retrofitting existing units with scrubbers, building new capacity, and generating electricity from available capacity. *EP$RETRO* revises coefficients of the objective function and constraint matrix for the variables represent retrofits of existing coal-fired units with scrubbers. The primary function of *EP$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 the revenue requirements for construction expenditures and fixed operations and maintenance costs for building new generating capacity and the associated transmission equipment.[40] *EP$BRNW* updates the corresponding objective function value for new renewable capacity (e.g., geothermal, hydroelectric, biomass), excluding intermittent technologies (e.g., wind and solar). For some renewable technologies, the Energy Policy Act of 1992 (EPACT) established cost credits, which are subtracted from the corresponding capital costs. *EP$BRNW* also imposes limits (upper bounds) on capacity additions for renewable technologies due to resource constraints, if appropriate. EP and BDGN determine 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.

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[40]Revenue requirements are the costs that a ratemaking authority (i.e., public utility commission) allows a regulated utility to recover from ratepayers. Capital costs are included in rates over a period of years, which can vary depending on the type of asset.

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.

EP$DSM is designed to modify the coefficients for decision variables that describe investments in DSM programs.[41] These coefficients represent the costs and reductions in load requirements associated with DSM programs. These programs are similar to intermittent technologies in that the impacts can vary according to the season and time of day (e.g., cycling devices for air conditioners).

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. *EPO$BANK* retrieves and stores the allowances banked in the current year. The banked allowances are provided to the Electricity Fuel Dispatching (EFD) Submodule so that the emissions limit for the current forecast year can be increased by the corresponding amount. *EPO$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. 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$AVOID* obtains the avoided cost of electricity (the cost of producing an additional unit of electricity). This value is determined so that the Load and Demand-Side Management Submodule will be able to pre-screen candidates and eliminate programs that are not competitive with supply options. *EPO$BILD* retrieves capacity expansion decisions and provides them to the EFD so that the EFD to adjust the available capacity for future dispatching decisions. *EPO$BILD* also provides investment costs for new capacity to the Electricity Finance and Pricing Submodule (EFP) to include in the revenue requirements. *EPO$RETRO* summarizes decisions to retrofit existing coal-fired units with FGD equipment, which are used by the EFD to calculate emissions in future dispatching decisions. The corresponding investment costs are also passed to the EFP to include in electricity prices. 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.

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[41]ECP does not currently represent demand-side management programs.

Appendix III.B. Data Sources

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

EIA SURVEY FORMS

Form EIA-860

The Form EIA-860 is a mandatory census of electric utilities in the United States that operate power plants or plan to operate a power plant within 10 years of the reporting year. The survey collects data from the electric utilities on existing power plants, and on 10 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-867

The Form EIA-867 is a mandatory survey of all existing and planned nonutility electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. The form is used to collect data on the installed capacity, energy consumption, generation and electric energy sales to electric utilities and other nonutilities by facility. Additionally, the form is used to collect data on the quality of fuels burned and the types of environmental equipment used by the respondent. Planned generators are defined as a proposal by a company to install electric generating equipment at an existing or planned facility. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a contract for the electric energy, or (3) financial closure on the facility.

Form EIA-767

The Form EIA-767 is a mandatory 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-759

The Form EIA-759 is a mandatory census of all operators of electric utility plants producing electric power for public use. The Form-EIA 759 is used to collect monthly data on net generation, consumption of coal, petroleum, and natural gas; and end-of-the-month stocks of petroleum and coal for each plant by prime mover and fuel type combination.

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.

Office of Integrated Analysis and Forecasting, "Cost and Performance Database for New Generating Technologies"

A database of current costs and performance characteristics for a wide range of conventional and advanced generating technologies and emission control options with the following data sources:

Fossil Fueled Power Plants
- EPRI, Technical Assessment Guide (TAG) Electricity supply — 1989
- Oak Ridge National Laboratories, Energy Economic Database (EEDB), various program phases
- EIA, Electric Plant cost and Power Production expenses, 1990

Nuclear Fueled Power Plants
- EIA, Advanced Reactor Sourcebook

Emission Control Technologies
- Vatabuk, estimating Costs of Air Pollution Controls, Louis Publishers, 1990
- EPRI, 1991: United Engineers and Constructors, "Technical Feasibility and costs of selective Catalytic reduction NOx Control," GS-7276
- EPRI, 1991: United Engineers and constructors, "Economic Evaluation of Flue Gas Desulfurization Systems," GS-7193

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

A 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 OE-411 response. FORM OE-411 is described below.

FORM OE-411

The Form OE-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.

Department of Energy, "Northern Lights: The Economic and Practical Potential of Imported Power from Canada," December 1987, DOE/PE-0079

The Northern Lights publication contains data on costs of importing power from Canada and information on interregional reliability issues related to electric power imports from Canada. The cost information includes data on (1) capital costs to build, (2) variable and fixed operating and maintenance costs, and (3) transmission costs.

Data Sources:

- EIA "Annual Outlook for U.S. Electric Power," 1987, and EIA survey data.
- DRI "Energy Review," Winter 1986-1987
- A survey of Canadian taxes by ICF, Incorporated.
- New England Power Pool, New York Power Pool, and Western Area Power Administration
- Reliability data from NERC Mid-Atlantic Area Council, and Northeast Power Coordinating Council.
- Various electric utilities in both Canada and the United States including; Pacific Gas and Electric, Hydro-Quebec, Manitoba Hydro, and British Columbia Hydro.
- Various publications on Canadian energy supply cited in the Northern Lights bibliography.

Environmental Protection Agency: "The National Allowance Data Base, Version 2.11," March 1993.

The "National Allowance Data Base" contains the data elements on utility combustion sources necessary to support a market based system of acid rain controls. This data base is based on the 1985 National Utility Reference File (NURF) data, augmented by the U.S. Department of Energy's (DOE) Energy Information Administration (EIA) data. The NURF data was extensively reviewed and data inconsistencies were eliminated through contact with State and local air agencies and utilities. The "National Allowance Data Base" is utilized to calculate sulfur dioxide (SO_2) emissions allowances (credits), as delineated by the Clean Air Act.

Data Sources:

- The EPA 1985 National Utility Reference File (NURF), 1989. NURF data was submitted to the 10 EPA regions for review of the following key elements: 1985 SO_2 emissions and emissions rate, 1985 total heat input, and 1985 SO_2 emission limits and associated variables.
- 1985 National Emissions Data System (NEDS) submittals.
- Form EIA-767 (EIA, 1982-1989) and Form FPC-67 (FPC,1980-1981).
- Form EIA-759 (EIA, 1980-1989).
- The Federal Energy Regulatory Commission (FERC) Form FERC-423 (FERC, 1985-1989).
- The EIA Integrated Data Base System (IDBS), which consists of the Form EIA-860 (EIA, 1989a) and Form EIA-861 (EIA,1989b).
- Distributed Utility Associates, "Assessing Market Acceptance and Penetration for Distributed Generation in the United States", Spring 1999, prepared for the Energy Information Administration. This report contains cost and performance characteristics for modeling distributed generation in the Electricity Market Module.

Appendix III.C. Derivation of Coefficients
for Capacity Planning Under Competition

SUBROUTINE: SHAVEL

Description: Computes the Shavel/Sanghvi approximation to the cumulative distribution at a point z given its first four cumulants. This is based on first few terms of the Gram-Charlier expression of a distribution as an infinite series of its cumulants.

Parameters:

z	=	z-value (input)
cum1	=	first cumulant of marginal capacity function
cum2	=	second cumulant of marginal capacity function
cum3	=	third cumulant of marginal capacity function
cum4	=	fourth cumulant of marginal capacity function
cum	=	cumulative distribution (output)

Called by: ELREL, EMUE

Calls: NORM

Equations:

$$g1 = \frac{cum3}{cum2^{1.5}}$$

$$g2 = \frac{cum4}{cum2^2}$$

$$norm0 = pinorm * \exp^{-\frac{z^2}{2}}$$

call norm(z1,norm0,normx1)

$$cum = normx1 - \frac{g1*norm0*(z^2-1)}{6!} + \frac{g2*norm0*(3z-z^3))}{4!} + \frac{g1^2*10*norm0*(10z^3-5z-z^5)}{6!}$$

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.

FUNCTION: DELEUE

Description: Develops the contribution of a unit of capacity of a particular ECP type to the reduction in marginal expected unserved energy.

Called by: DELEUE

Calls: Shavel.

Equations:

Determine loss of load probability (LOLP)
CALL Shavel(cum1,cum2,cum3,cum4,LOLP)

$$G1=(\frac{cum3}{cum2})^{3/2}$$

$$DELEUE=0+DZ1(for,cap,cum1,cum2)*LOLP-DG1(for,cap,cum2,cum3)$$
$$+\frac{N2(z14)}{3!}+\frac{DG2(for,cap,cum2,cum4)*N3(z14)}{4!}$$
$$+\frac{2*G1*DG1(for,cap,cum2,cum3)*10*N5(z14)}{6!}$$

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.

FUNCTION: DZ1

Description: DZ1 creates the coefficient for the third order term of the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$DZ1=-for*\sqrt{cum2}-.5*(-1*cum1)*for*(1-for)*cap*cum2^{-3/2}$$

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.

FUNCTION: NORM

Description: NORM finds the cumulative normal probability distribution for any value z1.

Called by: DELEUE

Calls: None.

Parameters: dens = normal density evaluated at z1

Equations:
data a/0.2316419/
data b/0.31938153,-0.356563782,1.781477937,-1.821255978,1.330274429/

$$val3 = \sum_{i=1}^{5} b_i * (\frac{1.0}{1.0 + a * z1})^i$$

where:

val3   =   intermediate value,
b   =   constant, and
a   =   constant.

$$cum = 1.0 - dens * val3$$

where:

cum   =   cumulative distribution evaluated at z1, and
dens   =   normal density evaluated at z1.

FUNCTION: DG2

Description: DG2 creates the coefficient for the fourth order term of the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$DG2 = for * cap^3 * (1 - 7 * for + 12 * for^2 - 6 * for^3)$$
$$* cum2^{-2} - 2 * cum4 * for * cap * (1 - for) * cum2^{-3}$$

where:

for   =   forced outage rate,
cap   =   size of the unit (Gigawatts),
cum2   =   second cumulant of the marginal capacity function, and
cum4   =   fourth order cumulant of the marginal capacity function.

FUNCTION: DG1

Description: DG1 creates the coefficient for the second order term of the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$DG1 = for * cap^2 * (1 - 3 * for + 2 * for^2)$$
$$* cum2^{3/2} - 1.5 * cum3 * for * cap * (1 - for) * cum2^{-5/2}$$

where:

for	=	forced outage rate,
z3	=	mean of the marginal capacity function,
cap	=	size of the unit (Gigawatts),
cum2	=	second cumulant of marginal capacity function, and
cum3	=	third cumulant of marginal capacity function.

FUNCTION: N2

Description: N2 creates the coefficient for the second order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N2 = -1 * (z2^2 - 1.0) * pinorm * Exp \frac{-z2^2}{2}$$

where:

pinorm	=	0.39894228040, and
z2	=	mean of the marginal capacity function.

FUNCTION: N3

Description: N3 creates the coefficient for the third order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N3 = -1 * (z3^3 - 3 * z3) * pinorm * Exp(\frac{-z3^2}{2})$$

where:

pinorm = 0.39894228040, and

z3 = mean of the marginal capacity function.

FUNCTION: N5

Description: N5 creates the coefficient for the fifth order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N5 = -1 * (z5^5 - 10 * z5^3 + 15 * z5) * pinorm * Exp(\frac{-z5^2}{2})$$

where:

pinorm = 0.39894228040, and

z5 = mean of the marginal capacity function.

SUBROUTINE: EMUE

Description: This subroutine calculates the coefficients for the reserve margin row. Reserve margins are calculated from the relationship

$$(\partial UE / \partial G) \cdot V(UE) = A_t \quad ,$$

where:

A_t = annual carrying cost (dollars per kilowatt per year) of the least expensive generating capacity (combustion turbine), and

$(\partial UE / \partial G) \cdot V(UE)$ = Marginal cost of unserved energy (dollars per kilowatt per year).

Substituting the Taylor series expansion of the Gram-Charlier approximation to the expression for expected unserved energy, we get

$$EUE^J = EUE^1 + \sum_i (\partial UE / \partial X_i) * (X_i^j - X_i^1) + (\partial UE / \partial L^j) * (L^j - L^1)$$

where:

EUE^J = expected unserved energy in forecast year J,

L^J = load in forecast year I, and

X_I^J = capacity of type I.

If we approximate ($\partial UE/\partial G$) by ΔUE/ΔG and note

$$\Delta G \ = \ \sum_i (X_i^j - X_i^1) + (L^j - L^1)$$

after some algebraic manipulation, we get

$$\sum_i (\partial UE/\partial X_i - A_l/V(UE)) * (X_i^j - X_i^1) + (\partial UE/\partial L_i - A_l/V(UE)) * (L_i - L_1) \ = 0$$

where:

($\partial EUE/\partial X_i$)   =   partial derivative of unserved energy for each capacity type, and

($\partial UE/\partial L_i$)   =   partial derivative of unserved energy for changes in load.

Called by: REVECP

Calls: Shavel, Deleue

Parameters: NERC = NERC region, YEAR = Forecast year

Equations:

We calculate capacity cumulants by ECP season and demand cumulants by ECP slice. These are used to calculate loss of load probability (LOLP) in each slice, and also the contribution of each capacity to the reduction of marginal unserved energy in each slice.

$$xcap = \frac{(ECUMDSP(ISP,IP,NERC) - PMDSP(ISP,IP,NERC)}{ECUNIT(IP,1)}$$

where:

xcap   =   average size of unit capacity type IP,

ECUMDSP   =   dispatchable capacity (GW) of type IP in season ISP, region NERC,

PMDSP   =   planned maintenance of capacity IP in season ISP, region NERC.

For each ECP capacity type in each season:

$$vex1 = (1 - UPFORT) * xcap$$
$$vex2 = (1 - UPFORT) * xcap^2$$
$$vex3 = (1 - UPFORT) * xcap^3$$
$$vex4 = (1 - UPFORT) * xcap^4$$

where:

UPFORT   =   forced outage rate of ECP capacity type j,

xcap   =   average size of unit of capacity type j in season I

vexk   =   moment k around 0 of capacity type j, and

$$vmom(1) = vex1$$
$$vmom(2) = vex2 - vex1^2$$
$$vmom(3) = vex3 - 2 * vex1 * vex2 + vex1^3$$
$$vmom(4) = vex4 - 4 * vex3 * vex1 + 6vex1^2 * vex2 - 3vex1^4 - 2 * vmom(2)^2$$

where:

vmom(k)   =   cumulant k of a unit of type J, season I.

We can then sum the cumulants of each capacity type to get the cumulants of the capacity density function for the season.

$$ecapcum(ISP,IMOM)=ecapcum(ISP,IMOM)+vmom(IMOM)*ECUNIT(IP,YEAR)$$

where:

ecapcum(ISP,IMOM)   =   total capacity cumulant IMOM, season ISP, and

Ecunit   =   number of plants of type L.

The cumulants of the rest of the ECP capacity types are calculated similarly. For conventional and reversible hydropower:

$$xcap=\frac{EPECAP(J,YEAR)*RNWFAC}{ECUNIT(J,YEAR)}$$

where:

EPECAP   =   capacity of renewable type J, season ISP

ECUNIT(J)   =   number of units of type J,

RNWFAC   =   capacity factor for renewable,

xcap   =   average size of unit of capacity type j in season I,

while for all other renewable capacity types

$$xcap=EPECAP(J,ISP)*EHHYCF(J,ISP)/ECUNIT(J)$$

where:

EPECAP   =   capacity of renewable type J, season ISP, year YEAR,

EHHYCF(J,ISP)   =   capacity factor for renewable J season ISP, and

xcap   =   average size of unit of capacity type J in season ISP.

$$vex1=(1-RENFOR)*xcap$$
$$vex2=(1-RENFOR)*xcap^2$$
$$vex3=(1-RENFOR)*xcap^3$$
$$vex4=(1-RENFOR)*xcap^4$$

where:

RENFOR   =   forced outage rate of EFD capacity type J,

vexk   =   moment k around 0 of capacity type J.

$$vmom(1)=vex1$$
$$vmom(2)=vex2-vex1^2$$
$$vmom(3)=vex3-2*vex1*vex2+vex1^3$$
$$vmom(4)=vex4-4*vex3*vex1+6vex1^2*vex2-3vex1^4-2*vmom(2)^2$$

where:

vmom(k)   =   cumulant k of a unit of type J, season ISP.

We can then sum the cumulants of each capacity type to get the cumulants of the capacity density function for the season.

$$ecapcum(ISP,IMOM)=ecapcum(ISP,IMOM)+vmom(IMOM)*ECUNIT(IP,YEAR)$$

where:

ecapcum(ISP,IMOM)   =   total capacity cumulant IMOM season ISP.

Ecunit   =   number of plants of type L

For each slice we calculate

$$dem = EPHGHT(VLS, YEAR) + UEITAJ(IGRP, NERC)$$

where:
$$cum(1) = ecapcum(ISP, 1) - dem$$
$$cum(2) = ecapcum(ISP, 2) + (dem * loadecpu)^2$$
$$cum(3) = ecapcum(ISP, 3)$$
$$cum(4) = ecapcum(ISP, 4)$$

cum(I)   =   cumulant of order I,

Ecapcum (ISP,IMOM)= capacity cumulant in season ISP of order IMOM, and

Loadecpu   =   fraction used to calculate load standard deviation.

We get the LOLP for this slice from calling the subroutine
$$Shavel(z1, cum(1), cum(2), cum(3), cum(4), LOLP)$$
where:

LOLP   =   loss of load probability in slice VLS.

The contribution to reduction of marginal energy is calculated for each capacity type. For dispatchable capacity
$$FOR = 1 - UPFORT(IP)$$
$$PMR = 1.0 - UPPMRT(IP) * FOR$$

where:

PMR   =   effective planned maintenance rate,

UPFORT   =   forced outage rate of capacity type IP,

FOR   =   availability rate,

UPPMRT(IP)   =   planned maintenance rate, and

where:
$$DELEMUEDSP(ISP, IP, NERC) = \sum_{VLS} \left(DELEUE(z1, cum(1), cum(2), cum(3), cum(4), xcap, FOR, LOLP) \right.$$
$$\left. - \frac{CCOSTTURB}{(8760 * ECPVOLL)} \right) * EPWIDTH(VLS) * PWR$$

DELEUE   =   contribution to reduction in marginal unserved energy from capacity IP in slice VLS,

COSTTURB   =   cost of a turbine ($/kWh),

ECPVOLL   =   value of unserved energy ($),

EPWIDTH   =   width in hours of slice VLS,

while for conventional hydroelectric sources

where:
$$DELEMUERNW(ISP, IP, NERC) = \sum_{VLS} \left(DELEUE(z1, cum(1), cum(2), cum(3), cum(4), xcap, FOR, LOLP) \right.$$
$$\left. - \frac{CCOSTTURB}{(8760 * ECPVOLL)} \right) * EPWIDTH(VLS) * RNWFAC$$

RNWFAC   =   capacity factor for hydro renewables and EPIRCCR for non-hydro renewables.

The contribution from all existing capacity is then

$$EXMUE(NERC) = \sum_{ip} delemue(ip) * epecap(ip, YEAR)$$

where:

delemue   =   contribution to reduction in marginal unserved energy of capacity type ip.

The contribution for demand is

$$LMUE(YEAR) = \sum_{VLS} (LOLP * (LCUM(VLSA, NERC, YEAR) - LCUM(VLS, NERC, 1)) * (1.0 + ADJ)$$
$$- \frac{CCOSTTURB}{8760.0 * ECPVOLL(NERC)}) * EPWDTH(VLS, YEAR)$$

where:

LMUE =   contribution to marginal unserved energy by load increase,
LCUM =   load in slice VLS region NERC forecast year YEAR,
ADJ   =   adjustment factor for revenue reconciliation,
and

$$ADJ = (DGAPOLD(NERC) - 1.0) * MEFAC(NERC)$$

where:

DGAPOLD   =   revenue gap in region NERC,
MEFAC   =   scaling factor for region NERC.

The right hand side is then

$$DELEMUERHS(YEAR, NERC) = EXMUE(YEAR) + LCUM(NERC).$$

Appendix III.D. Leadtime-Specific Hurdle Rates
Used To Forecast Electric Utility Fuel Choice

Assumptions

The objective of this appendix is to document the hurdle rates used the Electricity Capacity Planning (ECP) submodule of the Electricity Market Module (EMM) for the Annual Energy Outlook 1996 (AEO96). Utility aversion to long leadtime technologies is well known. To incorporate this aversion in the ECP, separate hurdle rates for technologies with different lead times were developed. This was done by estimating risk-premiums that were functions of lead times, and the longer the lead times, the greater would be the risk-premiums. These risk premiums were then subtracted from the overall cost-of-capital to derive leadtime-specific hurdle rates used for investment purposes.

The assumptions made in this analysis will first be discussed. Then, the methodology will be outlined. The reader is assumed to have a working knowledge of micro-economics and finance.

The first assumption deals with the nature of regulation. This analysis assumes the continuation of cost-based regulation. If utilities could recover all their operating and capital costs with certainty, all the risks are being shifted to ratepayers. Under such circumstances, in the limit, the appropriate costs and revenues would be discounted using a risk-free rate-of-return. However, over the last 15 years, the state Public Utility Commissions (PUCs) have disallowed excessive construction costs. Moreover, most commissions now have incentive programs that reward utilities for good performance and penalize them for poor performance. These programs shifted some risks from rate payers to shareholders.

Thus, full cost-recovery of all the operating costs is assumed, and, therefore, by assumption utility decision-makers will ignore all operational uncertainties. However, the PUCs are assumed to have a set of programs that shift all the construction-related risks and rewards to shareholders. Thus, this analysis will focus solely on the capital-related risks. This assumption favors natural gas-fired technologies.

Second, financial and economic theory states that the discount or hurdle rate used for investment decision-making purposes should equal the investment's cost-of-capital. If all the risks associated with building long leadtime technologies were completely diversifiable, the systematic risk and, thus, the cost-of-capital would not be a function of a plant's leadtime. This observation would suggest that the hurdle rates should be the same for short and long leadtime technologies. To estimate systematic technology-related risks, the correlation of the costs (and revenues) with the appropriate macroeconomic factors must be estimated. Such an endeavor is far beyond the scope of this project. The second assumption is that all the leadtime-specific risks are diversifiable, and, therefore the opportunity cost-of-capital will be the same for short and long leadtime technologies. This assumption favors long leadtime technologies.

However, when an uncertain investment is irreversible, the hurdle or discount rate used for capital budgeting will be greater than the opportunity cost-of-capital. More important, this wedge is a positive function of the absolute variance in costs. Thus, even if the cost-of-capital is assumed to be the same for long and short leadtime technologies, the hurdle rates could be different. This is valid if the absolute variance in the costs of long and short leadtime technologies are different. The reasons why this is true will now be discussed.

The cost data used in the ECP are actually forecasts. The longer a plant's leadtime, the longer will be the necessary forecasting horizon. That is, a plant that only takes one year to build will only require one

year forecast of costs, demand, etc. However, to estimate the cost of a plant that takes seven years to build, 7-year forecasts are needed. The precision (variance) of any forecast decreases as the forecast horizon increases. Thus, the longer the leadtime, the greater would be the variability in the estimated cost, simply because longer forecast horizons are needed.

Methodology

The methodology consists of two steps:

1. Compute the variance in capital costs as a function of lead times.
2. Use the simplest model of investment decision-making under uncertainty to compute the wedge between the cost of capital and the hurdle rate. This wedge is a function of lead times.

Each of these steps will be discussed in turn.

Step 1: Compute the variance in capital costs as a function of lead times.

To do this, a "model" must first be developed that links the relevant causal factors to total estimated construction cost. To forecast total construction costs, the overnight costs, or the cost of building a plant at a single point in time is first estimated. However, it takes several years to build a power plant and, consequently, forecasted financing charges and forecasted increases in the prices of the labor and materials used to build the power must be included. The former is typically called "interest during construction" and the latter "escalation during construction." The sum of these two items is called the time-related costs. Total project costs can be computed by adding the overnight and time-related costs.

The longer the estimated construction duration, the greater will be the time-related and total capital costs. More important, the longer the estimated lead times, the greater will be the variance in the forecasted interest and inflation rates. Thus, the greater the leadtime, the greater would be the variance in the estimated time-related and total capital costs. Thus, interest and inflation rates are two causal factors considered in this analysis.

The variability in overnight construction costs is assumed to be invariant to a plant's leadtime. If longer leadtime technologies are more complex and difficult to manage, this assumption would not be valid. There is some empirical evidence that the forecast errors in overnight nuclear construction costs are correlated with lead times. Since there were no similar analyses for other technologies, the variability in the overnight construction costs was not considered. Again, this assumption favors long leadtime technologies.

Additionally, if the utility over (under) estimates electricity demand, the value of that capacity would be less (greater) than otherwise would be the case. There are two reasons for this.   First, PUCs might disallow some or all of the costs. Second, utilities can always sell the power to others and the value of the power would be less if there was excess capacity. Thus, the greater the variance in estimated demand, the greater would be the variance in value of the capacity. The third factor is the estimated demand for electricity.

Thus, the first step is to develop a model construction costs and the value of that capacity as a function of the following three factors:
   1. Inflation rates

2. Interest rates

3. Demand for electricity

By introducing demand considerations, capital costs are adjusted for the need for the capacity. In the remainder of this paper, value-adjusted capital costs are being considered.

Step 1A: Link the levels of interest rates, inflation rates, and electricity demand to the level of costs.

The following equations were used to link total construction costs to the levels of interest and inflation rates. These equations are used in the EMM to compute total construction costs.

(1)
$$TC = X \cdot [\sum_{t=0}^{t=T} P_t \cdot [\prod_{t=t+1}^{t=T} (1+r_t) \cdot \prod_{t=0}^{t} (1+i_t)]]$$

(2)
$$P_t = t/T$$

where:

X	=	overnight construction costs
P_t	=	real cash outlays in year t of the construction period as a percent of the total number of years in the construction period T
i_t	=	the annual inflation rate in year t
r_t	=	the annual interest rate in year t
TC	=	total construction costs

To adjust construction costs for the need for the capacity, the following assumption was made. Equations 1 and 2 compute total construction costs. It was assumed that the value-adjusted construction costs would be proportional to the over (under) estimation of demand.[42] That is, if demand was corrected estimated, the value of that capacity would equal its costs. If, however, demand was overestimated (underestimated) by 10 percent, the value of that capacity would only be 90 (110) percent of the costs. Thus, total value-adjusted capital costs, TRC, is given by the following:

(3)
$$TRC = TC * (rdemand/edemand)$$

The variables <u>rdemand</u> and <u>edemand</u> denote the realized and estimated demand respectively and, thus the ratio is a measure of the forecast error. For example, if estimated demand in some future year was 10 gigawatts and realized demand for that year was only 9 gigawatts, the ratio would be .9. As a result the value of that capacity would be 90 (110) percent of its costs.

Step 1B: Compute the variance in total costs as a function of the variance in interest rates, inflation rates, and forecast errors in demand.

Equations 1-3 represents the basic "model" used. Equations 1 and 2 shows the link between interest and inflation rates and total capital costs. Equation 3 shows total value-adjusted construction costs as a function of the forecast error in demand. These three equations were included in a LOTUS 123

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[42]As will be noted below, the simplest model of investment decision making under uncertainty was used. The methodology just described is the only way to introduce demand considerations into this simple model.

spreadsheet and the Monte Carlo simulation LOTUS add-in, @RISK, was used to compute the variance in total value-adjusted costs.

The necessary inputs for the Monte Carlo simulations are assumptions about the distributions of the variables of interest. This, in turn, requires assumptions about the means and variances in interest rates, inflation rates, and demand. Interest and inflation rates were assumed to be normally distributed with means of 5 and 12 percent, respectively. The mean value of the ratio of edemand and rdemand was 1. That is, on average estimated and realized demand were assumed to equal each other.

The basic idea behind this entire analysis is that variances increase as forecast horizon increases. For a technology with a 1- year leadtime, it is only necessary to forecast interest rates, inflation rates, and electricity demand for one year. If another technology has a 4-year leadtime, one must forecast the variables of interest for four years. Crucially, the variance in 1-year forecast will be less than the variance in a 4-year forecast (i.e., the 1-year forecast will be more precise than a 4-year forecast). The variances in the three variables were constructed to be roughly consistent with a geometric Brownian-motion stochastic process. The underlying variances were based on historical data. One property of this stochastic process is that the variances increase over time.[43] The 90 percent confidence intervals for the three variables of interest as functions of the length of the forecasts are shown in Table D1. Since only three lead times were considered (3, 5, and 7 years), the estimated forecast errors were just computed for 3, 5, and 7 year forecasts of demand.

For example, Table D1 shows that the 90 percent confidence intervals for the ratio of rdemand and edemand for a 3-year forecast were .96 and 1.04, respectively. Thus, roughly speaking, there is a 90 percent probability that the ratio of the realized to estimated demand forecasted three years in the future is between .96 and 1.04. However, similar 90 percent confidence intervals for a 7-year forecast were .88 and 1.12. Given the forecast errors in electricity demand made in the 1980s, the estimates shown in Table D1 are extremely conservative.

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[43]The theory used below also assumes this stochastic process.

Table D1. 90 Percent Confidence Intervals for the Three input Variables

Forecast Errors in Demand

_____

Length of Forecast (In Years)	90 Percent Confidence Intervals
3	.96 - 1.04
5	.92 - 1.08
7	.88 - 1.12

_____

Note: See text for discussion about the units.

Inflation Rates (in Percent)

_____

Length of Forecast (In Years)	90 Percent Confidence Intervals
1	4.8 - 5.1
2	4.6 - 5.4
3	4.4 - 5.6
4	4.1 - 5.9
5	3.8 - 6.2
6	3.6 - 6.4
7	3.3 - 6.7

_____

Interest Rates (in percent)

_____

Length of Forecast (In Years)	90 Percent Confidence Intervals
1	11.8 - 12.2
2	11.4 - 12.5
3	11.0 - 13.0
4	10.7 - 13.3
5	10.4 - 13.6
6	10.0 - 14.0
7	9.6 - 14.4

_____

Table D2 shows the mean total value-adjusted capital costs, based upon an overnight construction cost of $1. This value was chosen to be consistent with the theory discussed in the next section. This table also shows the 90 percent confidence intervals and the variances errors. As expected, the precision of the cost estimates decreases as lead times increase. This is because the precision of any forecast decreases as the forecast horizon increases. Stated differently, because the precision of any forecast decreases as the forecast horizon increases, longer leadtime technologies will be more risky.

Table D2. Mean, Variance, and 90 Percent Confidence for Total Construction Costs

_____

Leadtime (In Years)	Mean	Variance	90 Percent Confidence Interval
3	1.31	.00152	1.26 - 1.37
5	1.56	.00844	1.42 - 1.67
7	1.84	.02560	1.61 - 2.05

_____

Note: Total costs based on overnight cost of $1.

Step 2: Compute the wedge between the cost-of-capital and hurdle rate as a function of the variance in the capital costs.

First-year economics and finance students are often taught to use the cost-of-capital as the hurdle rate for capital budgeting problems. However, modern theory of investment decision-making under uncertainty states that, if an investment is irreversible, there will be a "wedge" between the cost-of-capital and the appropriate hurdle rate. This wedge is a positive function of the variance in costs (and prices).

A very general model with relatively few restrictive assumptions is being developed to compute that wedge. This research is, however, not complete, and thus, for the AEO96, a simple and restrictive model is used.[44] According to this model, the wedge, γ, between the opportunity cost-of-capital, μ, and the hurdle rate, ρ, is:

$$\gamma = \frac{\varepsilon}{\varepsilon - 1}$$

$$\rho = \gamma\mu$$

$$\sigma^2 = \sigma_v^2 + \sigma_f^2 - P_{vf}\sigma_v\sigma_f$$

$$\varepsilon = \sqrt{\left(\frac{\alpha_v - \alpha_f}{\sigma^2} - \frac{1}{2}\right)^2 + \frac{2(\mu - \alpha_f)}{\sigma^2}} + \left(\frac{1}{2} - \frac{\alpha_v - \alpha_f}{\sigma^2}\right)$$

where:

σ_f	=	the standard deviation in the expected operating costs;
σ_v	=	the standard deviation in the expected capital costs;
α_f	=	the change over time in the mean operating costs;
α_v	=	the change over time in the mean capital costs;
P_{vf}	=	the correlation between the changes in operating and capital costs.

The risk premium would be ρ - μ.

For simplicity, it was assumed that all the costs were constant over time. Thus, α_f and α_v would equal zero. Additionally, since the operating costs were assumed to be recoverable, from the utility's

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[44]See, McDonald R. and Siegel, D., "The Value of Waiting to Invest," *Quarterly Journal of Economics*, November 1976. As noted above, because this model was used, demand considerations were incorporated in an ad hoc manner.

viewpoint, α_f and P_{vf} were assumed to equal zero. The opportunity cost-of-capital was assumed to be .07. The resulting risk premiums are shown in Table D3.

Table D3. Estimated Risk Premiums (in percent)

Leadtime (in Years)	Cost-of-capital	Hurdle Rate	Risk Premium
3	.07	.0776	.0076
5	.07	.0890	.0190
7	.07	.108	.0380

IV. Electricity Fuel Dispatch Submodule

Model Summary

The Electricity Fuel Dispatch Submodule (EFD) determines the annual allocation of available capacity (as determined in the Electricity Capacity Planning Submodule) to meet demand on a least-cost (merit-order) basis subject to current environmental regulations (Figure IV.1). 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 across the United States 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 Load and Demand Side Management 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 new nonutility capacity together with utility fossil-fueled and nuclear generating capacity. The EFD also incorporates the dispatch of geothermal and biomass units as well as other fossil-fueled nonutility (excluding traditional cogenerators) supply endogenously. Other renewable supply, demand-side management programs, and DSM impacts are incorporated by adjusting the demand for capacity prior to the dispatching decision, i.e. the load curve is revised[45]. Traditional cogeneration and generation from intermittent renewable technologies are determined in the demand models and renewable models, respectively, with the demand curve adjusted to incorporate their contribution to load. Existing nonutility capacity and nontraditional cogenerators are considered "must run" units which are dispatched first. 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.

The current formulation of the EFD is a linear programming (LP) algorithm that incorporates the previous Electricity Transmission and Trade Submodule into the transmission system for the LP. The LP algorithm 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.

In former versions the EFD did not incorporate interregional trade within the unit dispatching decision. It used a heuristic approach to provide a least-cost solution to allocating capacity in a region. Previously, the least-cost algorithm was solved for one region at a time based on a merit-order allocation of capacity. The regions had the option to purchase or sell energy to neighboring regions after the dispatch allocation if it was economic to do so. Regions could only purchase or sell energy to neighboring regions

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[45]Renewables included in this adjustment are municipal solid waste, wind, hydroelectric, and solar generation.

based on the remaining capacity after dispatch decisions were made. This methodology proved to be suboptimal as far as a national forecast was concerned. By formulating the LP as a national model, the solution is significantly more robust.

Another benefit of these changes is the ability to calculate the true marginal cost for each region explicitly. The marginal unit for the region can be traced to its components even if it happens to be from another region. The commercial software used for solving the linear program is used by other modules in NEMS, and there are also improved data handling capabilities and structural improvements are easier to implement.

An example of the flexibility of the LP algorithm is the ability to analyze proposed Renewable Portfolio Standards (RPS) within the dispatch decision. This constraint could not have been included during the actual dispatch decision in the previous representation of the EFD, but could only be estimated through the capacity planning portion of the model. Because of this enhancement, the model is a useful tool for studying the alternative proposals being considered.

The new representation permits geothermal and biomass units to be dispatched, and includes co-firing of coal plants with biomass. The co-firing share is determined in the ECP.

For AEO2001, distributed generation was 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). Contributions from these technologies are predetermined by the ECP because decisions to build and use this capacity considers avoided transmission and distribution costs, which are not included in dispatch decisions.

Model Purpose

Model Objectives

The objective 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 and carbon. The primary use of the EFD is to develop projections for the Energy Information Administration's *Annual Energy Outlook*.

Figure IV.1.

Electricity Fuel Dispatch & Transmission Network
Process Flow

```
                          ┌──────────────────┐
                          │    Enter EFD     │
                          └──────────────────┘
                                   │
                                   ▼
          ┌────────────────────────────────────────────────┐
          │                   Load Inputs                  │
          │   External sources, other models within NEMS,  │
          │       other submodules within the EMM          │
          │   Capacity, transmission characteristics,      │
          │   demands, fuel prices, SO2 penalty cost,      │
          │            NOx penalty cost                    │
          └────────────────────────────────────────────────┘
                                   │
                                   ▼
          ┌────────────────────────────────────────────────┐
          │                  Create Matrix                 │
          │          Determine Available Capacity          │
          │ Based on season of year, time of day, variable │
          │    O&M, fuel costs, SO2 penalty cost, planned  │
          │          maintenance and outage rate           │
          │                 Adjust Demand                  │
          │ Subject to seasonal, daily and hourly load     │
          │ fluctuations, reductions for other electricity │
          │ production from traditional cogenerators and   │
          │   nondispatchable renewable technologies       │
          │           Set up Transmission Network          │
          │  Based on interregional transmission           │
          │       characteristics and constraints          │
          └────────────────────────────────────────────────┘

                               ┌──────────────────────────────┐
                               │        Revise Matrix         │
                               │  Capacity, demands and       │
                               │  appropriate constraints are │
                               │  revised for each remaining  │
                               │  107 time slices             │
                               │  accordingly, totalling      │
                               │  one year                    │
                               └──────────────────────────────┘

    ┌──────────────────────────────────────────────────┐
    │     Solve Matrix and Retrieve Output Solution     │
    │ Record generation and fuel consumption for each   │
    │                 plant group                       │
    │        Determine marginal unit and prices         │
    │       Accumulate interregional transmission       │
    └──────────────────────────────────────────────────┘
                         │
                         ▼
                 ┌──────────────────┐
                 │  Return to EMM   │
                 └──────────────────┘
```

The EFD addresses utility and nonutility supplies endogenously; i.e. the EFD dispatches new nonutility sources[46] together with utility fossil-fuel, geothermal, biomass, and nuclear generating capacity. However, existing nonutility supply, along with nontraditional cogenerators, are considered "must run" units and are placed such that they are always dispatched. Most of these facilities have contracts with utilities to purchase power, so this treatment ensures that the model output reflects actual usage. Traditional cogeneration and intermittent renewable technologies are represented exogenously with the load curve adjusted prior to dispatching other generating technologies.

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 IV.1; see also Figure I.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 IV.1. NEMS Electricity Supply Regions

NERC Region/ Subregion	Acronym
East Central Areal 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/excluding Florida	SERC/STV
Southeastern Electric Reliability Council/Florida	SERC/FL
Southwest Power Pool	SPP
Western Systems Coordinating Council/Northwest Power Pool Area	WSCC/NWP
Western Systems Coordinating Council/ Rocky Mountain Power Area and Arizona-New Mexico Power Area	WSCC/RA
Western Systems Coordinating Council/California-Southern Nevada Power Area	WSCC/CNV

The EFD only incorporates current regulatory strategies to comply with the CAAA that can be implemented during dispatching, i.e. fuel switching. (Retrofitting units with scrubbers is represented in the ECP).

Another feature of the EFD is the ability to engage in interregional economy transactions. In the LP version of the EFD, 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

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[46]In this document, the term "nonutilities" refers to independent and small power producers, exempt wholesale generators and nontraditional cogenerators. Traditional cogenerators will be referred to specifically.

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.

Model Input and Output

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. Table IV.2 contains an overview of the input and common block work files for the EFD.

Table IV.2. Summary of Data Flows in the EFD

Input File	Common	General Description
	emmparm	EMM parameters
	parametr	NEMS parameters
ECPDAT	ecpcntl	control/switch file
	ncntrl	control/switch file
PLNTDAF	plntcntl & plntin	plant level information
ETTIN		constraints file
ETTDEM & ETT$TMP	dispett	net flows, Can. sply curve info
NUGPIPE		other cogen (not ind/comm)
SO2CNTL	uso2grp	SO2 limits and allowances
	dispin	overall inputs
ELDATYR	dispinyr	historical data overwrites
GEODATA	emmgeo	geothermal and renew capy
COGENMF & Ind/Comm modules		cogen
		cogen capy removed from load curve (ind/comm)
Various modules	control	electricity demands
CMM module	coalemm	coal prices, SO2 emissions
Various modules	qblk	price/quantities
LDSM module	dispcrv	load shapes
	bildin	build info from ECP
Various modules	fuelin	fuel quantities
	dispuse	EFD working space
	dispout	results of the EFD decision, one region, current year
		(generation, cons. & emissions)
	uefdout	Same as dispout but for all regions & years
		(reporting purposes)
	uettout	trade results
	emission	pollutant emissions
	postpr	reporting variables

Exogenous Inputs

The EFD requires cost and performance data for both existing and future units to complete the dispatch decision. This information is obtained from various EIA forms for existing units, in particular from the Form A.-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."   Likewise, 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[47]. 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 WSCC summer and winter reliability assessments.

Sulfur dioxide (SO_2), nitrogen oxides (NO_x), 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. Load shape information is also provided exogenously form the LDSM, and is based on historic load shapes.

Inputs from Other Modules [48]

The demand modules provide electricity demand by sector. These demands are aggregated and mapped to a load duration curve in the Load and Demand Side Management 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) with the resulting capacity subtracted from the load curve. Likewise, generation from intermittent renewable sources is subtracted from the load duration curve prior to the dispatch decision using capacity factors provided by the Renewable Fuels Module.

Fossil fuel prices are provided by the fuel supply modules of NEMS. These prices are used in determining variable costs for each plant type and arranging the plants in merit order. The Coal Market Module, in addition to providing coal prices, also provides a "penalty cost" proportional to the sulfur content of each coal type. This cost is used by the EMM to minimize the cost of meeting sulfur constraints.

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. It also provides the utilization rates for distributed generation capacity. The ECP provides a penalty cost for NO_x emissions based on the marginal cost of adding NO_x controls to meet emission limits.

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[47]See *Assumptions for the AEO2000* for specific technologies and sources.

[48]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.

Outputs

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 unit for each region and its cost can be easily determined. The Renewable Fuels Modules is passed generation from renewable sources determined by EMM so that total generation and fuel consumption from all renewable sources can be calculated. The fuel supply modules require the quantity of fuel consumed for the pricing of those fuels and for calculating "total" fuel use by all sectors. The EFD provides regional SO_2 removal rates to the CMM, and SO_2 emissions (computed in the CMM) to the integrating module.

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*.

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.[49] 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.

Early in the NEMS development process, models from other organizations were reviewed as possible methodologies for modeling the dispatch decision in NEMS (including trade and nonutility supply). Although an LP approach was considered at the time, LP models required considerable execution time and storage which was prohibitive even five years ago. A Lagrangian approach[50] was chosen because of its quick execution time and ability to manage many intervals for approximating the load duration curves. A full description of this heuristic modeling approach and the alternative approaches considered are reviewed in more detail in the original version of the EMM documentation.[51]

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[49]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.

[50]For a discussion of the Lagrangian approach see *Cost and Optimization Engineering*, F.C. Jelen, McGraw Hill, 1970, pages 249 - 261.

[51]Energy Information Administration, *Model Documentation: Electricity Market Module Electricity Fuel Dispatch Submodule,* DOE/EIA-M068-D (Washington, DC, March 1994)

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 implications of Title V of the CAAA in the EFD decision-making process are discussed later in this chapter in the "Fundamental Assumptions" section while the specifics of the CAAA are outlined in Appendix IV.A. The EMM also incorporates the "State Implementation Plan (SIP) Call", which specifies NO_x emission caps for 19 states in the summer season, starting in 2004.

Demand can be characterized by a load curve, which is a plot of power demand (load) versus time (Figure IV.2). 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

Figure IV.2 Typical Load Curve
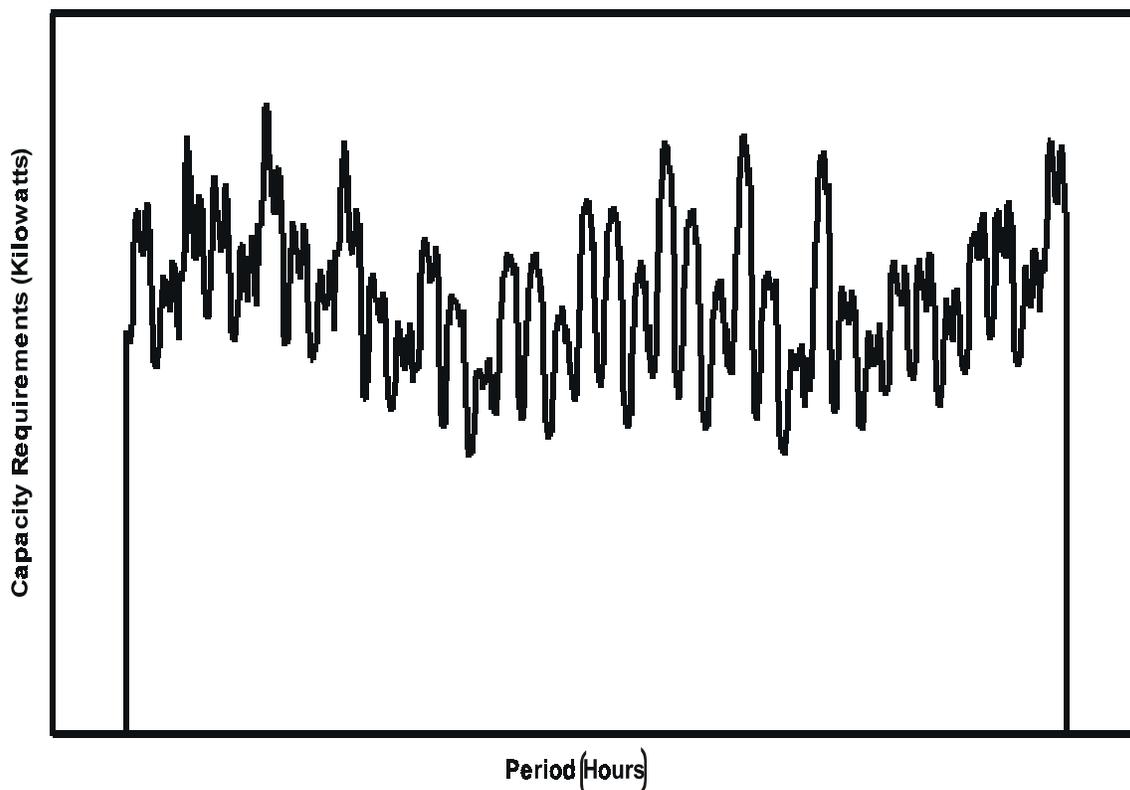
required on a continuous basis. The percent of time capacity is required at each slice of load is called a capacity factor (utilization rate). The capacity factor for the load at the base of the curve is 100 percent and it approaches 0 percent at the peak of the load curve.

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 IV.3). 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).

Figure IV.3. Typical Load Duration Curve
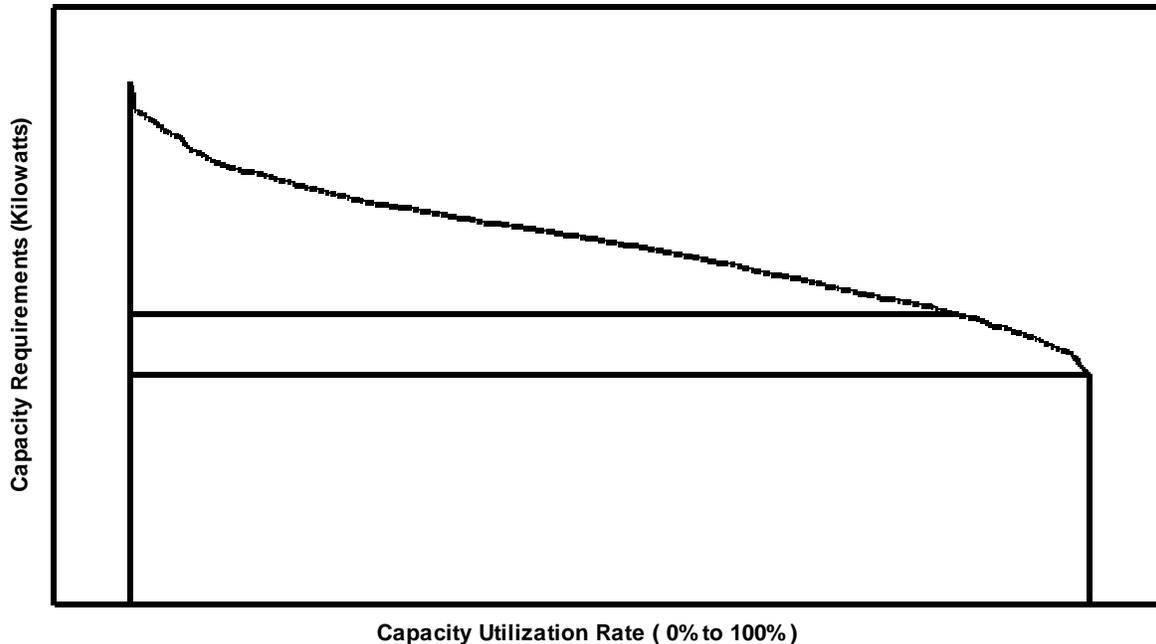
In the EFD, there are six load curves for each region with each load curve representing two months. Each load curve contains eighteen vertical slices, categorizing the load by magnitude (height) and time. The EFD dispatches available capacity to meet load in each of these slices. (Note, although the load curve re-orders the load segments, the chronology is maintained to represent maintenance scheduling for capacity and to model economy trade.)

The algorithm used for the dispatch decision is a straightforward LP formulation. It simulates the United States transmission network on the NERC region scale and simultaneously dispatches capacity[52] regionally by time slice until demand for the year is met. Capacity costs for each time slice are based on fuel and variable O&M costs. 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. Next, generation and fuel usage is determined in each area for which the capacity has been allocated. Each of the 108 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.

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[52]Note, traditional cogeneration and non dispatchable renewable capacity is removed from the load duration curve prior to the dispatch decision.

Fundamental Assumptions

The fundamental assumptions of the EFD include the representation of the Clean Air Act Amendments of 1990 (CAAA)[53] and aggregation issues related to electricity supply and demand.

While the marketable allowance program in the CAAA is economically attractive it is difficult to model. (See Appendix IV.A for a summary of the relevant provisions of the CAAA.)   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 limits set by the Clean Air Act Amendments of 1990 (CAAA). The EFD determines the total coal demand for each plant type, without regard to rank and sulfur content. The plant types are defined according to vintage. The older units (pre-1965) have a more limited flexibility to switch between coal ranks. Given these constraints, the CMM satisfies the coal demand optimally for each plant type with respect to rank and sulfur. Defined regional supply patterns in the CMM also limit ranks that can be selected to prevent, for instance, lignite from being burned in an exclusively bituminous plant. The coal module determines the least cost sulfur penalty as well as the mix of coals necessary to meet the EMM demand; the EFD determines the total demand (in Btu) for each plant type. For AEO2001, the CMM also determines banking decisions for sulfur dioxide allowances.

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. This includes only interfuel switching, since switching within coal sulfur types is accomplished within the CMM. For example, required reductions in SO_2 emissions can be accomplished by decreasing utilization of coal- or oil-fired units with comparatively high emission rates by increasing the utilization of capacity types that emit little or no SO_2 (gas-fired, nuclear, and renewable plants). This "fuel-switching" option is also available through interregional economy trade; i.e., a utility may lower its emissions by purchasing surplus power from a utility in a neighboring region which has lower emissions.

For each of the 13 electricity supply regions, the EFD also represents trading of SO_2 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

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[53]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.

overall cost of achieving the specified emissions target.

The ECP determines the additional NO_x controls needed at existing plants to meet current NO_x caps by season and state. A penalty price is set based on the marginal cost of compliance and passed to the EFD. This penalty price is included in the operating cost of each affected plant when determining the optimal dispatch.

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. Also, unit level information is not maintained by the model so projections by unit, utility or State (except New York, Florida, Texas, and California) are not available. Only aggregate results are available (by region and for the Nation). On the demand side, the load duration curve aggregates loads from many utilities to 18 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 in the planning horizon to determine the amount of capacity dispatched, fuels used, electricity trade, and costs to meet the yearly level of demand. Within each year, the EFD is executed once for each of six seasons with eighteen time slices, a total of 108 times. 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 initial matrix is created for the first iteration of season/slice demand. It is solved, modified, and then resolved for the subsequent 107 iterations representing a full year of demand. The initial matrix and objective function are created for the first peak slice and then revised for the rest of the time slices. 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. For each time slice, the capacity level is scaled to account for planned maintenance, forced outages and load following.

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,
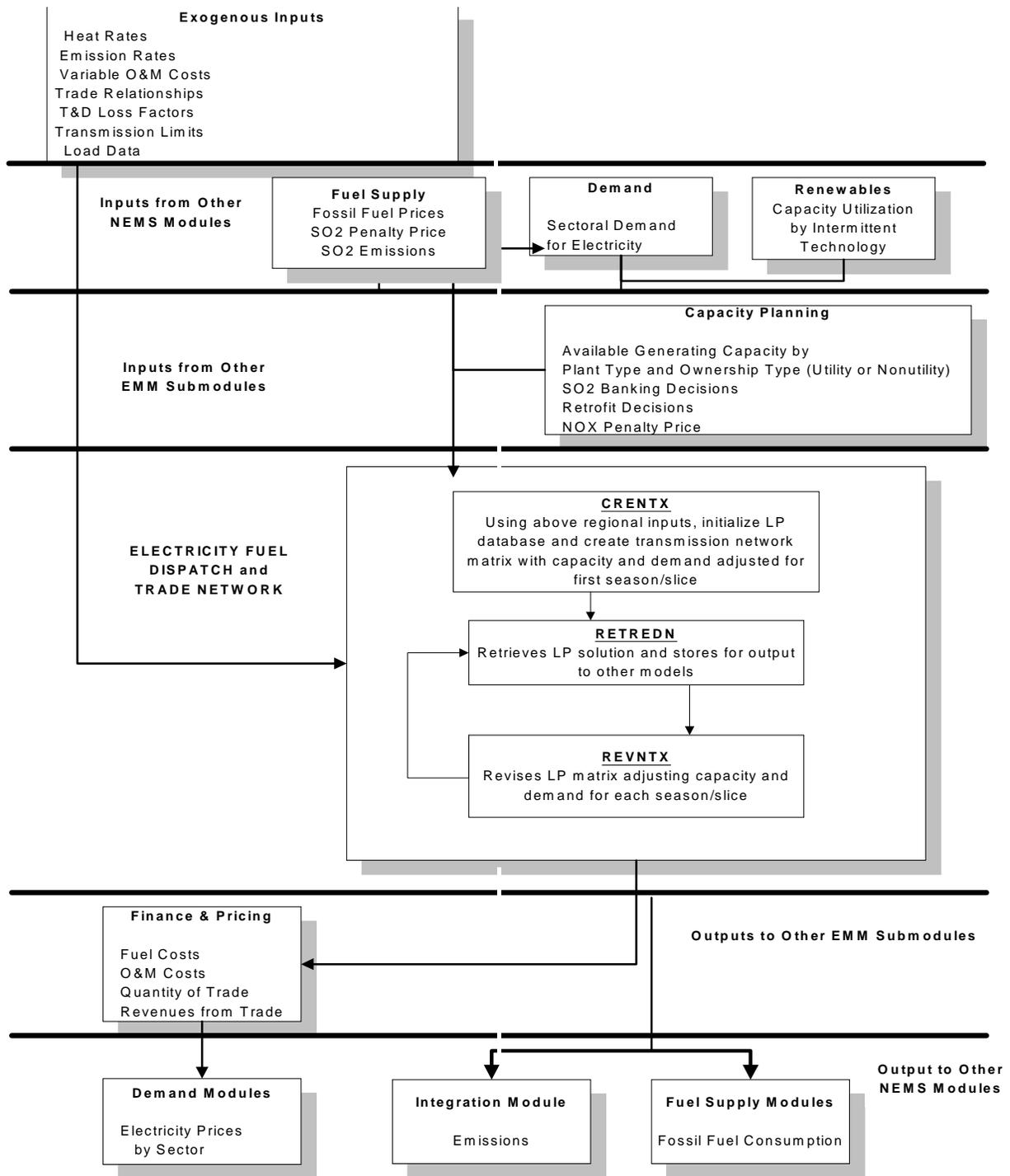
to create and store coefficients in a database, solve the problem, and retrieve the solution. The OML subroutines are not documented in this report.[54]

Logic Flow

Figure IV.4 is a flow diagram for the EFD. This flow chart includes major exogenous inputs, inputs from other modules (both NEMS and other submodules of the EMM), and the model outputs and destinations.

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

Figure IV.4. EFD Data Inputs and Outputs

Exogenous Inputs

Heat Rates
Emission Rates
Variable O&M Costs
Trade Relationships
T&D Loss Factors
Transmission Limits
Load Data

Inputs from Other NEMS Modules

Fuel Supply
Fossil Fuel Prices
SO2 Penalty Price
SO2 Emissions

Demand
Sectoral Demand for Electricity

Renewables
Capacity Utilization by Intermittent Technology

Inputs from Other EMM Submodules

Capacity Planning
Available Generating Capacity by Plant Type and Ownership Type (Utility or Nonutility)
SO2 Banking Decisions
Retrofit Decisions
NOX Penalty Price

ELECTRICITY FUEL DISPATCH and TRADE NETWORK

CRENTX
Using above regional inputs, initialize LP database and create transmission network matrix with capacity and demand adjusted for first season/slice

RETREDN
Retrieves LP solution and stores for output to other models

REVNTX
Revises LP matrix adjusting capacity and demand for each season/slice

Finance & Pricing
Fuel Costs
O&M Costs
Quantity of Trade
Revenues from Trade

Outputs to Other EMM Submodules

Output to Other NEMS Modules

Demand Modules
Electricity Prices by Sector

Integration Module
Emissions

Fuel Supply Modules
Fossil Fuel Consumption

Key Computations and Equations

This section provides the mathematical specification of the EFD. The EFD previously used a heuristic approach which was a modified version of the dispatching components of the EMM-IFFS[55]. This approach has been replaced with a linear programming algorithm which incorporates trade as well as dispatch in the cost minimization decision. As in IFFS, the EFD continues to rank available capacity in a least-cost manner, but now only uses this list to keep track of plant costs. 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 a dispatchable generating unit and transmission network. The marginal source of electricity is selected for each time slice and reacts to changes in load.[56] The demand for electricity must also be satisfied without violating certain engineering and emissions restrictions. There are environmental, load-related, capacity, and renewable portfolio constraints placed on the dispatch decisions. The EFD integrates the least cost solution with environmental compliance and engineering constraints.

The objective of the EFD is to provide an economic/environmental dispatching procedure. In an economic (least-cost) dispatch, the marginal source of electricity is selected to react to each change in load.[57] 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. Environmental issues incorporated into the NEMS include compliance with SO_2 restrictions specified in the CAAA, as discussed above in "Fundamental 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).[58] 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.

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[55]For further information on the EMM-IFFS system, refer to the following documents: Energy Information Administration, *Intermediate Future Forecasting System Executive Summary*, DOE/EIA-0430,(Washington, DC, October 1983), Energy Information Administration, *Documentation of the Integrating Module and Stock Module of the Intermediate Future Forecasting System*, DOE/EIA-M023 (Washington, DC, May 1987), Energy Information Administration, *Model Documentation: Electricity Market Module*, DOE/EIA-M002 (Washington, DC, December 1984).

[56]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.

[57]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.

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

Initial operating costs (fuel and operations and maintenance expenses) are accumulated by plant groups. A merit order is calculated by ranking the groups in ascending order of the total variable costs in order to determine the marginal plant in an efficient manner.

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. A subroutine checks to insure that the corresponding trigger points are not violated.

For each plant type, fuel consumption is computed by multiplying generation by the fuel share and heat rate for each fuel. As was done previously, SO_2 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.

Dimensions:

r	=	EMM electricity supply region
d	=	EMM electricity demand region
p	=	Dispatchable plant group
f	=	Fuel type
h	=	Vertical load slice
s	=	Season

Input Requirements

Electricity Demand
D_h	=	Height of Load Slice h (megawatts)
W_h	=	Width of Load Slice h (hours)

Fuel Specific Information
P_{rfs}	=	Price of Fuel f in Region r in Season s ($ per million Btu)
SO_{rf}	=	Quantity of Sulfur Dioxide per Unit of Fuel in Region r (pounds per million Btu)
EP	=	SO_2 Allowance Price ($ per ton) - calculated in the CMM and passed to EFD

Plant Specific Information by Capacity Grouping
R_{rp}	=	Planned Maintenance Requirement for Plant Group p and Region r (megawatts)
H_{rpf}	=	Heat rate for Fuel f used in Plant Group p and Region r (Btu per kilowatthour)
FS_{rpf}	=	Maximum Allowable Fuel Share for Fuel f in Plant Group p and Region r (fraction)
OM_{rpf}=		Variable Operations and Maintenance Cost using Fuel f in Plant Group p and Region r (mills per kilowatthour)
B_{rp}	=	Scrubber Emissions Reduction factor for Plant Group p and Region r (fraction)

CP_{rp} =   Nameplate Capacity for Plant Group p and Region r (megawatts)

NX_{rps} = NO_x emission rate for plant group p in Region r and Season s - representing only emissions restricted by a cap (pounds per million Btu)

NP = NO_x penalty price ($ per ton) - calculated in ECP and passed to EFD

Transmission Specific Information

TL_{rd} =   Transmission loss factor for energy transmitted from Region r to Region d (fraction)

TC_{rd} =   Transmission costs for energy transmitted from Region r to Region d (mills per kilowatthour)

TN_{rds} =   Transmission limits for energy trade in Season s from Region r to Region d (megawatts)

Derived Variables required

M_{rps} =   Capacity Out of Service in Season s for Planned Maintenance for Plant p in Supply Region r (megawatts)

Planned maintenance is represented as an average yearly input by capacity grouping. The total for the year is distributed over the seasons establishing a maintenance schedule for the units. The scheduled is based on the amount of time needed for each unit and the seasonal reserve margin.

1) Planned maintenance must be performed for each plant type.

$$\Sigma_s \, M_{rps} \geq R_{rp} \qquad \forall \text{ r and p}$$

S_{rpf} =   Fuel Share of Fuel f for Plant p in Region r (fraction)

The fuel share for capacity that can use more than one fuel is calculated by using the cheapest fuel up to its maximum share, followed by the next least costly, etc., until all capacity has been allocated a fuel.

2) Maximum fuel shares for multifuel plant types cannot be exceeded.

$$S_{rpf} \leq FS_{rpf} \qquad \forall \text{ r, f and p}$$

3) Each plant type consumes fuel to produce electricity and the fuel shares must sum to one.

$$\Sigma_f \, S_{rpf} = 1 \qquad \forall \text{ r and p}$$

X_{rpsh} =   Derate Factors for Plant p in Region r by Season s and Load Slice h

Calculates unit specific expected outage rates allocated by season and slice.

Load following is determined after allocating units in the first or peak slice. During off-peak periods operating levels are scaled down to reflect the practice of running plants at their minimum operating levels to prevent incurring shutoff and startup costs.

SD_{rsh} =   Adjusted load in region r, accounting for extraneous generation and firm power contracts by Season s and Load Slice h. The load for each season and slice is deducted by the amount of generation from traditional cogeneration (industrial and commercial) facilities and nondispatchable renewable units. Some of this capacity, i.e. hydroelectric, may change by season due to the intermittent nature of the plant and is removed accordingly from the appropriate time slices. The load is also incremented or decremented for exports or imports of firm power trade.

EC_{rpfs} =   Emissions Costs for Fuel Type f in Plant Group p and Region R in Session s

$$EC_{rpfs} = H_{rpf} \cdot S_{rpf} \cdot SO_{rpf} \cdot (1 - B_{rp}) \cdot EP + H_{rpf} \cdot S_{rpf} \cdot NX_{rps} \cdot NP$$

The representation of emissions restrictions, such as those specified for SO_2 in the CAAA, require additional information. Emissions cannot exceed allowable limits placed on SO_2 emissions. According to the CAAA, there are two classes of compliance groups — "affected" and "unaffected" units. Affected units are allocated allowances or permits to emit SO_2. Since allowances can be traded among affected units, the CAAA implies that the collective emissions from all affected units cannot exceed the sum of allowances. For each fuel f, the quantity ($H_{rpf} \cdot S_{rpf} \cdot SO_{rf}/2 \cdot (1-B_{rp})$) describes the SO_2 emission rate, accounting for the conversion from pounds to tons and reductions due to pollution control equipment. It is summed over the applicable fuels to provide the total tons of SO_2 per billion kilowatthour emitted by plant type p.

Restrictions on NO_x emissions are represented similarly. However, NO_x emissions are only a function of the controls at the plant and not the fuel. Since NO_x limits may be imposed seasonally, only the emissions emitted during the cap incur the penalty costs.

CST_{rps}=   Operating Costs (variable O&M and fuel) for Plant Group p and Region r in Season s (mills per kilowatthour)

$$CST_{rps} = Min \, \Sigma_f (OM_{rpf} + H_{rpf} \cdot S_{rpf} \cdot P_{rf}/1000 + EC_{rpf})$$

The fuel shares S_{rpf} specify the fraction of time alternative fuels are used in multi-fuel units. This accounts for fuel switching due to changes in the relative fuel prices or seasonal availability of fuels. For example, utility consumption of natural gas is limited in some regions during the winter because residential customers have priority over available supplies. Even though the price of gas may be less than the price of residual fuel oil, utilities may be unable to burn gas exclusively in dual-fired oil/gas plants. The variable cost is minimized by using the least expensive fuel as much as possible.

Decision Variables within the LP:

O_{rpsh} =   Utilized Dispatchable and Distributed Generation Capacity of Plant Group p in Season s and Supply Region r to Load Slice h (megawatts)

T_{rdsh} =   Utilized Transmission Capacity between Supply Region r and Demand Region d in Season s and Load Slice h.

Existing and planned transmission capacity limits are bounded (using NERC data).

Objective Function

The objective function of the dispatching algorithm minimizes total operating (fuel and variable O&M) costs and transmission costs while complying with environmental regulations. In mathematical terms, the objective function is expressed:

Minimize: $\Sigma_r \Sigma_p (CST_{rps} \cdot O_{rpsh}) + \Sigma_r \Sigma_d (TC_{rd} \cdot T_{rdsh})$ $\forall$ s, h

Multiplying per unit variable costs by O_{rpsh} produces an average operating cost per hour. Multiplying by the width of the slice, W_h in hours, corresponds to the area (energy) for load slice h. This result represents the total cost of generation for that slice.

Constraints

The objective function is subject to the following conditions and constraints:

1) Each load slice must have capacity assigned to completely satisfy its energy requirements. That is, a region's energy requirement is met by the amount of domestic capacity assigned to meet load plus the amount of energy assigned for sale to region r from all regions d (d≠r), less the amount of energy sold from region r to all regions d (d≠r). The amount imported must be adjusted for losses occurring in the transmission of power between regions.

$\Sigma_p\ O_{rpsh}\ +\ \Sigma_{d\neq r}\ T_{rdsh}\cdot(1\text{-}TL_{rd})\ -\ \Sigma_{d\neq r}\ T_{drsh}\ = SD_{rsh}\ \forall\ r,\ s\ \text{and}\ h$

2) Transmission constraint: The amount of capacity that can be assigned in region d to meet demand in region r is constrained by the interregional transmission capacity limit.

$T_{rdh}\ \leq\ TN_{rds}\qquad \forall\ r,\ d,\ s\ \text{and}\ h$

3) Allocated capacity cannot exceed available capacity, accounting for planned maintenance, forced outages and load following.

$O_{rpsh}\ \leq (CP_{rp}\text{ - }M_{rps})\cdot X_{rpsh}\qquad \forall\ r,\ p,\ s\ \text{and}\ h$

Modeling Renewable Portfolio Standards

The EFD determines the annual allocation of available capacity to satisfy electricity demand, given current environmental regulations.[59] Capacity is dispatched on a least-cost (merit-order) basis so that the most economical capacity types are utilized to the greatest extent. For each EMM region, the EFD determines the trades of renewable credits by computing the renewable generation and comparing it to the total generation (or total sales depending on the specific RPS). If the corresponding fraction exceeds the minimum RPS level, then the surplus represents the renewable credits sold. Alternatively, if the regional renewable generation is less than the required amount, then the difference represents the renewable credits bought.

The regional, total generation requirements (net imports are included since they replace domestic supplies) are computed using Equation (1):

$$ TOTGEN_r = [\sum_c \sum_o EQPGN_{rco} + \sum_i UPRNWSHR_i \cdot \sum_o EQHGN_{rio} + \sum_i UPRNWSHR_i \cdot \sum_n EQHGN_{rno} $$
$$ (1) \qquad + (ETIMPF_r + ETIMPE_r - ETEXPF_r - ETEXPE_r]\cdot 0.001 $$

where:

TOTGEN$_r$ =   Total Generation Requirement in Region r

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[59]For more information, see Energy Information Administration, *Model Documentation: Electricity Market Module, Electricity Fuel Dispatch Submodule,* DOE/EIA-M068-D (Washington, DC, March 1994).

EQPGN$_{rco}$	=	Generation by Nonrenewable Capacity Type c and Owner Type o in Region r
EQPNWSHR$_i$	=	Amount of Generation for Intermittent Renewable Capacity Type i that is Counted Towards Minimum Requirement (Fraction)
EQHGN$_{rio}$	=	Generation by Intermittent Type i and Owner Type o in Region r
UPRNWSHR$_n$	=	Amount of Generation for Dispatchable Renewable Capacity Type n that is Counted Towards Minimum Requirement (Fraction)
EQHGN$_{rno}$	=	Generation by Dispatchable Renewable Type n and Owner Type o in Region r
ETIMPF$_r$	=	Firm Power Imports in Region r
ETIMPE$_r$	=	Economy Power Imports in Region r
ETEXPF$_r$	=	Firm Power Exports in Region r
ETEXPE$_r$	=	Economy Power Exports in Region r

Next, the regional, renewable generation credited towards the RPS requirement is determined using Equation (2):

where:

$$(2) \quad RENGEN_r = [\sum_i UPRNWSHR_i \cdot \sum_o EQHGN_{rio} + \sum_n UPRNWSHR_n \cdot \sum_o EQHGN_{rno}] \cdot 0.001$$

RENGEN$_r$	=	Total Renewable Generation for RPS in Region r
UPRNWSHR$_i$	=	Amount of Generation for Intermittent Renewable Capacity Type i that is Counted Towards Minimum Requirement (Fraction)
EQHGN$_{rio}$	=	Generation by Intermittent Type i and Owner Type o in Region r
UPRNWSHR$_n$	=	Amount of Generation for Dispatchable Renewable Capacity Type n that is Counted Towards Minimum Requirement (Fraction)
EQHGN$_{rno}$	=	Generation by Dispatchable Renewable Type n and Owner Type o in Region r

Both the renewable and total generation amounts are then adjusted to include sales-to-the-grid (SALGRD$_r$) but not own-use (OWNUSE$_r$) from cogenerators. Total renewable cogeneration by region (RENCOG$_r$) is determined by summing over all sectors and renewable energy sources. The ratio of sales-to-the-grid to total cogeneration is then applied to renewable cogeneration to obtain sales-to-the-grid from renewables. That is,

$$(3) \quad RENCOG_{yr} = \sum_s \sum_f COGEN_{yrsf} \cdot SALGRD_{yr} / (SALGRD_{yr} + OWNUSE_{yr})$$

where:

RENCOG$_{yr}$ = Renewable Sales-to-Grid in Year y in Region r (billion kilowatthours)

COGEN$_{yrse}$ = Cogeneration in Year y in Region r in Sector s by Renewable Energy Source e

For each region, the achieved renewable generation fraction is determined as follows:[60]

$$(4) \quad URPSPCT_r = (RENGEN_r + RENCOG_r) / (TOTGEN_r + SALGRD_r)$$

where:

URPSPCT$_r$ = Achieved Renewable Generation Level in Region r (Fraction)

RENGEN$_r$ = Total Renewable Generation for RPS in Region r

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[60] If the RPS considers renewable generation as a fraction of sales instead of total generation, then the denominator is total regional electricity sales, in billion kilowatthours (QELASN$_r$ · 0.001).

RENCOG_r	=	Total Renewable Sales-to-Grid for RPS in Region r

RENCOG$_r$ = Total Renewable Sales-to-Grid for RPS in Region r

TOTGEN$_r$ = Total Generation for RPS in Region r

SALGRD$_r$ = Total Sales-to-Grid for RPS in Region r

The renewable generation in each region is then compared to the required level specified by the RPS (RENPCT) to ascertain the trading of credits (URPSCRD$_r$). A surplus of renewable generation (i.e., URPSCRD$_r$ greater than 0) implies that suppliers in region r are net sellers of credits. Conversely, a deficit corresponds to a net purchase. Regional trades of renewable credits are determined as follows:

$$(5) \qquad URPSCRD_r = (RENGEN_r + RENCOG_r) - RENPCT \cdot (TOTGEN_r + SALGRD_r)$$

In a given year, the applicable credit price is assumed to be the quantity-weighted average of the levelized credit prices associated with each increment of renewable generation, as expressed in Equation (6).

where:

RENEWCR$_y$ = average renewable credit price in year y (mills per kilowatthour)

EPRPSCR$_z$ = levelized credit price for incremental renewable generation in year z (mills per kilowatthour)[61]

URPSRGN$_z$ = renewable generation in year z (billion kilowatthours)

URPSRGL$_z$ = renewable generation in year prior to year z (billion kilowatthours)

The revenues associated with renewable credit trade (ERRPS) is the product of the credits traded (URPSCRD$_r$) and the average credit price (RENEWCR$_y$). In the EFD, Subroutine *ELRPSCR* determines the renewable credit trades. It also computes the regional revenue adjustments associated with the sale or purchase of credits.

Mathematical Description of Algorithms

Subroutine: ELEFD

Description:	This subroutine is the first called and control module of the EFD. ELEFD initializes variables and reads input data from DAF's, calls the LP then stores resulting output for reporting and other modules within NEMS.
Called by:	UTIL
Source:	uefd.f
Includes:	parametr,ncntrl,emission,emmparm,control,uso2grp,dispuse,dispin,dispout,dispett,uettout,
	uefdout,elout,dsmdimen,dsmtoefd
Calls:	GETSO2, GETIN, GETBLD, GETBOUT, GETOUT, ELSO2F, ELDISP, STRIN, STROUT, STRBLD, EDN, ELSO2N, EMMFUEL, STRSO2, ELRPSCR, EFDBASE
Equations:	None

Subroutine: GETSO2

---

[61] For existing renewable generation (i.e., the amount of generation prior to the initial year of the RPS), the credit price is assumed to be the levelized price for the current year. In effect, this corresponds to a spot price for existing generation, whereas the levelized price for incremental generation represents a long-term contract price.

Description:	The subroutine GETSO2 reads in total SO_2 produced from SO2DAF (DAF = direct access file) for the current year.
Called by:	ELEFD
Source:	udaf.f
Includes:	parametr, emmparm, control, uso2grp
Calls:	—
Equations:	None

Subroutine: GETIN

Description:	This subroutine reads in load curve, plant grouping, transmission constraints, and cost and performance data from the INPTDAF. The **dispin** common block is loaded only for the current model year and region with the appropriate information stored in the INPTDAF file.
Called by:	ELEFD, EDN, CRENTX, RETREDN, REVNTX, ELRPSCR
Source:	udaf.f
Includes:	parametr, emmparm, control, dispin
Calls:	—
Equations:	None

Subroutine: GETBLD

Description:	This subroutine reads in the file EBILDN which contains the build decision information that changes by region and year (including the existing and planned units) from the ECP including their cost and performance information. This data is stored in the **bildin** common block.
Called by:	ELEFD, CRENTX, RETREDN, REVNTX
Source:	udaf.f
Includes:	parametr, emmparm, control, bildin
Calls:	—
Equations:	None

Subroutine: GETBOUT

Description:	This subroutine reads in the file EBILDOUT which contains selected information from the ECP output. This data is stored in the **bildout** common block.
Called by:	ELEFD, CRENTX, RETREDN, REVNTX
Source:	udaf.f
Includes:	parametr, emmparm, control, bildout
Calls:	—
Equations:	None

Subroutine: ELDISP

Description:	This subroutine initializes additional variables, reads in interruptible international trade and adjusts the load curve for planned maintenance, renewable generation and firm trade. It calls the subroutines which are responsible for: determining the merit order; incorporating maintenance schedules; removing hydroelectric and other renewable facilities from the load curve.

Called by:	ELEFD
Source:	uefd.f
Includes:	parametr, ncntrl, emmparm, control, dispuse, dispin, dispout, dispett, dispcrv, fuelin, uettout, bildin, postpr, dsmdimen, dsmsectr, dsmunits, dsmtoefd, elcntl, elout, eftabctl, elftab, ecpcntl, plntctl
Calls:	ELMRIT, ELPNM, ELRNEW, ELFACT
Equations:	Determine the Merit Order for Dispatching
	See discussion of the Subroutine ELMRIT

Determine Planned Maintenance Schedule

See discussion of the Subroutine ELPLNM

Adjust available capacity for each time period by the planned maintenance schedule

$ECACAP(J) = (ECCAP(J,I) - ECCOPM(J,I))*.001$

$ECLFR(J) = 1.0 - (REAL(KMXCP) * EFACTR / ((1.0 - REAL(KFOR) * EFACTR) * (1.0 - REAL(KPMR) * EFACTR)))$

Where:

ECCAP = Total existing capacity

ECCOPM = Capacity Out for Planned Maintenance

KMXCP = Maximum Capacity Factor (ECMXCP)

KPMR = Planned Maintenance Rate (ECPMR)

EFACTR = Converts integer with two significant digits to a real value with four significant digits (i.e. multiplies by .001)

KFOR = Forced Outage Rate by Capacity Type (ECFOR)

Convert International Trade Power into gigawatts for each Season

International Economy Trade is currently determined exogenously, with energy estimates provided. This energy needs to be converted to gigawatts to be useful in the EFD in order to remove this energy from each slice of load.

$INTRUP = (EXPANN * (EETIME(I) / TOTHRS)) - (IMPANN * (EETIME(I) / TOTHRS))$

Where:

$IMPANN = ETIMPE / EETIME(I)$

$EXPANN = ETEXPE / EETIME(I)$

and,

ETIMPE = Economy Imports (MWh)

ETEXPE = Economy Exports (MWh)

EETIME = Number of Hours per Season

TOTHRS = Total Hours in the Year

Adjust Load Curve to Account for Firm Domestic Trade Commitments and for International Economy Trade

$ETHGHT(IVCT) = ELHGHT(IVCT,I) + EEITAJ (I) + INTRUP + EOUIPP + EOUNT$

$ETWDTH(IVCT) = ELWDTH(IVCT,I)$

Where:

EEITAJ = Net Exports (from firm power commitments and cogen)

INTRUP = Net International Economy Exports

Calculate Load (before renewables are removed from load)

The area under the curve is calculated using the midpoints of the y-values on the load duration curve.

ETAREA(IVCT) = (ETWDTH(IVCT) * (ETHGHT(IVCT))

Where:

IVCT = Load Slice Number

Remove Hydroelectric and Other Renewables from the Load Curve

See discussion of the Subroutine ELRNEW.

Calculate Load Curve for LP economic dispatch

Calculations are performed by region and season that create load requirements to send to LP to solve for.

ETAREA(IVCT) = (ETWDTH(IVCT) * (ETHGHT(IVCT))

EQLOAD = EQLOAD * ETAREA(IVCT)

Modifications to Incorporate Competitive Electricity Prices

This subroutine was modified to calculate the capacity cumulants and trade used in the reliability calculations. Because of planned maintenance, capacity is different for each season.

For each EFD capacity type in each season

$$
\begin{aligned}
vex1 &= (1 - FOR) * xcap \\
vex2 &= (1 - FOR) * xcap^2 \\
vex3 &= (1 - FOR) * xcap^3 \\
vex4 &= (1 - FOR) * xcap^4
\end{aligned}
$$

where:

FOR = forced outage rate of EFD capacity type J,

xcap = average size of unit of capacity type J in season I, and

vexk = moment k around 0 of capacity type J.

Then

 where: vmom(k) = cumulant k of a unit of type j, season i.

We can then sum the cumulants of each capacity type to get the cumulants of the capacity density function for the season.

$$
\begin{aligned}
capcum(I,IMOM,IRG,1) &= capcum(I,IMOM,IRG,1) + vmom(IMOM) * xnumplnt \\
capcum(I,IMOM,IRG,2) &= capcum(I,IMOM,IRG,2) + vmom(IMOM) * xnumplnt
\end{aligned}
$$

where:

capcum(I,IMOM,IRG,L) = total capacity cumulant IMOM season I, region IRG, type L, and

xnumplnt = number of plants of type L.

In order to create the differential for calculation of marginal unserved energy, we need to add an increment of capacity.

$$capcum(I,IMOM,IRG,2)=capcum(I,IMOM,IRG,2)+vmom(IMOM)$$

where:

vmom(IMOM) = cumulant IMOM representation of a 50 KW turbine.

We next add firm trade. Imports are treated as if they increase capacity.

$$xnumplnt=\frac{EEITAJ(IRG,I)}{xcap}$$

where:

EEITAJ(IRG,I) = firm trade (GW) for region IRG, season I,

xcap = average capacity size of a typical coal unit,

and

$$capcum(I,IMOM,IRG,1)=capcum(I,IMOM,IRG,1)+vmom(IMOM)*xnumplnt$$
$$capcum(I,IMOM,IRG,2)=capcum(I,IMOM,IRG,2)+vmom(IMOM)*xnumplnt$$

where:

vmom(k) = cumulant k of a representative coal plant, and

xnumplnt = number of coal plants of size xcap giving firm trade EEITAJ.

If trade is an export we add it to the demand cumulant

$$dcum(iblk,I,RNB)=dcum(iblk,I,RNB)+EEITAJ(RNB,I)$$

where:

dcum (iblk, ise, RNB) = demand cumulant of block iblk season I, region RNB, and

EEITAJ(RNB, I) = firm trade in season I, region RNB.

Subroutine: ELMRIT

Description:	This subroutine determines a merit order (now only used to bring order onto the plants) by listing equipment types in order of increasing operating costs. However, before the merit order is determined, the fuel shares used by each capacity type is determined based on maximum/minimum allowed and relative fuel prices.
Called by:	ELDISP
Source:	uefd.f
Includes:	parametr, ncntrl, fuelin, wwdcomon, emmparm, control, uso2grp, dispuse, dispin, dispout, dispett, ecpcntl, bildout, elout, dsmdimen, dsmtoefd, ngtdmout
Calls:	ELFSHR, EMSORT
Equations:	<u>Calculate Fuel Shares</u>

See discussion of the ELFSHR Subroutine.

<u>Calculate Unit Costs for Each Equipment Type</u>

Units costs for each equipment type are calculated by first determining total costs and then factoring the total cost by the fuel shares for each capacity group. NOTE: The fuel cost (CST_FL) is adjusted for carbon penalty, RPS credits, and biomass cofiring as necessary.

CST_TOT = CST_OM + CST _FL + CST_SO2 + CST - NO_x

Where:

CST_OM = ECOMR(I,J)

CST_FL = ZCFL*ECHTRT(I,J) * .001

CST_SO2 = PSO2 * ZSO2 *.000001 * ECHTRT(I,J) * (1.0 - REAL(KSCRB) * EFACTR)

$CST\_NO_x = PNO_x * ZNO_x = 0.000001 * ECHTRT (I,J)$

and,

ECOMR = Variable O&M

ZCFL = UPFUEL = Delivered Fuel Prices

ECHTRT = Heat rate

$PSO2 = EPSO2 = SO_2$ Penalty Cost

$ZSO2 = UFRSO2 = SO_2$ Emission Rate

$PNO_x = EPNOXPR = NO_x$ penalty price

$ZNO_x = ECFNOXC = NO_x$ emission rate amount contributing toward cap

KSCRB = ECSCRB = Scrubber Efficiency

UNTCST(I) = UNTCST(I) + ECFSHR(I,J) * CST_TOT (Total Costs multiplied by fuel share)

<u>Sort by Unit Costs</u>

See discussion of the EMSORT subroutine.

Subroutine: EMSORT

Description:	The costs are sorted by creating an index which refers to the order. The sort is executed by searching through the costs to find the smallest cost and assigning this capacity group and index of one. This sort is executed with the remaining capacity groups, finding the next smallest cost, until the sort is complete.
Called by:	ELMRIT
Source:	uefd.f
Includes:	emmparm
Calls:	—
Equations:	None

Subroutine: ELFSHR

Description:	This subroutine calculate fuel shares by determining first if an equipment type is dual-fired or not. If the equipment type is dual-fired, then the cheapest fuel is used up to its maximum share, followed by the next least costly, etc., until all the capacity is allocated. If the equipment type (coal) is allowed to cofire with biomass the share is set to the ECP share.
Called by:	ELMRIT, CRENTX, RETREDN
Source:	uefd.f
Includes:	parametr, ncntrl, emmparm, control, wwdcomon, dispuse, dispin, dispout, fuelin, uefdout, uso2grp, ecpcntl, bildout, elout, dsmdimen, dsmtoefd, ngtdmout
Calls:	—
Equations:	<u>Determine Weights for Seasonal Fuel Shares</u>
	SWGHT(JSP) = EETIME(JSP)/8760 * ECCAP(I,JSP)
	TWGHT = TWGHT + SWGHT(JSP)
	Where:

EETIME = Number of Hours per Season
ECCAP = Conventional Capacity
I = Capacity Type
JSP = Season
SWGHT(JSP) = SWGHT(JSP) / TWGHT
FSHR = FSHR + ECFSHR(I,J)
ECFSHR(I,J) = ECFSHR(I,J) / FSHR
Where,
J = Fuel Type
ECMFSH = Maximum Fuel Share

If the Capacity is Dual-Fired, Determine Shares

First, Sort by Costs

If Prices are Close, Smooth Shares Between Fuels

If the Capacity is Dual-Fired, Use the Maximum Fuel Share for the Cheapest fuel, and adjust the Other Shares so that Total Share Equals 1
ECFSHR(I,IR(J)) = MIN(ECFSHR(I,IR(J)),FSHR)
FSHR = FSHR - ECFSHR(I,IR(J))

Subroutine: ELPLNM

Description:	After the merit order has been determined, a maintenance schedule is determined for the units. This maintenance schedule is based on the seasonal reserve margin, with the maintenance scheduled from the smallest to the largest units.
Called by:	ELDISP
Source Code:	uefd.f
Includes:	parametr, ncntrl, emmparm, control, dispuse, dispin, dispout, dispett, dispcrv, bildout, ecpcntl, dsmsectr, dsmtoefd, dsmdimen
Calls:	—
Equations:	Calculate Capacity Required to Meet Peak Demand in Each Time Period and Average Over All Time Periods

In this section, the y-value (demand) of the xy pair that describes the load is adjusted by International economy exports, planned domestic trade transactions and purchases from cogenerators and interregional transmission constraints to most accurately portray planned maintenance schedules.

INTRUP = EXPANN*(EETIME(ISP)/TOTHRS)) - (IMPANN*(EETIME(ISP)/TOTHRS))

Where:

IMPANN = ETIMPE/TOTHRS

EXPANN = ETEXPE/TOTHRS

ETIMPE = Economy Imports (MWh)

ETEXPE = Economy Exports (MWh)

TOTHRS = Total Hours in Year

EETIME = Total Hours in Season

ADJUST(ISP) = INTRUP + EEITAJ(ISP)

PEAK(ISP) = ELPEAK(1,ISP) + INTRUP + EEITAJ(ISP)

Where:

ELYVAL = Y value on original demand curve (GW), where X is time and Y is GW.

EEITAJ = Net Exports

DEMAND = PEAK(ISP) * EETIME(ISP) + DEMAND

Calculate and Add in Available Hydroelectric Capacity

CAP(ISP) = CAP(ISP) + EHCAP(IRNEW,ISP) * .001 * EETIME(ISP)

TOTAL = TOTAL + CAP(ISP)

Calculate Required Capacity Utilization Lost to Planned Maintenance and Sum Total Available Capacity

If the Planned Maintenance Rate is greater than zero then:

RQ = ECCAP(IPLNT,ISP) * REAL(KPMR) * EFACTR * EETIME(ISP) * 0.001

Where:

ECCAP = Conventional Capacity

KPMR = Planned Maintenance Rate

EETIME = Time in Season

If the Planned Maintenance Rate is zero then:

RQ = ECCOPM(IPLNT,ISP) * EETIME(ISP) * 0.001

Where:

ECCOPM = Capacity Net of Planned Maintenance

REQIR = RQ + REQIR

CAP(ISP) = ECCAP(IPLNT,ISP) * 0.001 * EETIME(ISP) + CAP(ISP)

TOTAL = ECCAP(IPLNT,ISP) * 0.001 * EETIME(ISP) + TOTAL

Determine the Maximum Reserve Margin Which Can Be Achieved

EEMRM = MAX(DBLE(0.0),((TOTAL - REQIR) / DEMAND - DBLE(1.0))

Determine Seasonal and Annual Maintenance Time Availability Measured in Potential Energy Lost to Maintenance

Available time is calculated as total capacity less the maximum reserve margin and capacity scheduled for maintenance

AVAIL(ISP) = CAP(ISP) - PEAK(ISP) * (1+EEMRM) * EETIME(ISP) - SCHDLD(ISP)

TOTAVL = TOTAVL + AVAIL(ISP)

Schedule Maintenance from the Seasonal Period with the Largest Reserve Margin to the Seasonal Period with the Smallest Reserve Margin

Maintenance is scheduled for capacity based on the minimum of remaining time available during the season for planned maintenance (AVAIL) and the planned maintenance time necessary for the unit.

ECCOPM(IPLNT,ISP) = MIN(AVAIL(ISP),RQ,DBLE(ECCAP(IPLNT,ISP) * EETIME(ISP) * .001)

AVAIL(ISP) = AVAIL(ISP) - ECCOPM(IPLNT,ISP)

Total available and total required are calculated to determine remaining scheduling.

TOTAVL = TOTAVL - ECCOPM(IPLNT,ISP)

RQ = RQ-ECCOMP(IPLNT,ISP)

Subroutine: ELRNEW

Description: This subroutine removes the hydroelectric and other renewable units from the load curve, with the capacity removed in the appropriate slices to meet their capacity factor requirements. The resulting generation is maintained for reporting and to be passed to the Renewable Fuels Module.

Called by: ELDISP

Source Code: uefd.f

Includes: parametr, emmparm, control, ncntrl, dispuse, dispin, dispout, dispcrv, dispett, fuelin, elout, ecpcntl, elcntl, dsmsectr, dsmunits, dsmdimen

Calls: —

Equations: The purpose of this section is to describe how hydroelectric and other renewable generating capacity is dispatched (operated). Hydroelectric and other renewable capacity typically has the lowest variable cost (since its fuel, water, wind, sun, etc. is considered to have no cost), which implies that it would be the first plant type placed on the curve so that its utilization is maximized. However, hydroelectric plants generally cannot be operated as baseload capacity because their output is constrained by the available water supply.

In the EFD, hydroelectric generating capacity is dispatched before other plant types in order to insure that the energy constraint is satisfied. Subsequently, the other dispatchable plant types are then allowed to meet this load, excluding the portion met by hydroelectric generating capacity.

The energy constraint is incorporated using an average utilization rate for hydroelectric plants, which specifies the fraction of time water is available to operate these plants. For example, a utilization rate of 0.50 indicates that the average hours of operation, would be limited to 4,380 of the total 8,760 hours in this example. Currently, the utilization rates for hydroelectric plants are based on historical data. If regulations to protect fish by restricting water flow are enacted then these utilization rates would be adjusted downward. The total energy (S_AREA) that could be produced by the available hydroelectric capacity is given by the following equation.

Determine Capacity and Energy to Remove from Load Curve

The capacity of the renewable type is to be removed from the load curve unless the renewable capacity is greater than the load.

R_CAP = MIN(DBLE(EHCAP(IRNW,ISP)) * DBLE(0.001), ETHGHT(IVCT))

R_AREA = EHCAP(IRNW,ISP) * 0.001 * HOURS

S_CAP = R_CAP

Where:

EHCAP(IRNW,ISP) = Renewable Capacity

ETHGHT = Height of seasonal load duration curve

HOURS = Hours associated with renewable Capacity Factor

The model places the hydroelectric capacity using a trigger point, which indicates where on the load duration curve placement is initiated such that the energy constraint can be matched while using all of the capacity. There are three possible cases where both of these objectives can be satisfied:

• All of the capacity is used for base load (i.e. placement is entirely below the knee)

• None of the capacity is used for base load (i.e. placement is between the knee and the peak)

• Some of the capacity is used for base load (i.e. placement begins below the knee but extends above it).

The minimum amount of energy that could be generated while allocating all of the capacity (A_MIN) occurs when the capacity is placed at the top of the curve. The maximum amount that could be produced (A_MAX) results by operating the capacity at the bottom of the curve. Therefore, in order to meet the energy constraint while allocating all of the capacity, the product of the available hydroelectric capacity and the average utilization rate must be greater than or equal to A_MIN and less than or equal to A_MAX.

However, there may be some instances where it may not be possible to allocate all of the available hydroelectric capacity such that the assumed utilization rate is achieved. Consequently, the following cases are also considered in the EMM:

• The assumed utilization rate for hydroelectric plants results in generation S_AREA/R_AREA) that is less than the minimum output (A_MIN)

• The assumed utilization rate for hydroelectric plants results in generation that is greater than the maximum amount (A_MAX).

Modifications to Incorporate Competitive Electricity Prices

This subroutine was modified to calculate the capacity cumulants of the renewable EFD capacity types and add them to the generating capacity cumulants. Because of seasonal factors for some renewables, capacity is different for each season.

For conventional and reversible hydropower

$$xcap = EHCAP(J,ISP) * RNWFAC/EHUNIT(J)$$

where:

EHCAP = capacity of renewable type J, season ISP,

RNWFAC = capacity factor for renewable, and

xcap = average size of unit of capacity type j in season I,

while for all other renewable capacity types

$$xcap = EHCAP(J,ISP) * EHHYCF(J,ISP)/EHUNIT(J)$$

where:

EHCAP = capacity of renewable type J, season ISP

EHHYCF(J,ISP) = capacity factor for renewable J, season ISP

xcap = average size of unit of capacity type J, in season ISP.

$$vex1 = (1 - RENFOR) * xcap$$
$$vex2 = (1 - RENFOR) * xcap^2$$
$$vex3 = (1 - RENFOR) * xcap^3$$
$$vex4 = (1 - RENFOR) * xcap^4$$

where:

RENFOR = forced outage rate of EFD capacity type J,

vexk = moment k around 0 of capacity type J.

$$vmom(1) = vex1$$
$$vmom(2) = vex2 - vex1^2$$
$$vmom(3) = vex3 - 3 * vex1 * vex2 + 2 * vex1^3$$
$$vmom(4) = vex4 - 4 * vex3 * vex1 + 6vex1^2 * vex2 - 3vex1^4 - 3 * vmom(2)^2$$

where:

vmom(k) = cumulant k of a unit of type J, season ISP.

We can then sum the cumulants of each capacity type to get the cumulants of the capacity density function for the season.

$$capcum(I,IMOM,IRG,1) = capcum(I,IMOM,IRG,1) + vmom(IMOM) * xnumplnt$$
$$capcum(I,IMOM,IRG,2) = capcum(I,IMOM,IRG,2) + vmom(IMOM) * xnumplnt$$

where: capcum(I,IMOM,IRG,L) = total capacity cumulant IMOM, season I, region IRG, type L.

xnumplnt = number of plants of type L.

Subroutine: ELFACT

Description:	This subroutine determines the load factors needed to calculate unit specific derate factors.
Called by:	ELDISP
Source:	uefd.f
Includes:	emmparm
Calls:	—
Equations:	After the dispatch in the peak slice units need to lower operating levels to simulate off-peak times and avoid shutting off and starting 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.

Subroutine: STRIN

Description:	This subroutine stores data needed for the dispatch decision in a direct access file
Called by:	ELEFD
Source:	udaf.f
Includes:	parametr, emmparm, control, dispin, dispina
Calls:	—
Equations:	None

Subroutine: STROUT

Description:	This subroutine stores the results of the dispatch decision in a direct access file

Called by: ELEFD
Source: udaf.f
Includes: parametr, emmparm, control, dispout
Calls: —
Equations: None

Subroutine: STRBLD

Description: This subroutine stores the build decision information in a direct access file ECPIDAF.
Called by: ELEFD
Includes: parametr, emmparm, control, bildin
Calls: —
Equations: None.

Subroutine: EDN

Description: This subroutine is the main controlling subroutine for the LP process. It determines whether the matrix should be created or revised depending on iteration, year, season and slice. It also calls the subroutine to retrieve the results.
Called by: ELEFD
Includes: parametr, emmparm, control, ncntrl,dispin
Calls: GETIN, CRENTX, RETREDN, REVNTX
Equations: None.

Subroutine: CRENTX

Description: This subroutine creates the matrix and optimizes the LP in the first season/slice in the first iteration of each year. This subroutine essentially allocates the "dispatchable" capacity by capacity type for the peak seasonal load. It also calls the subroutine to pack the results of the LP solution for debugging.
Called by: EDN
Includes: parametr, emmparm, control, ncntrl, dispin, omlbuf, dfinc2, wfinc2, emmparm, dispout, dispuse, dispett, fuelin, elout, uso2grp, postpr, cdsfmgr, ecpcntl, udatout, bildout, eusprc, efpint
Calls: GETBOUT, GETIN, GETBLD, ELFSHR, ELDRAT
                (Note: calls for OML subroutines not discussed.)
Equations: The renewable portfolio constraint goal is first computed using the ratio of the slice height to the average height.
                $RPSRHS = QELASN(MNUMNR,CURIYR) / 8760.0 * (HGTHS / (TGEN / 8760))$
                Where:
                QELASN=Electricity demand by MNUMNR (Nerc Region) and CURIYR (year)
                HGTHS=Height of all slices
                TGEN=Total generation

                The capacity of each plant is derated (see ELDRAT subroutine) and the capacity available for the time slice is accorded a column in the matrix. The upper bound on the column is calculated:

                $AVCAPY=ABS(ECCAP(PL,SEASON)-ECCOPM(PL,SEASON)) * 0.001 * DRAT$
                Where:

ECCAP=Capacity available by PL (plant group) and SEASON

ECCOPM=Capacity out for planned maintenance by plant group and season

DRAT=Percent of year plant is down

If the plant is must-run then the lower bound is set equal to the upper bound. The cost for each plant is accumulated in the COST row (previously calculated in ELMRIT subroutine.)

The available capacity columns are then intersected with the appropriate electricity supply row depending on the minimum capacity factor for that capacity type/group (ECCFBD(JCAP,2)) (in general, this value is equal to .08 for baseload and intermediate units.) This value signifies the point where baseload and intermediate capacity are no longer available and peak capacity is required (i.e., only peaking units can be dispatched beyond this point so the algorithm needs to check if the capacity is a baseload, intermediate or peaking unit) Due to the way the EFD data was used in the previous configuration of the model the electricity supply rows had to be split between capacity that can be used for either base and intermediate OR for base, intermediate, and peaking. Then a constraint is imposed on how much base capacity can be used in each slice; thus preventing ramping up and down of the large baseload plants. For instance, baseload nuclear plants are allowed to run in the base and intermediate supply slices, but, generally more expensive, gas combined cycle plants are allowed to run in the base, intermediate and peak load slices.

PKPOINT=ELHGHT((I-1),SEASON)

LOAD=ETHGHT(SLICE,SEASON,SIRG)

PKLOAD=LOAD- PKPOINT

Where:

ELHGHT = Height of seasonal load curve

I = Number of points in load curve

SIRG= Supply region

The base capacity constraint is equal to the PKLOAD.

Note: not all slices have capacity requirements above the peakpoint; generally only 2% of total load is peaking.

The transmission network columns are constructed now, enabling the electricity supply rows to meet electricity demand rows. Flows across the network are based on regional transmission limits. Costs are calculated:

TRANCOST=PTHRESH1(CURIYR,SIRG,DIRG) + PTHRESH2(CURIYR,SIRG,DIRG) + BARRIER(CURIYR)

Where:

CURIYR=year

PTHRESH1=Threshold cost 1 by SIRG (supply region) and DIRG (demand region)

PTHRESH2=Threshold cost 2 by SIRG (supply region) and DIRG (demand region)

BARRIER=Hurdle rate

Note: There is no transmission limit or cost on transmission within a region.

Create structure for economy trade and transmission from Canada and Mexico. Electricity supply rows are set up for base and intermediate and linked to columns created for each supply step of available capacity (treated similar to plant capacity). Canadian electricity supply rows are then linked through a transmission network of columns to possible US demands. Constraints on transmission flows are based on international transmission limits.

The model is then solved with the OML optimizer.

while the y-value is the corresponding value on the load duration curve. This y-value signifies the point where baseload and intermediate capacity are no longer available and peak capacity is required (i.e., only peaking units can be dispatched beyond this point so the algorithm needs to check if the capacity is a baseload, intermediate or peaking unit). The subroutine ELGETY is called to determine this y value and the step number of the trigger point on the load duration curve.

Subroutine: RETREDN

Description:	This subroutine retrieves the optimized solution of the LP for one season and slice and stores them for reporting and use in other modules.
Called by:	EDN
Includes:	parametr, emmparm, control, ncntrl, dispin, omlbuf, dfinc2, wfinc2, emmparm, dispout, dispuse, dispett, fuelin, elout, uso2grp, postpr, cdsfmgr, ecpcntl, udatout, bildout, eusprc, efpint
Calls:	GETBOUT, GETIN, GETOUT, GETBLD, ELFSHR, ELDRAT, ELCOST, LOADNG, STROUT, STRBLD
	(Note: calls for OML subroutines not discussed.)
Equations:	None.

Subroutine: REVNTX

Description:	This subroutine revises the matrix and optimizes the LP for all the following season/slices in the each subsequent iterations of each year. This subroutine essentially allocates the "dispatchable" capacity by capacity type for the off-peak seasonal load. It also calls the subroutine to pack the results of the LP solution for debugging (only when necessary.)
Called by:	EDN
Includes:	parametr, emmparm, control, ncntrl, dispin, omlbuf, dfinc2, wfinc2, emmparm, dispout, dispuse, dispett, fuelin, elout, uso2grp, postpr, cdsfmgr, ecpcntl, udatout, bildout, eusprc, efpint
Calls:	GETBOUT, GETIN, GETBLD, ELFSHR, ELDRAT
	(Note: calls for OML subroutines not discussed.)
Equations:	This subroutine mimics the CRENTX subroutine for the following 107 slices. It revises the matrix for each of the steps in the CRENTX that is determined according to the amount of time in the season/slices.
Equations:	For each native capacity and generation amount, all the export capacity and generation that is available in the same vertical slice (seasonal and time of day time period) is considered for a potential trade. In order for trade to occur, the following conditions must be met:

- The cost of buying from another region must be less than the cost of producing at home. COSTEX < COSTNV

- The difference between the native cost and the export cost must be greater than the price threshold.
- The potential export region must be one that can physically trade with the import region. (This is determined by looking up the records in the Constraints File.)
- If the 2 regions are trading regions, there must also be room in the pipeline (i.e. all the constraint values not used up yet by contracts).

CALL ELGETY(XPVPNT(MNTRGR),YVAL,IVAL) — See description of the subroutine ELGETY

Where:

XPVPNT = Maximum Capacity Factor Bounds

MNTRGR = Trigger Number

YVAL = Y value on the load duration curve

IVAL = Step number

Capacity Switch:

Determines if Capacity is Available and/or the capacity factor is within range (i.e. greater than 0 and less than 1).

Check if Capacity Can Operate at this Utilization Level

Determine Next Trigger Point which Impacts Current Capacity

Update Intercept and Slope of Current Cutting Line — Call Subroutine ELDRAT

See discussion of the ELDRAT subroutine.

ESLCUT(2) = slope of the cutting line

Subroutine: ELDRAT

Description: This subroutine determines unit specific derate factors

Called by: CRENTX, RETREDN, REVNTX

Source Code: uefd.f

Includes: parametr, emmparm, control, dispin, dispuse

Calls: —

Equations: Drate factors are calculated:

FOR = ECFOR(IP) * EFACTR

DRAT(VLS) = FOR * (1 - (LFR * EETIME(ISP) * FAC(VLS) / ETWDTH(VLS))

Where:

ECFOR = Displaced plant group outage rate

EFACTR = Real conversion factor

LFR = Percent of year down due to load following

ETWDTH = Width of seasonal load curve

VLS = Number of points in load curve

Subroutine: ELCOST

Description: This subroutine tabulates fuel consumption, fuel costs and O&M costs associated with a set of dispatch decisions.

Called by: RETREDN

Source Code: uefd.f

Includes: parametr, emmparm, dispuse, dispin

Calls: —

Equations: <u>Add Plant Group Data to Running Totals</u>

Capacity
$$ECAPPS(IPGRP,ISP) = ECAPPS(IPGRP,ISP) + ECDSPC(I)$$
Where:
ECDSPC = Capacity in Each Horizontal Slice

Generation Totals — By Season and Ownership
$$GEN = ECDSPE(I) * EETIME(ISP)$$
$$ETGEN = ETGEN + GEN$$
$$EQPGN(IPGRP,IFOWN) = EQPGN(IPGRP,IFOWN) + GEN$$
$$EGENPS(IPGRP,ISP) = EGENPS(IPGRP,ISP) + GEN$$
Where:
ECDSPE = Energy in each Horizontal Slice
I = Horizontal Slice
EETIME = Hours in Seasonal Slice
IFOWN = Ownership Type (Utility, Nonutility)
ISP = Season

<u>Calculate Fuel Consumption, Emissions and O&M Costs</u>

Fuel Consumption
$$FUEL = GEN * ECFSHR(N,IFP) * ECHTRT(N,ISP) * 0.001$$
Where:
GEN = Energy Generated
ECFSHR = Fuel Share
N = Plant Group
IFP = Fuel Type
ISP = Season

Total Fuel Consumption by Plant Type and by Fuel Type and Ownership
$$EQPFL(IPGRP) = EQPFL(IPGRP) + FUEL$$
$$EQFFL(IFLTP,IFOWN) = EQFFL(IFLTP,IFOWN) + FUEL$$

<u>Aggregate Totals</u>
This section outlines the equations for determining the aggregate totals of the dispatch decision. The following describes the totals by NERC region, plant type and ownership

type (utility and nonutility). Totals by Census division and fuel supply regions and by fuel type are calculated in the same manner, only the totals are maintained by a different dimension.

Generation
UQPGENN(IPGRP,INR,IFOWN) = UQPGENN(IPGRP,INR,IFOWN) + GEN * ECFSHR(N,IFP)

Consumption
UQPCONN(IPGRP,INR,IFOWN) = UQPCONN(IPGRP,INR,IFOWN) + FUEL

Variable O&M
ERTOM(IFOWN) = ERTOM(IFOWN) + GEN * ECFSHR(N,IFP) * ECOMR(N,IFP) * 0.001

Where:
GEN = Energy
FUEL = Fuel Consumption
ECOMR = Variable O&M

SO_2 Emissions
EQPSO2(IPGRP) = EQPSO2(IPGRP) + FUEL * UFRSO2(IFLTP,IFLRG) * (1.0 - UFRASH(IFLTP,IFLRG)) * (1.0 - REAL(KSCRB) * EFACTR) * 0.5

NO_x Emissions
EQPNOX(IPGRP) = EQPNOX(IPGRP) + FUEL * NOXFAC * 0.5

CO_2 Emissions
EQPCO2(IPGRP) = EQPCO2(IPGRP) + FUEL * UFRCO2(IFLTP) * 0.5

Carbon Emissions
EQPCAR(IPGRP) = EQPCAR(IPGRP) + FUEL * UFRCAR(IFLTP) * 0.5

CO_1 Emissions
EQPCO1(IPGRP) = EQPCO1(IPGRP) + FUEL * UFRCO1(IFLTP) * 0.5

VOC Emissions
EQPVOC(IPGRP) = EQPVOC(IPGRP) + FUEL * UFRVOC(IFLTP) * 0.5

Where:
IFLTP = Fuel Type
INR = NERC Region
UFRSO2 = SO2 Emission Rate
UFRNOX = NOx Emission Rate
UFRCO2 = CO2 Emission Rate
UFRCAR = Carbon Emission Rate

UFRCO1 = CO1 Emission Rate
UFRVOC = VOC Emission Rate
FUEL = Fuel Consumption
IFLTP = Fuel Type
KSCRB = Scrubber Efficiency

Subroutine: LOADNG

Description:	This subroutine computes the revenues associated with nonutilities including exempt wholesale generators, small power producers (Renewables) and commercial, industrial and other cogenerators/facilities for the EFP.
Called by:	RETREDN
Source Code:	unugs.f
Includes:	parametr, ncntrl, emmparm, control, dispuse, dispin, dispout, dispett, cogen, postrp
Calls:	—
Equations:	Calculate Nonutility (EWG — Not Cogen) Renewable and Total Renewables (including Utilities) Total O&M Expense

HOMALL = HOMALL + ERHOM(I,J)

LOCRNW = LOCRNW + ERHOM(I,3)

EWGRNW = EWGRNW + LOCRNW

Where:

ERHOM = Variable O&M

I = Renewable Technology Type

J = Ownership Type; 1 & 2 = Utility; 3 = Nonutility

3 = Ownership Type = 3; i.e. nonutility

Calculate Total Nonutility Renewable Generation

TOTGENR = TOTGENR + EQHGN(I,3)

Where:

EQHGN = Generation

I = Renewable Technology Type

3 = Ownership Type; i.e., nonutility

Calculate Utility, Total (Utility plus nonutility) and Nonutility Variable Costs

TOTREV = TOTREV + (ERTFL(I) + ERTOM(I))

LOCEWG = LOCEWG + ERTFL(3) + ERTOM(3)

INTNCOST = INTNCOST + (ERTFL(1) + ERTFL(2) + ERTOM(1) + ERTOM(2)) + (HOMALL -EWGRNW)

Where:

ERTFL = Total Fuel Cost

ERTOM = Variable O&M

I = Ownership Type; 1 & 2 = Utility; 3 = Nonutility

Calculate EWG Revenues and Price

Total EWG Revenues are equal to the fixed plus the variable component. The fixed component (EWGFIX) is determined in the ECP where the capacity expansion decision is determined.

EWGREV = EWGFIX + LOCEWG

EWGAVP = TOTREV / TOTGEN

EWGFIX = EWG Fixed (Capital) Component

Calculate Commercial Nonutility Revenues (Sold to Utilities)

Calculate Generation and Capacity Sold to Utilities

TOTGENC = TOTGENC + (CSHARE(IRG,I) * (GRIDSHR(I,IYR)*(CGCOMGEN(I,IYR,J))))

TOTCAPC = TOTCAPC + (CSHARE(IRG,I) * (GRIDSHR(I,IYR)*(CGCOMCAP(I,IYR,J,K)/1000)))

Where:

CSHARE = Census to NERC regional Map

IRG = NERC Region

I = Census Division

GRIDSHR = Share of Total Sold to Utilities

CGCOMGEN = Commercial Cogeneration — Energy

CGCOMCAP = Commercial Cogeneration — Capacity

K = Vintage (Existing/Planned or Unplanned)

Commercial Revenues

LOCRCC = LOCRCC + (EWGAVP * TOTGENC) + (CGCOMPF * TOTCAPC)

EWGRCC = EWGRCC + LOCRCC

Where:

CGCOMPF = Commercial Cogen Fixed Cost

Calculate Industrial and Other Nonutility Revenues

Calculate Industrial and Other, Generation and Capacity Sold to Utilities

Generation:

TOTGENI = TOTGENI + (UQFGENN(IFL,IRG,4))

Capacity:

TOTCAPI = TOTCAPI + (ISHARE(IRG,K)*(CGINDCAP(K,IYR,I,1,L)/1000))

Add Non-traditional cogen to capacity charges

TOTGENI = TOTGENI + (ECSCAP(IDSP,IVIN,4)/1000)

Revenues

LOCRIC = LOCRIC + (EWGAVP * TOTGENI) + (CGINDPF * TOTCAPI)

Where:

ISHARE = Census to NERC region map

UQFGENN = Industrial Cogeneration (Energy)

K = Census Division

IYR = Model Year

I = Fuel Type

CGOTGEN = Generation at Other Cogen Facilities (i.e., not industrial or commercial)

CGINDCAP = Industrial Cogen Capacity

L = Vintage (Existing/Planned or Unplanned)

CGOTCAP = Other Cogen Capacity (i.e., not industrial or commercial)

CGINDPF = Industrial Fixed Component Price

CGOTPV = Other Cogen Variable Component Price

CGOTPF = Other Cogen Fixed Component Price

Calculate Revenues from International Electricity Trade

ETIMPD = (EWGAVP*ETIMPE)

ETEXPD = (EWGAVP*ETEXPE)

Where:

ETIMPE = International Economy Imports (MWh)

ETEXPE = International Economy Exports (MWh)

Subroutine: ELSO2N

Description:	This subroutine accumulates SO2 emissions and allowances across regions for each compliance group.
Called by:	ELEFD
Source:	uefd.f
Includes:	parametr, emmparm, control, dispin, dispout, uso2grp
Calls:	—
Equations:	None

Subroutine: EMMFUEL

Description:	This subroutine checks fuel supply convergence and revises fuel prices.
Called by:	ELEFD
Source:	uefd.f
Includes:	parametr, ncntrl, emmparm, control, fuelin, dispuse
Calls:	—
Equations:	None.

Subroutine: ELSO2F

Description:	This subroutine assigns penalty cost to regional arrays.
Called by:	ELEFD
Source:	uefd.f
Includes:	parametr, emmparm, dispin, dispout, uso2grp
Calls:	—
Equations:	None

Subroutine: GETOUT

Description:	This subroutine opens the direct access file OUTDAF.
Called by:	ELEFD, RETREDN, ELRPSCR
Source Code:	udaf.f
Includes:	parametr, emmparm, control, dispout
Calls:	—

Equations: None.

Subroutine: STRSO2

Description: This subroutine saves information temporarily stored in the common block USO2GRP in
                 a file, in particular, the total SO$_2$ produced, the penalty cost, and the SO$_2$ allowances.

Called by: ELEFD

Source: udaf.f

Includes: parametr, emmparm, control, uso2grp

Calls: —

Equations: None

Subroutine: ELRPSCR

Description: This subroutine does the renewable credit trading. Each fuel plant type that is included
                 (studies vary as to what kinds of fuels are included) in the renewable portfolio standard
                 is accounted for here. Credits are based on the percentage of renewable generation to
                 total generation.

Called by: ELEFD

Source: uefd.f

Includes: parametr, emmparm, control, dispin, dispuse, dispout, uefdout, udatout, ecpcntl, bildin,
                 bildout, cogen, eusprc, efpint

Calls: GETIN, GETOUT, STROUT

Equations: None

Subroutine: EFDBASE

Description: This subroutine saves information from EFD inputs and outputs for writing to EMM
                 database. The EFD includes information on plants, dispatching, trade, and generation.

Called by: ELEFD

Source: util.f

Includes: parametr, emmparm, control, dispin, dispout, dispett, ncntrl, plntctl, eusprc, edbdef,
                 uso2grp

Calls: —

Equations: None

Subroutine: DSMEFD

Description: This subroutine was modified to calculate the demand cumulants from the system load
                 duration curve. Yearly system load is described by 864 load allocation factors, each
                 representing load during a particular few hours of the year. From these load allocation
                 factors, the load in each of 108 slices (six seasons with 18 slices per season) is
                 determined. The corresponding demand cumulant for each slice is calculated using the
                 load allocation factors.

Called by: ELLDSM

Calls: None

Equations: Each load allocation factor is assumed to have a normal distribution with standard
                 deviation loadu. We approximate this through a discretization of the normal distribution,
                 which is used as a weighting for each point.

$$dval = (1. + dincr(iprob) * loadu) * (SYLOAD2(h))$$

                 where:

dincr = discretized value of the standard normal distribution at iprob standard deviations from the mean,

loadu = load standard deviation,

SYLOAD2(h) = system load at point h, and

dval = system load at weighting iprob.

Next we create moments around 0 at each point dval

$$dmomh(iprob,1)=dval*dprob(iprob)$$
$$dmomh(iprob,2)=dval^2*dprob(iprob)$$
$$dmomh(iprob,3)=dval^3*dprob(iprob)$$
$$dmomh(iprob,4)=dval^4*dprob(iprob)$$

where:

dmomh(iprob,imom) = moment imom for system load dval, and

dprob(iprob) = weight of segment iprob of the discretized normal distribution.

We add the contribution of each load allocation factor to the moments for the load slice and normalize by the hours in the slice

$$dmom(blk,imom)=dmom(blk,imom)+\frac{dmomh(iprob,imom)}{efdblWidth(blk)}$$

where:

dmom(blk,imom) = moment imom of EFD slice blk

efdblWidth(blk) = width (hours) of slice blk.

Finally we create the cumulants for this slice

$$dcum(iblk,1,RNB)=dmom(i,1)$$
$$dcum(iblk,2,RNB)=dmom(i,2)-dmom(i,1)^2$$
$$dcum(iblk,3,RNB)=dmom(i,3)-3*dmom(i,1)*dmom(i,2)+2.*dmom(i,1)^3$$
$$dcum(iblk,4,RNB)=dmom(i,4)-4.*dmom(i,1)*dmom(i,3)+6.*(dmom(i,1)^2*dmom(i,2))$$
$$-3.*dmom(i,1)^4-3*dcum(iblk,2,RNB)^2$$

where:

dcum(iblk,imom,RNB) = demand cumulant imom for slice iblk and region RNB.

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Appendix IV.A. Summary of Title IV
to the Clean Air Act Amendments of 1990

Unlike the previous New Source Performance Standards (NSPS) and Revised New Source Performance Standards (RNSPS) programs which set plant and unit specific emission rate limits, the CAAA program employs a unique, market-based approach to SO_2 emission reductions, while relying on more traditional methods for NO_x reductions. Under the market-based approach, utilities receive a limited number of marketable emission permits or "allowances" each year.[62] Each allowance permits the emission of 1 ton of SO_2 for that year or any year thereafter. In the EMM-NEMS these SO_2 allowances are treated as emission constraints on utility and nonutility planning and operations.

The acid deposition provisions of the CAAA are instituted in two phases. In Phase I, 1995 through 1999, allowances are allocated to large, electric-utility steam generating units fired by fossil fuels in an effort to limit their average SO_2 emissions to 2.5 pounds per million Btu of heat input.[63] No additional control is required at other units.

In Phase II, beginning in 2000, "basic" allowances are allocated to all electric-utility steam units greater than 25 megawatts in existence between 1985 and 1995.[64] New utility and nonutility units that begin operating after 1995 are required to have allowances beginning in 2000, which they must acquire through the market or in some other manner. In general, the amount of allowances allocated to a particular unit is determined by its size, primary fuel, 1985 emission rate, average fuel consumption from 1985 through 1987, and the year it began operation. The annual "basic" allowance allocation is limited to 8.95 million tons. In addition, almost 0.5 million "bonus" allowances are distributed each year for the first 10 years of Phase II.

In both phases, 2.8 percent of the "basic" allowances intended to be allocated each year will be placed in a special reserve, a portion of which may be sold directly, the remainder to be auctioned. The auction is intended to stimulate the market and to give new entrants, such as independent power producers, access to allowances. The direct sale is intended to be a market of last resort for anyone needing but unable to acquire allowances. Proceeds from both the auction and the direct sale are returned to the original owners of the allowances. These auctions and direct sales of allowances are not explicitly represented in the EMM-NEMS because of their small impact on the allowance market. However, they are included in the original allocation of allowances, and, thus captured in trading.

The CAAA establishes incentives (e.g., extra allowances and compliance-deadline extensions) for installing scrubbers during Phase I, instituting energy conservation, using new renewable energy sources, and using clean coal technologies. Presently the Environmental Protection Agency is finalizing procedures for a utility to take advantage of these incentives. When these procedures are finalized the EMM-NEMS allowance constraints will be modified to reflect the distribution of these incentive allowances.

Allowances can also be banked (saved) for future use. Because fewer emissions are allowed after 1999, allowances will increase in value beginning in 2000. A utility may find it advantageous to overcomply from 1995 through 1999, saving allowances for use in Phase II. Because banking decisions are

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[62]Electricity generators must still meet the emission standards in existence before the passage of the CAAA.

[63]Phase I affects electric utility steam generating units with a nameplate capacity of 100 megawatts or greater and an actual 1985 SO_2 emission rate of 2.5 pounds per million Btu or greater. The names of the units and their Phase I allowances are listed in the CAAA.

[64]Units less than or equal to 25 megawatts, combustion turbines, solar units, wind turbines, geothermal units, and hydroelectric units are not subject to the requirements of the CAAA.

dependent on unit and utility specific information (including each utility's assumptions about future allowance costs), banking algorithms is not endogenized within EMM-NEMS. Analysis will be done exogenous to the model to access the economics of banking and the EMM-NEMS allowances constraints will be adjusted to reflect the estimated levels of banking in future versions of NEMS.

Utilities must also submit compliance plans for and install continuous emission-monitoring devices at all affected units. A utility that does not comply (emits SO_2 in excess of the allowances it holds) must pay $2,000 for each ton of SO_2 it emits in excess of its allowances and must offset those emissions the following year.

The CAAA also requires the Environmental Protection Agency (EPA) to set new NO_x emission standards for existing and new utility boilers. For existing tangentially-fired boilers[65] the maximum emission rate the EPA can set is 0.45 pounds of NO_x per million Btu of heat input; for existing dry-bottom wall-fired boilers[66] (excluding cell-burner technology[67]) the maximum is 0.50 pounds per million Btu. These new standards must be met by 1995. For cyclones,[68] wet-bottom wall-fired boilers,[69] cell-burner technology, and other utility boilers, the EPA has until 1997 to set new standards, taking into account available technology and environmental considerations. In addition, by 1993, the EPA must revise the performance standards for NO_x emissions from new units to account for improved emission-reduction methods since the 1979 revision.

The SO_2 emission allowance program established in the CAAA offer a more economical approach to emissions control compared with the NSPS and RNSPS programs established in the original Clean Air Act and its earlier amendments. By establishing a market for emission permits, utilities with relatively high cost emissions reduction options will be able to purchase allowances from other utilities with lower cost options. These allowance trades among utilities are expected to continue until there are no gains or savings to be made, resulting in the most cost-effective solution.

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[65]Tangentially-fired boilers are fired from the corners of the furnace; the fireball can be directed upward or downward.

[66]Wall-fired boilers have burners mounted on their front and back walls. Dry-bottom wall-fired boilers use coal with high ash-fusion temperatures. Most of the fly ash is removed just ahead of the stack.

[67]Cell-burner technology is used in dry-bottom wall-fired boilers. The burners are arranged in clusters on the firing wall to reduce NO_x emissions.

[68]In a cyclone boiler, combustion occurs in water-cooled horizontal cylinders connected to the furnace walls. High-velocity air is fed tangentially to the cylinders, and the combustion gases exit into the furnace.

[69]Wet-bottom wall-fired boilers use coal with low-ash fusion temperatures, where the slag tends to cling to the walls and bottom of the furnace. In a wet-bottom furnace, the slag drops into a tank of water.

V. 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,[70] and financial ratios for each stage of production (generation, transmission and distribution.)

Electricity 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,[71] are determined in separate submodules of the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS) and transferred to the EFP as expense items.

There are three exceptions to the use of traditional rate of return regulation for determining revenue requirements in the EFP. These exceptions are sales-leaseback transactions,[72] phase-in plans for new generating units,[73] and disallowances.[74] These exceptions are 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.[75] The model solves for internal cash flow and determines the need for external financing in order to meet capital expenditures.

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[70]Revenue requirements are the costs that a ratemaking authority allows a regulated utility to recover from ratepayers.

[71]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).

[72]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.

[73]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.

[74]A disallowance occurs when a ratemaking authority refuses to allow a utility to recover the costs of building a plant or a portion of a plant through the rates it charges consumers. Grounds for a disallowance could be that the utility has built more generating capacity than it needs, or the ratemaking authority judges that the utility's management was imprudent in some aspect of the manner in which the building project was undertaken.

[75]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.

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.[76] 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.

Alternative regulatory and financial treatments that can be simulated in the EFP are flow-through versus normalized accounting,[77] construction work in progress (CWIP) versus allowance for funds used during construction (AFUDC),[78] 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.

The EFP can be used as a quantitative tool to examine a wide variety of policy issues and options. The following are some of the types of studies in which the EFP's predecessor, the National Financial Statements model (NUFS), has been used in the past to analyze impacts on electricity prices and electric utility financial performance:

- Allowing alternative levels of CWIP in rate base

- Examining the impacts of Federal income tax reform proposals

- Recovering costs associated with canceled nuclear plants

- Analyzing price impacts of proposed acid rain legislation

- Analyzing alternative regulatory or financial environments such as normalization versus flow-through accounting, changes in interest rates or allowed rates of return, and varying regulatory lag

- Analyzing alternative rates of future electricity demand growth

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[76]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.

[77]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.

[78]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.

- Examining financial feasibility of least-cost optimal capacity expansion plans

- Implementing alternative capacity expansion plans under different assumptions of cost escalation.

Relationship to Other Models

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 V.1). 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 Load and Demand Side Management (LDSM) 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.[79]
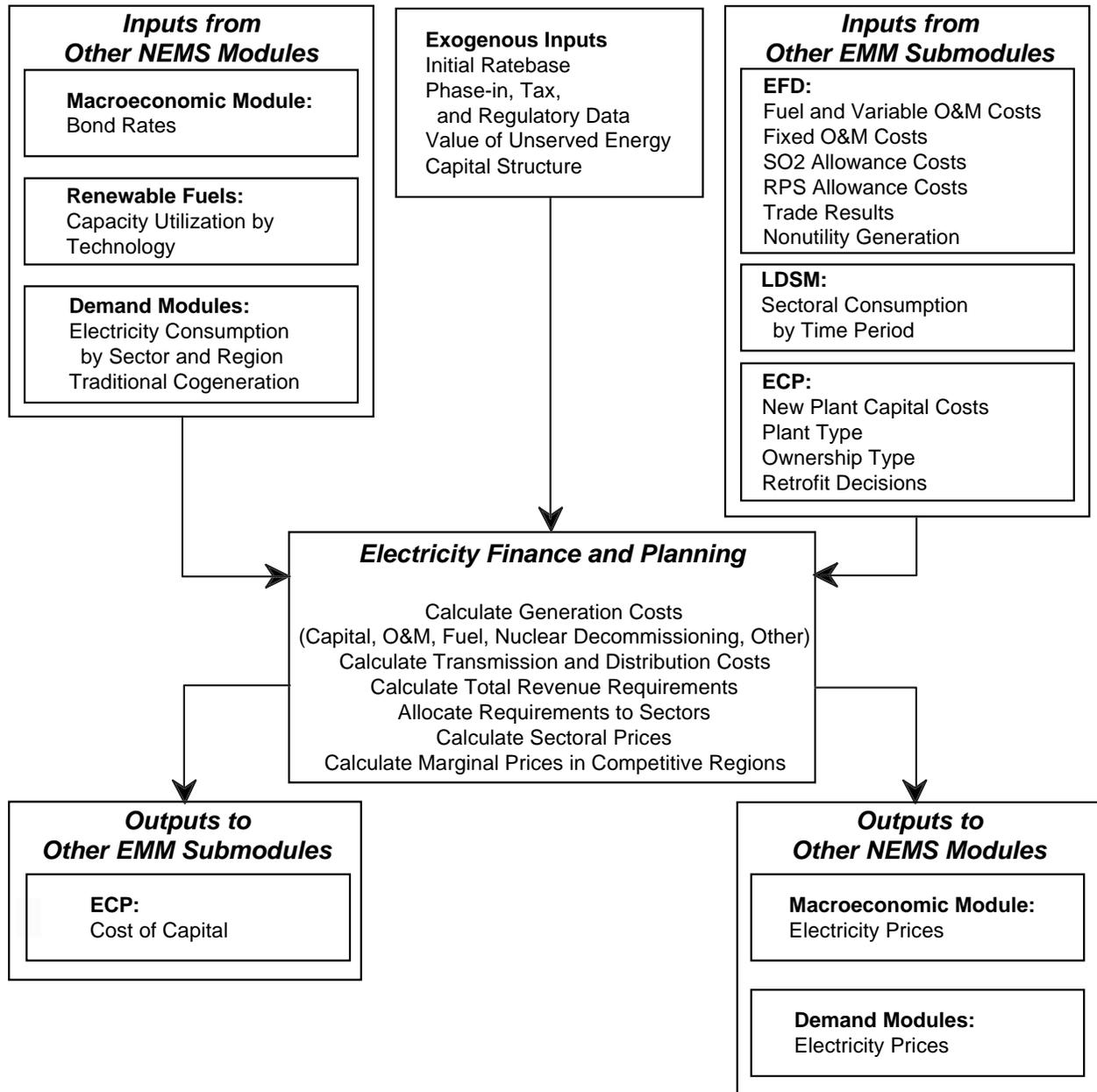
The amount of power purchased from industrial and commercial cogeneration facilities and refineries (kilowatthours) and the amount paid by utilities is passed from the Electricity Fuel Dispatch (EFD) submodule. The EFP includes this information in its average revenue calculations.

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.

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[79]In order to calculate average revenues the EFP will calculate revenue requirements and divide the result by total sales in kilowatthours.

Figure V.1. Input/Output Flows for the Electricity Finance and Pricing Submodule

Inputs from Other NEMS Modules	Exogenous Inputs	Inputs from Other EMM Submodules
Macroeconomic Module: Bond Rates	Initial Ratebase Phase-in, Tax, and Regulatory Data Value of Unserved Energy Capital Structure	**EFD:** Fuel and Variable O&M Costs Fixed O&M Costs SO2 Allowance Costs RPS Allowance Costs Trade Results Nonutility Generation
Renewable Fuels: Capacity Utilization by Technology		**LDSM:** Sectoral Consumption by Time Period
Demand Modules: Electricity Consumption by Sector and Region Traditional Cogeneration		**ECP:** New Plant Capital Costs Plant Type Ownership Type Retrofit Decisions

Electricity Finance and Planning

Calculate Generation Costs
(Capital, O&M, Fuel, Nuclear Decommissioning, Other)
Calculate Transmission and Distribution Costs
Calculate Total Revenue Requirements
Allocate Requirements to Sectors
Calculate Sectoral Prices
Calculate Marginal Prices in Competitive Regions

Outputs to Other EMM Submodules	Outputs to Other NEMS Modules
ECP: Cost of Capital	**Macroeconomic Module:** Electricity Prices
	Demand Modules: Electricity Prices

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,
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.

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.

The first step in calculating generation and transmission transfer 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 generation capacity expansion. Additions to the distribution ratebase are determined in the EFP as a function of sales. 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, emission 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.[80]

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 Load and Demand Side Management — LDSM — 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

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[80]The system, or coincident 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.

load to the sum of the individual peak loads. This method will be used most frequently to allocate distribution fixed O&M and capital costs, and will be used with the average and excess demand using probability of contribution to peak (AED-PCP) method (discussed below) to allocate transmission fixed O&M and capital costs.

Average and excess demand method using the probability of contribution to peak (AED-PCP) or coincident peak (AED-CP). This cost allocation method recognizes that capital additions are not made solely for peak demands. Sometimes capital additions are needed for fuel cost savings or other sales oriented reasons. Customer class peaks and system load factors are both used in allocating costs. In this method costs are first divided into those that will be allocated on the basis of average demand and those that will be allocated on the basis of "excess" or peak load demand. Those costs to be allocated on the basis of average demand are allocated first. 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:

$$\text{Average Revenue}_{ij} = \text{Total Revenue}_{ij} / \text{Sales}_{ij}$$

where:

$\text{Average Revenue}_{ij} =$ average revenue (retail price) of electricity for customer class i and region j

$\text{Total Revenue}_{ij}$ = revenue requirement allocated to customer class i and region j

Sales_{ij} = sales to customer class i and region j.

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 so as 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.[81] 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 information from each of the planning years of the solution derived in the Electricity Capacity Planning Module 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 could occur in the next decade: (1) industry structural changes, and (2) capital investment changes.

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[81]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).

Changes Related to Industry Structure

The structure of the electric power industry today, in which vertically integrated franchise monopolies[82] 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 may be breaking down as a result of policy initiatives such as reform of the PUHCA and efforts to increase competition in the power generation arena to increase efficiency by encouraging the emergence of nonutility generators. In many cases, wholesale rates for nonutility generators are set by means other than the traditional cost of service approach. Competitive bidding and other mechanisms that produce market based rates[83] are currently being used by regulated utilities to select nonutilities (NUGs) as suppliers of wholesale power.

As a result of this potential disintegration,[84] separate companies working within distinct regulatory frameworks could be involved in each of the three primary stages of production of the industry: generation, transmission, and distribution.[85] Therefore these three stages of production 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 will facilitate an analysis of industry structural change, allow for independent assumptions for each of the three stages of production with regard to regulatory and tax treatment, and will allow 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 of these stages 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. An assumption of the EFP is that retail electricity rates will continue to be regulated on a cost of service basis. 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 Load and Demand Side Management submodule (LDSM) 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.

Changes Related to Capital Expenditures

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[82]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.

[83]The term, market based rates, is a general term here that refers to prices established in whole or part by market transactions. Examples include competitive bidding by IPP's to build and operate generating capacity and price caps set by the Federal Energy Regulatory Commission (FERC) for wholesale electricity rates.

[84]Vertical disintegration and unbundling are synonymous terms.

[85]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.

The second broad based change has to do with investment emphasis. In the 1970's and 1980's, most capital expenditures were for construction projects. However, over the next ten years, a sizable amount of capital expenditures will be 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.

Cost and performance information for DSM programs will be developed in the Load and Demand-Side Management Submodule of the EMM in NEMS while their penetration and impacts will be represented in the individual demand models. The EFP accounts for these direct costs, whether expensed or capitalized, and includes them in the pricing function. In the electric power industry, it is necessary to compensate utilities for the reduction in revenues that results from DSM programs through revenue adjustment mechanisms because the rates that they charge are based on historic test periods that reflect a higher demand for electricity. Lost revenues (and profits) which can result from utility investments in DSM programs are captured in the EFP because it calculates average revenues (prices) based on demand after adjustment for DSM impacts. The EFP is also able to capture the adjustments to allowed rates of return that some states are offering to utilities as incentives for implementing DSM programs through adjustments to the model's return on equity component of average revenues.

Solution Algorithm and Key Computations

Overview

The purpose of this section is to describe the solution algorithm used within EFP. The discussion is organized into two parts. *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. With all of these items forecast, one has nearly all the necessary components to forecast the financial statements and ratios. The second part, *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.

Forecasting Revenue Requirements

The EFP method of forecasting revenue requirements duplicates 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:

$$ERRVRQ = (ERRB \cdot ESRR) + ERTFLN + ERTOMN + ERBDE + GENREG$$
$$+ STAREG + FEDREG - EROFFS + ESLLPN - EPIND$$

where:[86]

ERRVRQ	=	revenue requirement[87]
ERRB	=	rate base
ESRR	=	rate of return
ERTFLN	=	fuel costs
ERTOMN	=	operation and maintenance expenses, excluding fuel costs
ERBDE	=	book depreciation expense
GENREG	=	general taxes (gross receipts, property, sales) for regulatory purposes
STAREG	=	State income taxes for regulatory purposes
FEDREG	=	Federal income taxes for regulatory purposes
EROFFS	=	AFUDC offset
ESLLPN	=	net lease payment associated with sales/leaseback transactions
EPIND	=	net deferred phase-in revenues for year.

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 are needed to fully describe the solution

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[86]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.

[87]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.

algorithms. To aid in the continuity of this presentation, these discussions are also separated into their own sections. The discussions in the first set of sections sometimes refer to the later sections.

Calculation of Rate Base (ERRB):

The formula used to calculate the rate base is:

$$ERRB = ERTUP + ERRCWP + ERWC + ERNFSN - ERABDE - ERPRDF - (ERCNBV - ERCNAD) - ESLNDG - EDISNT$$

where:

ERRB = rate base

ERTUP = total utility plant

ERRCWP = 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.

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:

$$ERRBAQ = (ERRB + ERRBB)/2.0$$

$$ERRBB = ERRB_{t-1} + ERDLRB$$

where:

ERRBA = average year rate base

ERRB = end of year rate base

ERRBB = beginning year rate base

$ERRB_{t-1}$ = 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 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.

The values of ERCNBV and ERCNAD are calculated by summing the costs of all canceled projects. For projects canceled before the first year of the forecast horizon, the costs are specified by the analyst through inputs. For projects canceled after the first year of the forecast horizon, the analyst specifies which projects are to be canceled and at what point in time, and the costs of the projects are based on costs incurred up to the cancellation date (as simulated within the model).

ERRCWP, ERABDE, ERPRDF, ESLNDG, and EDISNT are discussed below.

Total Utility Plant (ERTUP):

Total Utility Plant (ERTUP) is calculated as:

$$ERTUP = \sum_{all\ k} (EOBKVL_k) + \sum_{all\ k} (ERBVYE_k) - ERBTIR$$

where:

$EOBKVL_k$ = 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. The calculation of ERBTIR is discussed below. $ERBVYE_k$ is calculated by summing the book values of each individual new asset of type k which is completed as of the year of forecast. The calculation of the book value of individual new assets is also discussed below.

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:

$$ERWC = 0.125 \cdot (ERTOMN + ERTFLN)$$

where:

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.

$$ERNFSN = 3.5 \cdot EFPNUC \cdot ESGNPD$$

where:

ERNFSN = Nuclear fuel stock

EFPNUC = Real dollar nuclear fuel expense

ESGNPD = inflation index to convert real dollars to nominal dollars

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:

$$ESRR = ESPRLT \cdot ESEMDT + ESPRST \cdot ESRTST + ESPRCE \cdot ESRTCE + ESPRPS \cdot ESEMPS$$

where:

ESPRLT = fraction of capital structure made up by long term debt

ESPRST = fraction of capital structure made up by short term debt

ESPRCE = fraction of capital structure made up by common equity

ESPRPS = fraction of capital structure made up by preferred stock

ESEMDT = embedded cost of long term debt

ESRTST = cost of short term debt

ESRTCE = allowed return on common equity

ESEMPT = embedded cost of preferred stock.

With the exception of ESEMDT, ESEMPT, and ESRTCE 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:

$$ESEMDT = \frac{(ESEMDL \cdot ERBNDL - ESEMDB \cdot RETIRE + ESRTLT \cdot (ERBOND - ERBNDL + RETIRE))}{ERBOND}$$

where:

ERBOND = ERAMD * ESPRLT

RETIRE = maximum of: ESPRLT * ERBDE; and EROBL

EROBE = EROBL - RETIRE

ESRTLT = UTBRRG1 + (UTBRRG2 * MC_RMPUAANS)

ERBOND = total long-term debt outstanding in current year

ERBNDL = total long-term debit outstanding from previous year

EROB = long-term debt outstanding in current year that was issued before the first year of the forecast period

EROBL = long-term debt outstanding in previous year that was issued before the first year of the forecast period

RETIRE = amount of debt that is retired in current year

ESRTLT   =   cost of new long-term debt issued

ERAMD   =   assets minus deferrals (i.e., amount that must be financed)

ESPRLT   =   fraction of capital structure made up by long-term debt

ERBDE =   book depreciation expense

ESEMDL   =   embedded cost of long-term debt in previous year

ESEMDB   =   embedded cost of long-term debt in the year previous to the first forecast year.

MC_RMPUAANS   =   the cost of new AA rated utility bonds

UTBRRG   =   regression coefficients

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. EROBL for a given year is equal to EROB from the previous year. ESRTNB, ESEMDB, EROBL (for first forecast year), and ESPRLT are user inputs in this algorithm. ERAMD and ERBDE are discussed below.

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.

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.

$$ESEMPS \ = \ \frac{(ESEMPL \cdot ERPRFL - ESEMPB \cdot RETIRE + ESRTPS \cdot (ERPREF - ERPRFL + RETIRE))}{ERPREF}$$

Where:

ERPREF   =   ERAMD * ESPRPS

RETIRE   =   maximum of: ESPRPS * ERBDE; AND ERPFL

ERPF   =   ERPFL - RETIRE

ESRTPS   =   PSRCF1 + (PSRCF2 * ESRTDA)

ERPREF   =   total preferred stock in current year

ERPRFL   =   total preferred stock from previous year

ERAMD   =   assets minus deferrals

ESPRPS   =   fraction of capital structure made up by preferred stock (user input)

RETIRE   =   amount of preferred stock that is retired in current year

ERBDE =   book depreciation expense

ERPF   =   preferred stock outstanding in current year that was issued before the first year of the forecast period

ERPFL   =   preferred stock outstanding in previous year that was issued before the first year of the forecast period

ESRTDA   =   the average cost of new long term debt

ESRTPS   =   cost of new preferred stock issued

ESEMPL   =   embedded cost of preferred stock from previous year

ESEMPB   =   embedded cost of preferred stock from the year previous to the first forecast year

PSRCF   =   regression coefficients

ERPFL for a given year is equal to ERPF from the previous year. 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.

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,[88] 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.[89] 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:

$$R_E = R_F + \beta(R_M - R_F)$$

where:

R_E   =   the required return on the company's common stock

R_E =   the required return on the company's common stock
R_F =   the risk-free rate of return (generally the return on 90-day Treasury bills)
β =   the beta coefficient
R_M =   the return on the market.

For the purposes of 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.[90] The return on the market is also an exogenous input.[91] 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

Fuel Costs (ERTFLN):

Fuel costs in each forecast year are derived from the results of the dispatch exercise.

$$ERTFLN = (EFPFL + BLKSUM) \cdot ESGNPD$$

where:
ERTFLN   =   nominal dollar fuel cost

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[88]For a detailed description of CAPM, see Energy Information Administration, *Investor Perceptions of Nuclear Power*, DOE/EIA-0446 (Washington, DC, May 1984).

[89]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.

[90]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.

[91]It is beyond the scope of NEMS to forecast a return on the stock market.

EFPFL	=	real dollar fuel costs as determined by the dispatch model plus emission costs
BLKSUM	=	real dollar wholesale purchase costs (includes imports, exports, purchases from NUGs and inter-regional transfers) 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:

$$ERTOMN = (ERTOM + OVERPR + ERTOMF + OMLE) \cdot ESGNPD$$

where:

ERTOM	=	real dollar production related variable operation and maintenance expenses
ESGNPD	=	inflation index to convert real dollars to nominal dollars.
ERTOMF	=	real dollar production related fixed O & M expenses
OVERPR	=	real dollar production and maintenance expenses allocated to the production function (e.g., general and administrative)
OMLE	=	real dollar O & M expenses associated with the life extension of the generating units

Transmission O&M:

$$ERTOMN = (ERTOMT + OVERTR) \cdot ESGNPD$$

where:

ERTOMT	=	real dollar transmission operation and maintenance expenses
ESGNPD	=	inflation index to convert real dollars to nominal dollars.
OVERTR	=	real dollar overhead-related O & M expenses allocated to transmission (e.g., general administration).

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.

$$ERTOMN = (ERTOMD + OVERDS) \cdot ESGNPD$$

where:

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 (ERBDE):

Discussion of the book depreciation expense is provided below.

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.

$$GENREG = EGTXRT \cdot ERRVRQ + ERPRTX + ERSLTX$$

where:

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). 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:

$$STAREG = (ERRVRQ - ERTFLN - ERTOMN - ERTDWO - ERTIEX - ESLLP) \cdot ESSTXR$$

where:

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.

$$ERSIEX = ESRTST \cdot ESPRST \cdot \frac{(ERAMD + ERAMDL - ESLPRC)}{2}$$

$$ERLIEX = ESEMDT \cdot ESPRLT \cdot \frac{(ERAMD + ERAMDL - ESLPRC)}{2}$$

$$ERTIEX = ERSIEX + ERLIEX$$

where:

ERSIEX	=	short-term interest expense
ERLIEX	=	long-term interest expense
ERTIEX	=	total interest expense
ESRTST	=	cost of short-term debt
ESEMDT	=	embedded cost of long-term debt

ESPRST	=	fraction of capital structure made up by short-term debt
ESPRLT	=	fraction of capital structure made up by long-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

ESRTST, ESPRST, and ESPRLT are user inputs. ESEMDT is discussed above. ERAMDL for a given year is equal to ERAMD from the previous year. ERAMD and ESLPRC are discussed below.

Assets Minus Deferrals (ERAMD):

ERAMD is the amount that must be financed by debt or equity.

$$ERAMD = ERTUP + ERBCWP + ERWC + ERNFSN + EPIDEF$$
$$- ERABDE - ERPRDF - ERDITC - EDISNT - ESLNDG$$

where:

ERTUP	=	total utility plant (see 1.1-a)
ERBCWP	=	booked construction work in progress (see 1.13)
ERWC	=	working capital (see 1.1-b)
ERNFSN	=	nuclear fuel stock (see 1.1-c)
EPIDEF	=	cumulative deferred phase-in revenues (see 1.17)
ERABDE	=	accumulated book depreciation (see 1.14)
ERPRDF	=	provision for deferred income taxes (see 1.14)
ERDITC	=	deferred investment tax credits (see 1.14)
EDISNT	=	net disallowed plant (see 1.17)
ESLNDG	=	net deferred gain from sale/leaseback transactions (see 1.16)

Federal Income Taxes for Regulatory Purposes (FEDREG):

FEDREG is equal to Federal taxable income (for regulatory purposes) multiplied by the Federal income tax rate, adjusted by several accounts reflecting timing differences between actual income taxes paid and regulatory income taxes:

$$FEDREG = (ERRVRQ - ERTFLN - ERTOMN - GENREG - STAREG - ERTDRG - ERTIEX + ERCIDC - ESLLP)$$
$$\cdot ESFTXR - ERFITC - ERAITC - ERFFDC - ERAFDC - EREDTF$$

where:

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 ITC that is 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. 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.

AFUDC Offset (EROFFS):

See "CWIPS," below.

Net Lease Payments Associated with Sale/Leaseback Transactions (ESLLPN):

See "Sale/Leaseback Transactions," below.

Net Deferred Phase-in Revenues (EPIND):

See "Rate Phase-in Plans," below.

Resolution of ERRVRQ "Circular" Argument:

The following four equations have been presented:

(1) ERRVRQ = . . . + GENREG + STAREG + FEDREG
(2) GENREG = EGTXRT * ERRVRQ + . . .
(3) STAREG = (ERRVRQ - . . .) * ESSTXR
(4) FEDREG = (ERRVRQ - . . . - STAREG - GENREG) * ESFTXR

In the somewhat linear presentation above, these equations seem to present a circular argument. (ERRVRQ is a function of GENREG, STAREG, and FEDREG, but also the later variables depend on ERRVRQ.) This specification, of course, is not really a problem. 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 (2), (3), and (4) can be substituted into equation (1) to yield:

$$ERRVRQ = \ldots + ERRVRQ \cdot EGTXRT + (ERRVRQ - \ldots) \cdot ESSTXR$$
$$+ (ERRVRQ - \ldots - STAREG - GENREG) \cdot ESFTXR$$

Next, substituting equations (2) and (3) into the above equation and gathering like terms yields:

$$ERRVRQ = \ldots + ERRVRQ \cdot EGTXRT \cdot (1 - ESFTXR) + (ERRVRQ - \ldots)$$
$$\cdot ESSTXR \cdot (1 - ESFTXR) + (ERRVRQ - \ldots) \cdot ESFTXR$$

Next, moving all terms on the right hand side of the equation that contain the variable ERRVRQ to the left hand side yields:

$$ERRVRQ \cdot (1 - EFTXRT \cdot (1 - ESFTXR) - ESSTXR \cdot (1 - ESFTXR) - ESFTXR)$$
$$= \ldots + (- \ldots) \cdot ESSTXR \cdot (1 - ESFTXR) + (- \ldots) \cdot ESFTXR$$

Finally, dividing the equation on both sides by the constant on the left hand side yields:

$$ERRVRQ = \frac{\ldots + (- \ldots) \cdot ESSTXR \cdot (1 - ESFTXR) + (- \ldots) \cdot ESFTXR}{1 - EGTXRT \cdot (1 - ESFTXR) - ESSTXR \cdot (1 - ESFTXR) - ESFTXR}$$

This equation yields a unique value for ERRVRQ. This value can then be substituted back into equations (ii), (iii), and (iv) to yield values for the remaining variables.

Construction Work in Progress (CWIP):

For regulatory purposes, EFP is able to simulate three alternative treatments of construction work in progress: 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. 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 quite a few variables. These effects will now be discussed. All of the discussions will assume only one plant is being built. This is for ease in presentation only, and going to the "n" plant case presents no conceptual problems. For the presented algorithms, the following values are input to EFP:

Variable	Description	Source
EBPCAP	Capacity of build	Distribution Planning Model
EBPCST	Real dollar cost per unit of capacity (real dollars/capacity), not including any financing costs incurred during construction	Distribution Planning Model
EBSYR	Year plant comes on line	Distribution Planning Model
ESLCP	Length (in years) of construction period (including first year of operation)	User
$ESCPRF_j$	Direct (i.e., not including financing charges) construction expenditures (in real dollars) in year j as a fraction of total direct construction costs (in real dollars)	User

Variable	Description	Source
$ESGNPD_j$	Inflation escalation index used to convert real dollars to current year j dollars, expressed as the ratio of current year j dollars to real dollars	User
$CWPPER_j$	Percentage (expressed as a fraction) of CWIP allowed in rate base, year j	User
ESRBAF	0 Remainder of CWIP (i.e., 1.0 - CWPPER) not in rate base) 1 Remainder of CWIP is under AFUDC offset	User
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 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:

$$ESAFDC = TEMPD + TEMPE$$

where:

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.

$$ESWACD = TEMPD/ESAFDC$$

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 j, where j ranges from the first year of construction (i.e., EBSYR - ESLCP + 1) to the first year of operation (i.e., EBSYR).

$$EBYCWPsubj = EBPCAP \cdot EBPCST \cdot ESCPRFj \cdot ESGNPDj \cdot CAPESC_j$$
$$\text{for } j = (EBSYR - ESLCP + 1) \text{ to } EBSYR$$

Where:

EBYCWP$_j$ = nominal dollar direct construction expenditures, year j

EBPCAP = capacity of build

EBPCST = real dollar cost per unit of capacity

ESCPRF$_j$ = real dollar direct construction expenditures, in year j, as a fraction of total direct construction expenditures

ESGNPD$_j$ = inflation index to convert real dollars to current year j dollars

CAPESC$_j$ = escalation index to escalate construction costs over and above inflation

EBSRY = 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 j during the construction period. This 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:

$$EBRCWP_j = (EBBCWP_j + EBYCWP_j) \cdot [CWPPER_j + ESRBAF \cdot (1.0 - CWPPER_j)]$$

where:

EBRCWP$_j$ = CWIP allowed in rate base, year j

EBBCWP$_{j-1}$ = booked CWIP, year j-1

CWPPER$_j$ = percentage of CWIP allowed in rate base, year j

EBYCWP$_j$ = nominal dollar direct construction expenditures, year j

ESRBAF = 0 if no AFUDC offset, and 1 if AFUDC offset.

Booked AFUDC in year j is calculated as:

$$AFUDC_j = (EBBCWP_{j-1} + 0.5 \cdot EBYCWP_j) \cdot (1 - CWPPER_j) \cdot ESAFDC_j$$

where:

AFUDC$_j$ = booked AFUDC, year j

EBBCWP$_{j-1}$ = booked CWIP, year j-1

EBYCWP$_j$ = nominal dollar direct construction expenditures, year j

CWPPER$_j$ = percentage of CWIP allowed in rate base, year j

ESAFDC$_j$ = AFUDC rate, year j

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 j is calculated as:

$$EBBCWP_j = 0$$

for $j = EBSYR - ESLCP$ (i.e., year before construction begins)

$$= EBBCWP_{j-1} + EBYCWP_j + AFUDC_j$$

for $j = (EBSYR - ESLCP + 1)$ to $EBSYR$ (i.e., construction period)

where:

$EBBCWP_j$	=	booked CWIP, year j
$EBYCWP_j$	=	nominal dollar direct construction expenditures, year j
$AFUDC_j$	=	booked AFUDC, year j

The AFUDC offset is calculated as:

$$EROFFS_j = AFUDC_j \cdot ESRBAF$$

where:

$EROFFS_j$ =   AFUDC offset, year j.

The book value of the new plant when it comes on line is:

$$EBBKVL = EBBCWP_j$$

where:

j	=	EBSYR (the first year of operation)
EBBKVL	=	book value of new plant

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.

$$EBASVL_j = 0$$

for $j = EBSYR - ESLCP$ (i.e., year before construction begins)

$$= EBASVL_{j-1} + EBYCWP_j + AVDINT_j$$

for $j = (EBSYR - ESLCP + 1)$ to $EBSYR$ (i.e., construction period)

$$= EBASVL_{EBSYR}$$

for $j = EBSYR$ to $(EBSRY + ESBKLF)$ (i.e., during service life)

where:

EBASVL	=	tax basis, year j
$EBYCWP_j$	=	nominal dollar direct construction expenditures, year j
$AVDINT_j$	=	interest capitalized for tax basis (avoided interest), year j

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:

$$AVDINT_j = (EBASVL_{j-1} + 0.5 \cdot EBYCWP_j) \cdot ESRTNB_j$$

where:

AVDINT$_j$ =   interest capitalized for tax basis (avoided interest), year j

EBASVL$_{j-1}$= tax basis, year j-1

EBYCWP$_j$ =   nominal dollar direct construction expenditure, year j

ESRTNB$_j$ =   cost of new debt, year j.

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:

$$ERFDCD_j = ESWACD_j \cdot AFUDC_j$$
$$ERFDCE_j = (1 - ESWACD_j) \cdot AFUDC_j$$

where:

ERFDCD$_j$ =   debt financed portion of AFUDC, year j

ERFDCE$_j$ =   equity financed portion of AFUDC, year j

ESWACD$_j$ =   fraction of AFUDC representing debt costs, year j (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.

$$ERFFDC_j = ERFDCD_j \cdot ESFTXR \cdot ESFPDB$$
$$ERXFDC_j = ERFDCD_j \cdot ESFTXR \cdot (1 - ESFPDB)$$

$$DAFDC_j = \sum_{i=k}^{j} ERXFDC_i$$

for $j = K$ to $EBSYR$
where $K = EBSYR - ESLCP + 1$

where:

ERFFDC$_j$ =   generated tax savings from the debt portion of AFUDC that is flowed through, year j

ERFXFDC$_j$=   generated tax savings from the debt portion of AFUDC that is deferred (normalized), year j

DAFDC$_j$ =   deferred tax savings from the debt portion of AFUDC, year j

ERFDCD$_j$ =   debt-financed portion of AFUDC, year j, (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.

$$EBAFDC = DAFDC_{EBSYR}/ESBKLF$$

$$DAFDC_j = DAFDC_{j-1} - EBAFDC$$

for $j = EBSYR$ to $(EBSYR + ESBKLF - 1)$ (i.e., over service life of plant)

where:

EBAFDC = annual amortization of deferred savings from the debt portion of AFUDC

$DAFDC_j$ = deferred tax savings from the debt portion of AFUDC, year j

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:

$$ERCIDC_j = ERXFDC_j + AVDINT_j$$

where:

$ERCIDC_j$ = interest capitalized for the purposes of calculating Federal income taxes for regulatory purposes, year j

$ERXFDC_j$ = generated tax savings from the debt portion of AFUDC that is deferred, year j

$AVDINT_j$ = interest capitalized for tax basis, year j (see Step 4 above).

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.

The following discussion applies to a new plant with the following input characteristics:

EBSYR = year plant comes on line

ESBKLF = book life of plant

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):

$$ERBDE_j = (EBBKVL - EBABDE_{j-1})/(ESBKLF - (J - EBSYR))$$

and

$$EBABDE_j = \sum_{i=EBSYR}^{j} ERBDE_i$$

for $j = EBSYR$ to $EBSYR + ESBKLF - 1$ (i.e., over service life of asset)

where:

ERBDE$_j$ = book depreciation, year j

EBABDE$_j$ = accumulated book depreciation, year j

EBBKVL = book value of plant (includes any AFUDC).

The derivation of EBBKVL is discussed above. 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 this 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.[92]

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 determined 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.

$$ERTDE_j = EXTXRS_j \cdot (EBASVL - 0.5 \cdot EBDITC)$$

for $j = EBSYR$ to $EBSYR + ESBKLF - 1$ (i.e., during the service life of the plant)

where:

ERTDE$_j$= depreciation expense for tax purposes, year j

EBASVL = tax basis of asset

EXTXRS$_j$ = depreciation rate prescribed by ERTA or TRA, year j

EBDITC = investment tax credits generated.

EBASVL is discussed above. EBDITC is described below.

Absent accelerated depreciation, tax depreciation would be:

$$ERTDWO_j = ESDEPR \cdot (EBASVL - 0.5 \cdot EBDITC)$$

for $j = EBSYR$ to $EBSYR + ESBKLF - 1$ (i.e., during the service life of the plant)

where:

ERTDWO$_j$ = depreciation for tax purposes, without acceleration, year j

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[92]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.

ESDEPR = straight-line depreciation rate.

The difference between $ERTDWO_j$ and $ERTDE_j$ 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.

$$ERTDRG_j = ERTDWO_j \cdot (1 - ESFLPR) + ERTDE_j \cdot (ESFLPR)$$
$$\text{for } j = EBSYR \text{ to } EBSYR + ESBKLF - 1 \text{ (i.e., during the service life of the plant)}$$

where:

ERTDRG_j = tax depreciation expense for regulatory purposes, year j

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:

$$ERATSF_j = ESFTXR \cdot (ERTDE_j - ERTDWO_j) \cdot ESFLPR$$
$$ERATSD_j = ESFTXR \cdot (ERTDE_j - ERTDWO_j) \cdot (1 - ESFLPR)$$
$$DAD_j = \sum_{i=EBSYR}^{j} ERATSD_i \text{ for } j = EBSYR \text{ to } EBSYR + ESBKLF - 1$$

where:

ERATSF_j = tax savings resulting from accelerated depreciation that are flowed through, year j

ERATSD_j = tax savings resulting from accelerated depreciation that are deferred, year j

DAD_j = provision for deferred taxes due to accelerated tax depreciation, year j

ESFTXR = Federal income tax rate.

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.

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:

$$EXCESS = \sum_{j=EBSYR}^{IYREDT} (ERTDE_j - ERTDWO_j) \cdot (ESFTXR_j - ESFTXR_{IYREDT})$$

where:

EXCESS   =   total excess deferred income taxes

ERTDE =   depreciation expense for tax purposes, year j

ERTDWO   =   depreciation for tax purposes, without acceleration, year j

$ESFTXR_j$ =   Federal income tax rate, year j (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:

$$EREDTF_j = 0.0 \qquad \text{if } j < IYREDT$$
$$= EXCESS/REMLIF \qquad \text{if } j \geq IYREDT$$

where:

EREDTF   =   excess deferred taxes flowed back to ratepayers each year

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.

$$ERPRDF = DAD + DAFDC - EREDTF$$

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.

$$ERFITC_j = EBYCWP_j \cdot ESRITC_j \cdot ESFLPR$$
$$XITCD_j = EBYCWP_j \cdot ESRITC_j \cdot (1 - ESFLPR)$$

$$EBDITC_j = \sum_{i=K}^{j} XITCD_i \quad \text{for } j = K \text{ to } EBSYR, \text{ where } K = EBSYR - ESLCP + 1$$

where:

ERFITC$_j$ =   generated ITC that is flowed through, year j
XITCD$_j$ =   generated ITC that is deferred, year j
EBDITC$_j$ =   deferred ITC, year j
EBYCWP   =   construction expenses, net of AFUDC, year j (see 2.1.13-b)
ESRITC$_j$ =   investment tax credit rate, year j
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.

$$ERAITC = EBDITC_{EBSYR} / ESBKLF$$
$$EBDITC_j = EBDITC_{j-1} - ERAITC$$
$$\text{for } j = EBSYR \text{ to } EBSYR + ESBKLF - 1$$

where:

ERAITC   =   amortization of deferred investment tax credit
EBDITC$_j$ =   deferred ITC, year j,
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.

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:

$$SLBKVL = SLPROC - BKGAIN$$
$$SLGAIN = BKGAIN - SLTAXS$$
$$SLASVL = SLPROC - SLTAXS / ESFTXR$$

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:

$$ESLPRC = SLPROC - SLTAXS$$
$$ESLLP = SLLP$$
$$ESLAGN = SLGAIN / SLTERM$$
$$ESLNDG_j = SLGAIN - j \cdot ESLAGN \text{ for } j = 1, SLTERM$$
$$ESLLPN = ESLLP - ESLAGN$$

where:

ESLPRC	=	net of tax sales proceeds
ESLLP	=	annual lease payment
ESLAGN	=	amortization of gain
ESLNDG	=	net deferred gain from transaction
ESLLPN	=	net least 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.

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.

In recent years, however, many situations have arisen where, under traditional regulation, substantial rate increases would occur as new plants com eon line. This has been caused by two major forces. First, the costs of new power plants have risen substantially. This widely discussed phenomenon has caused the capital costs of the plant to be substantially higher. Second, at the same time, the savings derived from lower operating costs of the new plants have 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 has brought on line a new plant whose total costs make 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, forbids 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 has emerged and is referred to as rate phase-in plans.

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. In practice, each rate phase-in plan is at least somewhat unique in response to the particulars of the situation.

For the algorithm presented below, the following values are input for each rate phase-in plan to be modeled:

Variable	Description
IBYRPI	Year rate phase-in plan begins
PIBKVL	Book value of phase-in plant
DISPER	Fraction of phase-in plant disallowed
LIP	Length of phase-in plan
$PIDFS_j$	Cumulative fraction of total cost to be phase-in in year j
$PIRCS_j$	Fraction of remaining deferred revenues to be recovered in year j
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 the "n" 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:

$$RR_j = \frac{PIBKVL \cdot (1.0 - DISPER) \cdot (1.0 - j/PIBKLF) \cdot ESPR/(1.0 - ESFTXR) + PIBKVL}{PIBKLF \cdot (1.0 + (1.0 - PITXBS) \cdot ESFTXR/(1.0 - ESFTXR)))}$$

$$\text{for } j = 1, LPI$$

where:

RR_j = traditional revenue requirement of phase-in plant, year j
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:

$$EPIND_j = RR_j \cdot (1.0 - PICFS_j) \cdot (1.0 - ESFTXR) - PIRCSj \cdot EPIDEF_{j-1}$$
$$\text{for } j = 1, LPI$$

where:

$EPIND_j$ = pre-tax deferred costs, year j
RR_j = traditional revenue requirement of phase-in plant, year j
$PIDFS_j$ = cumulative fraction of total cost to be phased-in in year j (input)
ESFTXR = federal income tax rate (input)
$PIRCS_j$ = fraction of remaining deferred revenues to be recovered in year j (input)
$EPIDEF_{j-1}$ = cumulative deferred costs, year j-1 (see below).

Note that $EPIND_j$, 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):

$$EPIRET_j = (EPIDEF_{j-1} + 0.5 \cdot EPIND_j) \cdot ESAFDC$$
$$\text{for } j = 1, LPI$$

where:

$EPIRET_j$ = capitalized return on deferred costs, year j
$EPIDEF_{j-1}$ = cumulative deferred costs, year j-1 (see below)
$EPIND_j$ = pre-tax deferred costs, year j
ESAFDC = AFUDC rate

Next, cumulative deferred costs are calculated:

$$EPIDEF_j = EPIDEF_{j-1} + EPIND_j + EPIRET_j$$
$$\text{for } j = 1, \; LPI$$

where:

EPIDEF$_j$ =   cumulative deferred costs, year j

EPIND$_j$ =   pre-tax deferred costs, year j

EPIRET$_j$ =   capitalized return on deferred costs, year j

EPIDEF begins year 1 with a value of 0.0.

Finally, the net value of disallowed plant is calculated:

$$EDISNT_j = PIBKVL \cdot DISPER \cdot (1.0 - j/PIBKLF)$$
$$\text{for } j = 1, \; PIBKLF$$

where:

EDISNT$_j$ =   net disallowed plant, year j

PIBKVL =   book value of phase-in plant (input)

DISPER   =   fraction of phase-in plant disallowed (input)

PIBKLF =   book life of phase-in plant (input).

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:

$$Balance_y = Balance_{y-1} + Earnings_y - Tax_y - (Administrative\ Cost)_y + Payment_y$$

where the fund payment is calculated in one of two ways:

1. For years before the early retirement year (if applicable) and before the input "catch up" year, the payment is calculated as the input payment adjusted for inflation.

2. For all other years, the payment is calculated as the annuity payment necessary over the remaining period of collection (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.

Competitive Pricing Algorithm:

As proposed by W. Vickrey in 1971, spot or responsive pricing allows for economically optimal behavior by each customer and avoids system overload without having to resort to rationing because the price of electricity increases or decreases as system conditions change.[93] True spot prices are set and communicated by suppliers of electricity services (or other services) instantaneously. Different prices can be set for each customer location at each moment. Most State proposals for restructuring of the U.S. electric power industry are modeled after the spot market in the United Kingdom (UK). In the UK, spot prices for generating services are set a day in advance by an Independent System Operator (ISO), on the basis of competitive bids from generating plants.

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 maintenance (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.

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

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[93]R.E. Bohn, M.C. Caramanis, and F.C. Schweppe, "Optimal Pricing in Electrical Networks Over Space and Time," *Rand Journal of Economics* (Autumn 1984).

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 108 time periods used in the EFD submodule. 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.[94] 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.[95]

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).

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

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[94]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.

[95]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).

margins may fall. Lower reserve margins could have important implications for system operating costs and electricity prices.[96]

Mathematically, the reliability adjustment of price is represented as:

$$C_{ryt} = \left(\frac{\partial UE}{\partial G} \right)_{ryt} \cdot V(UE) \quad ,$$

where:

C_{ryt} =   reliability adjustment of price, year *y*, pricing period *t* for region *r* (cents per kilowatthour),

$\left(\dfrac{\partial UE}{\partial G} \right)_{ryt}$ =   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 . 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 was added to summarize the relationship between revenues and total costs for each region. Finally, subroutine RATES was modified to include the effects of AB1990 in California.

In summary, the spot price of electricity under competition is represented as:

$$Pcomp_{ryt} = E_{ryt} + C_{ryt} + Tax_{ryt} + TD_{ry} \quad ,$$

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),

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).

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[96]Energy Information Administration, *Annual Energy Outlook 1996*, DOE/EIA-0383(96) (Washington, DC, January 1996), p. 30.

Remaining Algorithms

Part 1 of this section described the EFP algorithms used to forecast the major components of revenue requirements. This section describes the remaining algorithms which are used to yield forecasts of electric revenues, the 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. 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:

$$ERRVLG = ERRVRQ$$

where:

ERRVLG   =   electric revenues

ERRVRQ   =   revenue requirements

In a 1-year lag scenario, electric revenues are calculated as follows:

$$ERRVLG_t = [(ERRB'_{t-1} \cdot ESRR_t) + ERTOMN_{t-1} + ERBDE_{t-1} + GENREG_{t-1} + STAREG_{t-1}$$
$$+ FEDREG_{t-1} - EROFFS_{t-1} + ESLLPN_{t-1} - EPIND_{t-1}] \cdot EQTLSL_t / EQTLSL_{t-1} + ERTFLN_t$$

where variables are same as in part 1 above, except:

ERRB'$_{t-1}$ =   ERRB$_{t-1}$ + (EBRCWP$_t$ - EBRCWP$_{t-1}$)

EQTLSL$_t$ =   total sales of electricity, year t.

This equation is similar to the equation for revenue requirements presented in part 1 above. However, the right-hand variables are lagged by 1 year, with some exceptions. First, the rate base used 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 an 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 ration 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 case are used in the other scenarios (e.g., one-half-year lag).

Forecast sales of electricity are passed to EFP from the dispatch module being used to drive EFP.

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 any of the following methods:

Sales Method:

Costs are allocated on the basis of the proportion of total sales to the class as follows:

$$DEMFAC1_j = SALCLS_j / SALTOT$$

where:

DEMFAC$_n$ =   the factor for allocating costs to customer class j
SALCLS   =   the total sales of electricity to class j
SALTOT   =   the total sales of electricity to all classes

Coincident Peak Method:

Costs are allocated on the basis of each customer class's contribution to the system peak load:

$$DEMFAC5_j = SECANNUALPEAK1_j / TOTAL$$

where:

SECANNUALPEAK1$_j$ =   the load attributable to customer class j at the time of the system peak
TOTAL   =   the total load on the system at the time of system peak

Probability of Contribution to Peak   :

Costs are allocated on the basis of the average contribution to system peak of the customer class over a number of previous model years:

$$DEMFAC6_j = SECANNPEAAVPCP_j / TOTAL$$

where:

SECANNPEAAVPCP$_j$ =   the average contribution 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:

$$DEMFAC7_j = SECANNUALPEAK2_j / TOTAL$$

where:

SECANNUALPEAK2$_j$ =   the load of customer class j at the time of the peak load of customer class j
TOTAL   =   the sum of the customer class loads at the time of the peak for each individual customer class (non-coincident peak)

Average and Excess Demand Using Coincident Peak:

Costs are allocated using a combination of the sales method (average demand) and the coincident peak (excess demand). The proportion of costs equal to the level of the system load factor is allocated on the basis of the sales method. The remaining costs are allocated on the basis of the coincident peak method:

$$DEMFAC8_j = (SYSTEMLF \cdot DEMFAC1) + [(1 - SYSTEMLF) \cdot DEMFAC5]$$

where:

SYSTEMLF = the system load factor

Average and Excess Demand Using Probability of Contribution to Peak:

This method is the same as that described above except that the proportion of costs in excess of the system load factor is allocated on the basis of the probability of contribution to peak instead of the coincident peak method:

$$DEMFAC9_j = (SYSTEMLF \cdot DEMFAC1) + [(1 - SYSTEMLF) \cdot DEMFAC6]$$

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:

$$COSTFC_{kjl} = \sum DEMFAC_{nj} \cdot TECFAC_{nkl}$$

where:

$COSTFC_{kjl}$ = the sum of all allocation proportions for cost type k, customer class j, and stage of production l

$DEMFAC_n$ $_j$= allocation proportion using method n for customer class j

$TECFAC_{kjl}$ = the proportion of cost type k to be allocated using method n for stage of production l

and revenues are allocated to the class:

$$REV_{jl} = COSTFC_{kjl} \cdot COST_{kl}$$

where:

REV_{jl} = 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:

Price Calculation:

$$EPRICE_{jl} = REV_{jl}/SALCLS_j$$

where:

$EPRICE_{jl}$ = the price of electricity for customer class j and stage of production l

REV$_{jl}$ = electric revenues allocated to customer

SALCLS = sales to customer

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 residential, commercial, and transportation are compared to historic prices for benchmarking and subsidy calculation.[97] 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:

$$REVHPCT_{jy} = REVY_j / REVHRCI_y$$

where:

REVHPCT$_j$ = the actual proportion of revenues allocated to customer class j in year y
REVY$_j$ = the actual revenues 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:

$$REVPCT_{jy} = REV_{jy} / REVRCI_y$$

where:

REVPCT$_{jy}$ = the modeled proportion of revenues allocated to customer class j in year y
REV$_y$ = 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:

$$SLSHPCT_{jy} = SALY_j / SLSHRCI_y$$

where:

SLSHPCT$_{jy}$ = the actual proportion of sales to customer class j
SALY$_j$ = the actual sales to customer class j in year y
SLSHRCI$_y$ = the actual sales to all three classes in year j

The modeled proportion of sales is:

$$SLSPCT_{jy} = SALCLS_{jy} / SLSRCI_y$$

where:

SLSPCT$_{jy}$ = the modeled proportion of sales to customer class j

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[97]This benchmarking/subsidization technique is not used for the generation or transmission transfer price calculations.

SALCLS$_{jy}$ = the modeled sales to customer class j in year y

SLSRCI$_y$ = the modeled sales to all three classes in year j

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:

$$SUBPCT_j = (REVHPCT_j - SLSHPCT_j) - (REVPCT_j - SLSPCT_j)$$

Calculation of Prices with Benchmarking and Subsidization:

After the benchmarking/subsidization proportion has been calculated, it is multiplied times 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:

$$EPRICE_j = (REV_j + (REVRCI \cdot SUBPCT_j))/(SALCLS_j)$$

where:

EPRICE$_j$ = the benchmarked/subsidized price of electricity to customer class j

REV$_j$ = the costs (revenues) allocated to customer class j before the benchmarking/subsidization routine

REVRCI = total costs allocated to the three customer classes

SUBPCT$_j$ = benchmarking/subsidy percent for customer class j

SALCLS$_j$ = electricity sales to customer class j

Sectoral Pricing Under Competition:

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_i is the consumer surplus of customer class I and θ_i is the weight that the decision maker attaches to I's level of welfare. The case where the decision maker is indifferent to the welfare of I is represented by $\theta_i = 0$. The case where the economic interests of I are twice as important as those of j can represented as by $\theta_i = 4/3$ and $\theta_j = 2/3$ while the case where I's interests are three times more "important" than j's would be represented by $\theta_i = 1.5$ and $\theta_j = .5$.

Our model is then

(1) $$Max \quad \theta_1 CS_1 + \theta_2 CS_2$$

such that:

(2) $$P_1 X_1 + P_2 X_2 - C(X_1, X_2) = 0.$$

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

$$(3) \qquad \frac{P_i - C_i^{/}}{P_i} = \frac{1 - \theta_i / \lambda}{|\varepsilon_i|},$$

where ε_i is sector I's price elasticity of demand, λ is a scalar to preserve feasibility of the solution, and $C_i^{/} = \partial C(X_1, X_2)/\partial X_i$ is the marginal cost of production. Inspection of (3) 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 I, then θ_i is zero in which case the price cost margin reduces to $1/|\varepsilon_i|$, a level equivalent to the unconstrained monopoly solution.

Now assume that the electricity is distributed by a regulated natural monopolist. We have three sectors: residential, commercial and industrial. Each sector purchases X_i (where X_i equals $\sum x_{f,i}$)from the generating industry at the price PG_i per unit. Assume the total cost of distribution is related to the amount of power distributed to each sector, i.e. the total cost of distribution is $C^D(X_1^S, X_2^S, X_3^S)$ where X_i^S is the amount of power that the distributor delivers to sector I through its system. In AEO99, the industrial and commercial sectors were assumed to have the threat of by-pass; that is, the ability to leave the system through self-generation or other means. We let $X_i^S = X_i - X_i^B$. Let η represent the elasticity of nongrid supply, i.e. $\eta = (\partial X_2^B/\partial P_2)(P_2/X_2^B)$, and S_i^D be the share of total generation purchased by the industrial sector that uses the distribution system, i.e., $S_2^D = X_2^S/X_2$. In contrast, the residential sector 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. $\partial X_2^B/\partial P_2 > 0$ where P_2 is the total end use price. Finally, assume that the end-use price is the sum of the generation price (PG_i) and the distribution charge (PD_i).

Based on the above discussion, the decision maker is assumed to maximize the function

$$(4) \qquad L = \theta_R CS_R + \theta_C CS_C + \theta_I CS_I + \lambda[PD_R X_R^S + PD_C X_C^S + PD_I X_I^S - CD(X_R^S, X_C^S, X_I^S)]$$

For the customers in the residential sector , $X_j^S = X_j$, and thus the following result can be obtained:

$$(5) \qquad PD_j = \frac{CD_j^{/} |\varepsilon_j| + PG_j(1 - \theta_j/\lambda)}{|\varepsilon_j| - (1 - \theta_j/\lambda)}$$

Customers in the industrial and commercial sectors are assumed to have the option to bypass the distribution system and thus, for instance, $X_I^S = X_I - X_I^B$. Let η represent the elasticity of nongrid supply, i.e. $\eta = (\partial X_I^B/\partial P_I)(P_I/X_I^B)$, and S_I^D be the share of total generation purchased by sector I that uses the distribution system, i.e., $S_I^D = X_I^S/X_I$.

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

$$(6) \qquad PD_I = \frac{\dfrac{CD_I^{/}}{S_D}[|\varepsilon_I| + \eta(1 - S_D)] + PG_I(1 - \theta_I/\lambda)}{\dfrac{1}{S_D}[|\varepsilon_I| + \eta(1 - S_D)] - (1 - \theta_I/\lambda)}$$

It is known that revenues must equal costs. Therefore:

$$(7) \qquad REV = \sum_1^3 \left(\frac{\dfrac{CD_I^{/}}{S_D}[|\varepsilon_I| + \eta(1 - S_D)] + PG_I(1 - \theta_I/\lambda)}{\dfrac{1}{S_D}[|\varepsilon_I| + \eta(1 - S_D)] - (1 - \theta_I/\lambda)} \right) Q(I)$$

where:

REV = total revenues required for transmission and distribution,

Q(I) = total consumption in sector I, and

S_D, CDI', ε_I, η, and θ_i are all known.

This is cubic in λ. The model then expresses λ as the polynomial equation,

(8)
$$coff(1)*\lambda^3 + coff(2)*\lambda^2 + coff(3)*\lambda + coff(4) = 0.$$

Defining:

(9)
$$\alpha(i) = newtd/Sdval* + (eps(I) + nuval*(1-Sdval)) + PG(I)$$
$$\beta(i) = -1*pg(I)*\theta(I,NERC)$$
$$\gamma(I) = (eps(i) + nuval*(1-Sdval))/Sdval - 1$$

Where:

newtd = marginal cost of T&D,

Sdval = fraction of consumption available for bypass,

Eps(I) = Elasticity of consumption for sector I,

Nuval = Elasticity of bypass for sector I,

PG(I) = Generation price to sector I,

NERC = NERC region.

(10)
$$COFF(1) = totrev*\theta(1,NERC)*\theta(2,NERC)*\theta(3,NERC)$$
$$-\beta(1)*(Q(1)+transal)*\theta(2,NERC)*\theta(3,NERC)$$
$$-\beta(2)*Q(2)*\theta(1,NERC)*\theta(3,NERC)$$
$$-\beta(3)*(Q(3))*\theta(2,NERC)*\theta(1,NERC)$$

where:

totrev = total revenues required for T&D,

Q(I) = consumption of electricity in sector I, and

Transal = consumption of electricity in transportation sector.

(11)
$$COFF(2) = totrev*(\theta(1,NERC)*\theta(3,NERC)*\gamma(2)$$
$$+\gamma(1)*\theta(2,NERC)*\theta(3,NERC)+\theta(1,NERC)*\theta(2,NERC)*\gamma(3))$$
$$-(Q(1)+transal)*(\alpha(1)*\theta(2,NERC)*\theta(3,NERC)$$
$$+\beta(1)*\gamma(3)*\theta(2,NERC)+\beta(1)*\gamma(2)*\theta(3,NERC))$$
$$-Q(2)*(\alpha(2)*\theta(1,NERC)*\theta(3,NERC)+\beta(2)*\gamma(3)$$
$$*\theta(1,NERC)+\beta(2)*\gamma(1)*\theta(3,NERC)$$

(12)
$$COFF(3) = totrev*(\theta(1,NERC)*\gamma(2)*\gamma(3)+\theta(2,NERC)*\gamma(1)*\gamma(3)$$
$$+\theta(3,NERC)*\gamma(1)*\gamma(2))-(Q(1)+transal)*(\alpha(1)*\gamma(3)*\theta(2,NERC)$$
$$+\alpha(1)*\gamma(2)*\theta(3,NERC)+\beta(1)*\gamma(2)*\gamma(3))$$
$$-Q(2)*(\alpha(2)*\gamma(3)*\theta(1,NERC)+\alpha(2)*\gamma(1)*\theta(3,NERC)+\beta(2)*\gamma(1)*\gamma(3))$$
$$-(Q(3))*(\alpha(3)*\gamma(2)*\theta(1,NERC)+\alpha(3)*\gamma(1)*\theta(2,NERC)+\beta(3)*\gamma(1)*\gamma(2))$$

(13)
$$COFF(4) = totrev*\gamma(1)*\gamma(2)*\gamma(3)-\alpha(1)*(Q(1)+transal)*\gamma(2)*\gamma(3)$$
$$-\alpha(2)*Q(2)*\gamma(1)*\gamma(3)-\alpha(3)*Q(3)*\gamma(1)*\gamma(2)$$

A Newton-Raphson iterative method is used to solve for λ. Given λ, Equation (6) 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 (8) 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_l, the total consumption by sector, and 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 t for sector j is projected to be equal to its share in 2020 multiplied times a logistical market penetration factor:

$$Nationalshr(j,t) = Nationalshr(j,2020) * \frac{(\exp(t-midyear))}{(1+\exp(t-midyear))}$$

where:
midyear   =   midpoint of forecast, and
Nationalshr(j,t) =   share of bypass in sector j year t.

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

$$allocationweight(j,r) = \frac{\ln(Markup(j,r)+\ln(Consfactor(j,r))}{\sum_r[\ln(Markup(j,r)+\ln(Consfactor(j,r)]}$$

where:

Markup(j,r)   =   markup of the generation price over marginal cost for sector j in region r
Consfactor(j,r)   =   ratio of average consumption per customer in sector j in region r relative to the average consumption for sector 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

$$Normalizationfactor(j,t) = \frac{Nationalshr(j,t)}{\sum_r conshr(j,r,t)*allocationweight(j,r)}$$

where:
conshr(j,r,t)   =   share of sector j's national consumption in region r, year t.

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:

Calculation of Regional Factor:

Each region must then maintain

$$Normalization factor(j,t) = \frac{Nationalshr(j,t)}{\sum_r conshr(j,r,t) * allocationweight(j,r)}$$

where conshr(j,r,t) is the share of sector j's national consumption in region r, year t.

It follows that the bypass share will be:

$$bypassshr(j,t) = Normalization factor(j,t) * allocationweight(j,r)$$

The resulting regional shares are used to calculate sectoral prices by region in equations (6)-(13) 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, AEO2001 assumes this region to be fully or partially competitive. AEO2001 assumes 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:

$$compSLSHPCT_{ry} = totcompSLSHPCT_{ry} * (10\% * compyear_r)$$

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)

Within a competitive region, AEO2001 assumes 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:

$$EPRICE_{jry} = (regEPRICE_{jry} * \% \ regSLSHPCT_{jry}) + (compEPRICE_{jry} * \% \ compSLSHPCT_{jry})$$

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 that has 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 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 kilowatt-hour 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.

$$EPRICE_{jry} = EPRICE_{jry} \text{ - weighted price reduction}_{jry}$$

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.

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.

$$GENTAX = EGTXRT \cdot ERRVLG + ERPRTX + ERSLTX$$

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.

$$CITAX = (ERRVLG - ERTFLN - ERTOMN - ERTDWO - GENTAX - (ERTIEX - AVDINT) - ESLLP)$$
$$\cdot ESFTXR + STTAX - (ERFITC + XITCD) - (ERATSF + ERATSD)$$

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 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:

$$BKITAX = CITAX + (XITCD - ERAITC) + (ERXFDC - ERAFDC) + ERATSD - EREDTF$$

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):

$$STTAX = (ERRVLG - ERTFLN - ERTOMN - ERTDWO - ERTIEX - ESLLP) \cdot ESSTXR \cdot (1 - ESFTXR)$$

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 under 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)   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 V.A. Functional Description Calculation of the Reliability Component

Subroutine: ELREL

Description: This subroutine calculates the reliability component of marginal cost. 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.

Called by: COMPPRC

Calls: DELEUE, SHAVEL

Equations: There are 6 seasons, and 18 slices per season. We calculate marginal expected unserved energy for each slice independently. Rather than calculate the derivative of expected unserved energy, we approximate it by a differential.

We define the marginal capacity function as the stochastic function

$$M = G - L$$

where: $L(l)$ = density function for load (demand), and

$G(g)$ = density function for generating capacity.

We define unserved energy as the stochastic variable

$$UE = \begin{cases} m, m < 0 \\ 0, otherwise \end{cases}$$

and expected unserved energy

$$EUE = \int_0^{Z1} m M_x(m) dm$$

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, we calculate the cumulants of the marginal capacity function:

$$tdcum1(icm) = capcum(ise, icmRNB, 1) + dcum(sblkicm, RNB) * (-1)^{icm}$$

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, and

$$tdcum2(icm) = capcum(ise, icmRNB, 2) + dcum(sblkicm, RNB) * (-1)^{icm}$$

where:

tdcum2	=	marginal capacity cumulant icm for the slice,
capcum2	=	capacity cumulant (with increment) icm for season ise, region RNB, and
dcum	=	demand cumulant icm for slice sblk and region RNB.

Next we calculate the standard deviation of the distributions

$$sdev1 = \sqrt{tdcum1(2)}$$

$$sdev2 = \sqrt{tdcum2(2)}$$

and the normalized mean of the marginal capacity function. The subroutine DELEUE finds the change in margin unserved energy from these quantities.

Subroutine: SHAVEL

Description: Computes the Shavel/Sanghvi approximation to the cumulative distribution at a point z given its first four cumulants. This is based on first few terms of the Gram-Charlier expression of a distribution as an infinite series of its cumulants.

Parameters:
z	=	z-value (input)
cum1	=	first cumulant of marginal capacity function
cum2	=	second cumulant of marginal capacity function
cum3	=	third cumulant of marginal capacity function
cum4	=	fourth cumulant of marginal capacity function
cum	=	cumulative distribution (output)

Called by: ELREL, EMUE

Calls: NORM

Equations:

$$g1 = \frac{cum3}{cum2^{1.5}}$$

$$g2 = \frac{cum4}{cum2^2}$$

$$norm0 = pinorm * \exp^{-\frac{z^2}{2}}$$

$$call \ norm(z1, \ norm0, \ normx1)$$

$$cum = normx1 - \frac{g1 * norm0 * (z^2 - 1)}{6!} + \frac{g2 * norm0 * (3z - z^3))}{4!} + \frac{g1^2 * 10 * norm0 * (10z^3 - 5z - z^5)}{6!}$$

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.

Function: NORM

Description:	NORM finds the cumulative normal probability distribution for any value z1.
Called by:	DELEUE
Calls:	None.
Parameters:	dens = normal density evaluated at z1
Equations:	data a/0.2316419/
	data b/0.31938153,-0.356563782,1.781477937,-1.821255978,1.330274429/

$$val3 = \sum_{i=1}^{5} b_i * (\frac{1.0}{1.0 + a * z1})^i$$

where:

val3	=	intermediate value,
b	=	constant, and
a	=	constant.

$$cum = 1.0 - dens * val3$$

where:

cum	=	cumulative distribution evaluated at z1, and
dens	=	normal density evaluated at z1.

Function: DELEUE

Description:	Develops the contribution of a unit of capacity of a particular ECP type to the reduction in marginal expected unserved energy.
Called by:	DELEUE
Calls:	Shavel.
Equations:	Determine loss of load probability (LOLP)
	CALL Shavel(cum1,cum2,cum3,cum4,LOLP)

$$G1 = (\frac{cum3}{cum2})^{3/2}$$

$$DELEUE = 0 + DZ1(for,cap,cum1,cum2) * LOLP - DG1(for,cap,cum2,cum3)$$
$$+ \frac{N2(z14)}{3!} + \frac{DG2(for,cap,cum2,cum4) * N3(z14)}{4!}$$
$$+ \frac{2 * G1 * DG1(for,cap,cum2,cum3) * 10 * N5(z14)}{6!}$$

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.

Function: DZ1

Description: DZ1 creates the coefficient for the third order term of the approximation of marginal
                    unserved energy function for the ECP.
Called by: DELEUE
Calls: None.
Equation:

$$DZ1 = -for * \sqrt{cum2} - .5 * (-1 * cum1) * for * (1 - for) * cap * cum2^{-3/2}$$

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.

Function: DG2
Description: DG2 creates the coefficient for the fourth order term of the approximation of marginal
                    unserved energy function for the ECP.
Called by: DELEUE
Calls: None.
Equation:

$$DG2 = for * cap^3 * (1 - 7 * for + 12 * for^2 - 6 * for^3)$$
$$* cum2^{-2} - 2 * cum4 * for * cap * (1 - for) * cum2^{-3}$$

where:
for   =   forced outage rate,
cap   =   size of the unit (Gigawatts),
cum2   =   second cumulant of the marginal capacity function, and
cum4   =   fourth order cumulant of the marginal capacity function.

Function: DG1
Description: DG1 creates the coefficient for the second order term of the approximation of marginal
                    unserved energy function for the ECP.
Called by: DELEUE
Calls: None.
Equation:

$$DG1 = for * cap^2 * (1 - 3 * for + 2 * for^2)$$
$$* cum2^{3/2} - 1.5 * cum3 * for * cap * (1 - for) * cum2^{-5/2}$$

where:
for   =   forced outage rate,
z3   =   mean of the marginal capacity function,
cap   =   size of the unit (Gigawatts),
cum2   =   second cumulant of marginal capacity function, and
cum3   =   third cumulant of marginal capacity function.

Function: N2
Description: N2 creates the coefficient for the second order term for the approximation of marginal
                    unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N2 = -1 * (z2^2 - 1.0) * pinorm * Exp\frac{-z2^2}{2}$$

where:

pinorm=   0.39894228040, and

z2   =   mean of the marginal capacity function.

Function: N3

Description: N3 creates the coefficient for the third order term for the approximation of marginal
                 unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N3 = -1 * (z3^3 - 3 * z3) * pinorm * Exp(\frac{-z3^2}{2})$$

where:

pinorm=   0.39894228040, and

z3   =   mean of the marginal capacity function.

Function: N5

Description: N5 creates the coefficient for the fifth order term for the approximation of marginal
                 unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N5 = -1 * (z5^5 - 10 * z5^3 + 15 * z5) * pinorm * Exp(\frac{-z5^2}{2})$$

where:

pinorm=   0.39894228040, and

z5   =   mean of the marginal capacity function.