

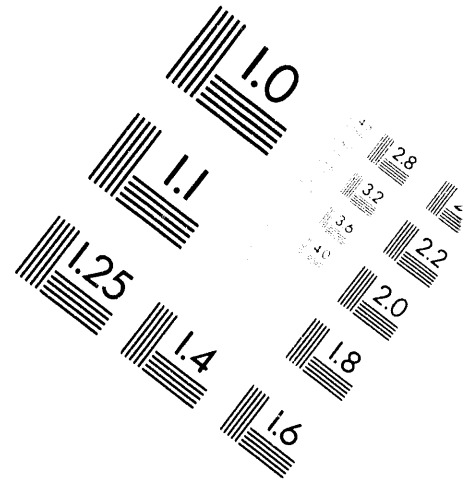
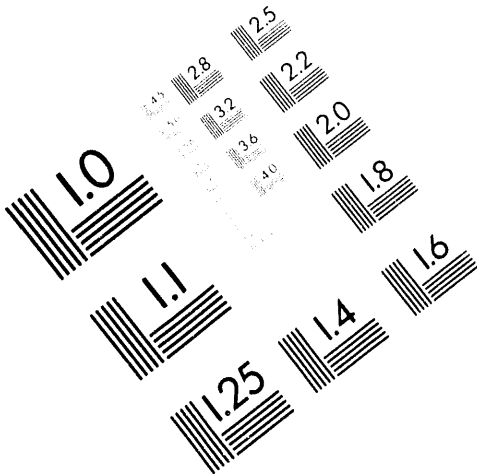


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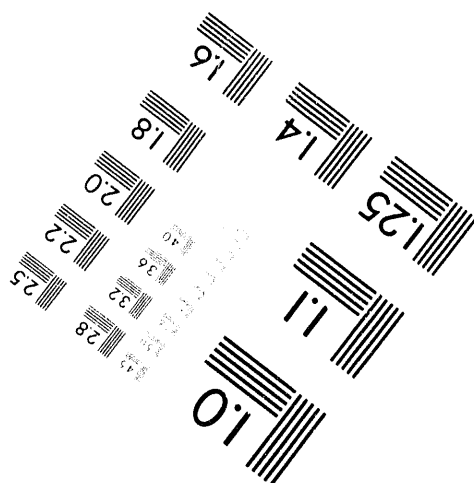
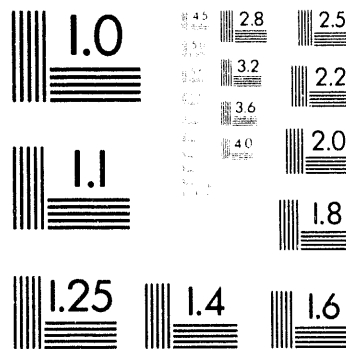
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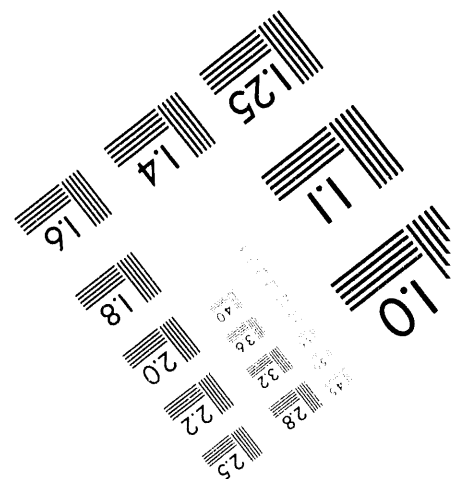
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Model Documentation:

Electricity Market Module

Electricity Capacity Planning Submodule

March 1994

Energy Information Administration
Office of Integrated Analysis and Forecasting
Energy Supply and Conversion Division
Nuclear and Electricity Analysis Branch
U.S. Department of Energy
Washington, DC 20585

MASTER

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1. INTRODUCTION

1.1 Purpose of the Report

The National Energy Modeling System (NEMS) is a computer modeling system developed by the Energy Information Administration (EIA). The NEMS produces integrated forecasts for energy markets in the United States by achieving a general equilibrium solution for energy supply and demand. Currently, for each year during the period from 1990 through 2010, the NEMS describes energy supply, conversion, consumption, and pricing. It contains individual modules to represent specific fuel supply industries, conversion activities, and end-use consumption sectors.¹ The NEMS provided energy forecasts for the *Annual Energy Outlook 1994*.² It replaced the Intermediate Future Forecasting System (IFFS), which was used by EIA to produce the *Annual Energy Outlook* and other analyses from 1982 through 1993.³

The Electricity Market Module (EMM) is the electricity supply component of the National Energy Modeling System (NEMS). The supply of electricity is a conversion activity since electricity is produced from other energy sources (e.g., fossil, nuclear, and renewable). The EMM represents the generation, transmission, and pricing of electricity. The EMM consists of four main submodules: Electricity Capacity Planning (ECP), Electricity Fuel Dispatching (EFD), Electricity Finance and Pricing (EFP), and Load and Demand-Side Management (LDSM). The ECP evaluates changes in the mix of generating capacity that are necessary to meet future demands for electricity and comply with environmental regulations. The EFD represents dispatching (i.e., operating) decisions and determines how to allocate available capacity to meet the current demand for electricity. Using investment expenditures from the ECP and operating costs from the EFD, the EFP calculates the price of electricity, accounting for state-level regulations involving the allocation of costs. The LDSM translates annual demands for electricity into distributions that describe hourly, seasonal, and time-of-day variations. These distributions are used by the EFD and the ECP to determine the quantity and types of generating capacity that are required to insure reliable and economical supplies of electricity. The EMM also represents nonutility suppliers and interregional and international transmission and trade. These activities are included in the EFD and the ECP.

This report documents the objectives and analytical approach of the 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. It is intended as a reference document providing a detailed description of the model for analysts, users and the public. It is also intended to meet the legal obligation of the Energy Information Administration (EIA) to provide adequate documentation in support of its models (Public Law 93-275, section 57(b)(1)). The EFD, EFP, and LDSM are documented in separate reports.

1.2 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

¹The National Energy Modeling System also contains modules representing international energy markets and macroeconomic activity. For additional information, see Energy Information Administration, *NEMS Integrating Module Documentation Report*, DOE/EIA-M057 (Washington, DC, December 1993).

²Energy Information Administration, *Annual Energy Outlook 1994*, DOE/EIA-0383(94) (Washington, DC, January 1994).

³For additional information, see Energy Information Administration, *Intermediate Future Forecasting System: Executive Summary*, DOE/EIA-0430 (Washington, DC, October 1983).

achieving the emissions restrictions in the CAAA include installing pollution control equipment on existing power plants, implementing DSM programs, and building new power plants with low emission rates.⁴ The ECP also considers "banking" emissions allowances (i.e., each year utilities are allocated allowances that entitle them to emit sulfur dioxide (SO₂) 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 overcomplying at an existing unit. The ECP is also capable of representing regulations for carbon emissions and externality costs for various pollutants.

Potential options for new generating capacity include fossil-fuel, nuclear, and renewable power plants, including intermittent technologies such as solar and wind. Both utility and nonutility suppliers are evaluated together as sources of new generating capability. 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 will compete with conventional plant types as sources of supply in the ECP. However, the representation of new technologies is limited in the current version of the EMM. A future enhancement will incorporate the New Technologies Submodule, which will consider the impacts of learning effects, risk and uncertainty.⁵ Similarly, the ECP contains structure to compete supply and demand options (i.e., the need for new capacity can be reduced by programs to lower or shift demand), but the penetration of demand-side management (DSM) programs is not presently determined because the required linkages with the LDSM Submodule have not yet been completed. Future enhancements are also planned to include life extension and repowering decisions in the ECP.

1.3 Model Contact and Archival Citation

- **Model Name:** Electricity Capacity Planning Submodule
- **Model Acronym:** ECP
- **Office:** Integrated Analysis and Forecasting
- **Division:** Energy Supply and Conversion
- **Branch:** Nuclear and Electricity Analysis
- **Contact:** Jeffrey S. Jones
EI-821
U.S. Department of Energy
1000 Independence Avenue S.W.
Washington, D.C. 20585
(202) 586-2038
- **Archival Citation:** The ECP will be archived as part of the NEMS for the version used for the *Annual Energy Outlook 1994*. This will be available in early 1994.

⁴For a more detailed description of the Clean Air Act Amendments, see Energy Information Administration, *Component Design Report Electricity Fuel Dispatch* (Washington, DC, May 1992).

⁵For a more detailed description, see Energy Information Administration, *NEMS Component Design Report Modeling Technology Penetration* (Washington, DC, March 1993).

1.4 Report Organization

The remainder of this report is presented in the following order:

Chapter 2. Model Purpose

This chapter provides a description of the objectives of the ECP, the interaction of the model with other submodules of the EMM and components of the NEMS, and levels of aggregation represented in the model.

Chapter 3. Model Overview and Rationale

This chapter summarizes the theoretical approach and fundamental assumptions used in the ECP. It also discusses alternative approaches for modeling planning decisions, including the model previously used by the EIA.

Chapter 4. Model Structure

This chapter provides a detailed description of the solution algorithm for the ECP, which uses a linear programming formulation to determine planning decisions. It includes the mathematical specification of the objective function and constraint matrix.

Appendix

The appendices contain a detailed inventory of the input data, parameter estimates, and model outputs. They provide a correspondence between the variables in the documentation and their location in the computer code. Included is a description of the FORTRAN subroutines and equations used to derive the coefficients of the objective function and the constraints of the linear programming model. Additional information includes a bibliography and a model abstract.

2. MODEL PURPOSE

2.1 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 and capture changes in the competitive structure, such as the penetration of nonutility suppliers, and responses to environmental regulations, such as the CAAA or limits on carbon emissions. It represents traditional and nontraditional sources of supply.

Technology choices in the ECP includes all of the fuel types used by electric utilities—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 are expected to include atmospheric fluidized bed, pressurized fluidized bed, integrated gasification combined cycle, fuel cells, and advanced nuclear reactors, although initially generic technologies will be represented. Renewable technologies include geothermal, biomass (wood), and municipal solid waste. Intermittent renewable capacity (e.g., wind and solar) will also be considered.

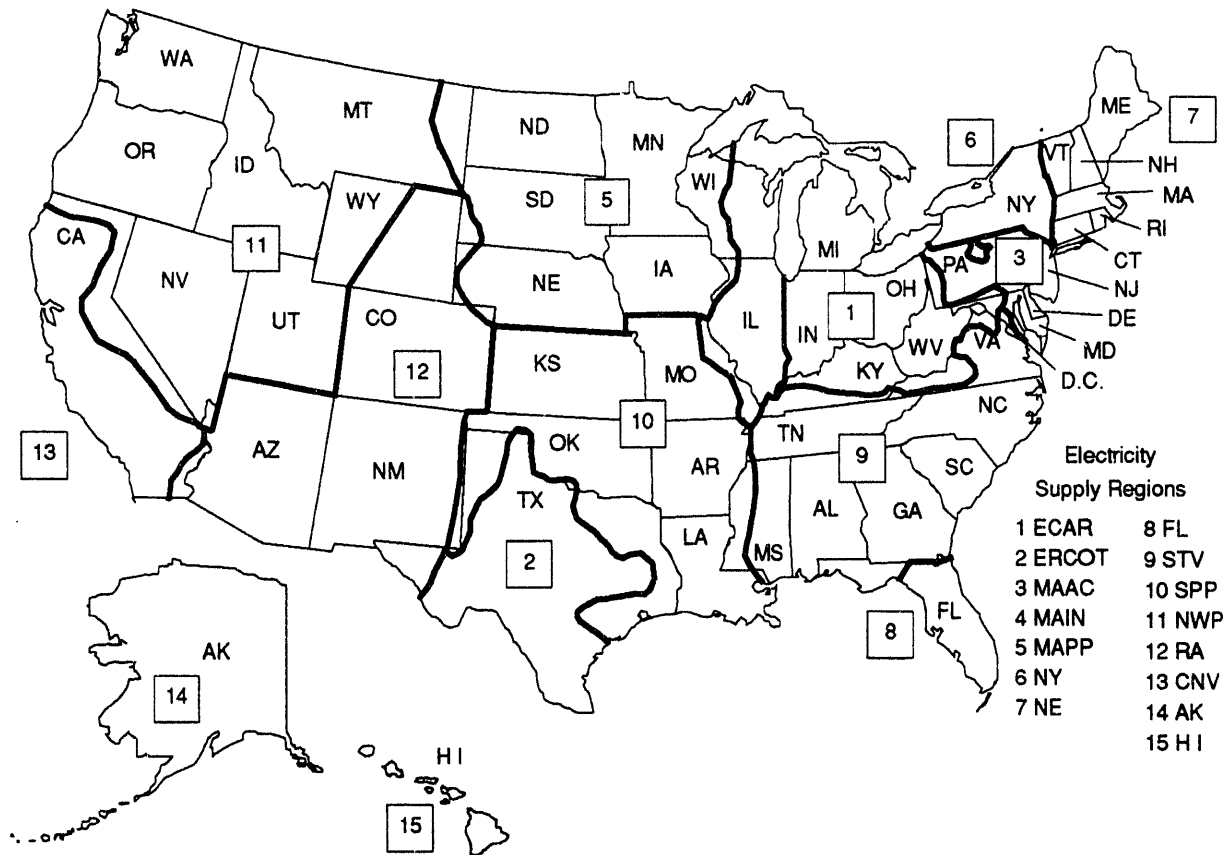
In the ECP, planning decisions are currently represented for 13 electricity supply regions (Figure 1). In the future, two additional regions for Alaska (AK) and Hawaii (HI) will be added. Of the 13 regions, 6 correspond to North American Electric Reliability Council (NERC) Regions. These are the East 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.⁶ 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 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 2010. 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 (utility and nonutility) and the

⁶The 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 (Washington, DC, December 1993).

Figure 1. Electricity Supply Regions



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 intraregional 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). When the linkages are completed, the ECP can also consider the competition between supply-side and demand-side options for meeting demand growth and environmental regulations. Similarly, the development of the New Technologies Submodules will enable the ECP to examine key issues related to the introduction of advanced technologies, such as learning effects, risk, and uncertainty.

2.2 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 2). Exogenous inputs include existing operable capacity, planned capacity additions, and announced capacity retirements⁷. Data inputs also include the age of existing units include the remaining life, 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. Transmission and trade, and nonutility capacity data inputs are also exogenously specified. Non-utility input data include planned nonutility additions and cost and performance characteristics for nonutility capacity additions. 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 decreases 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.

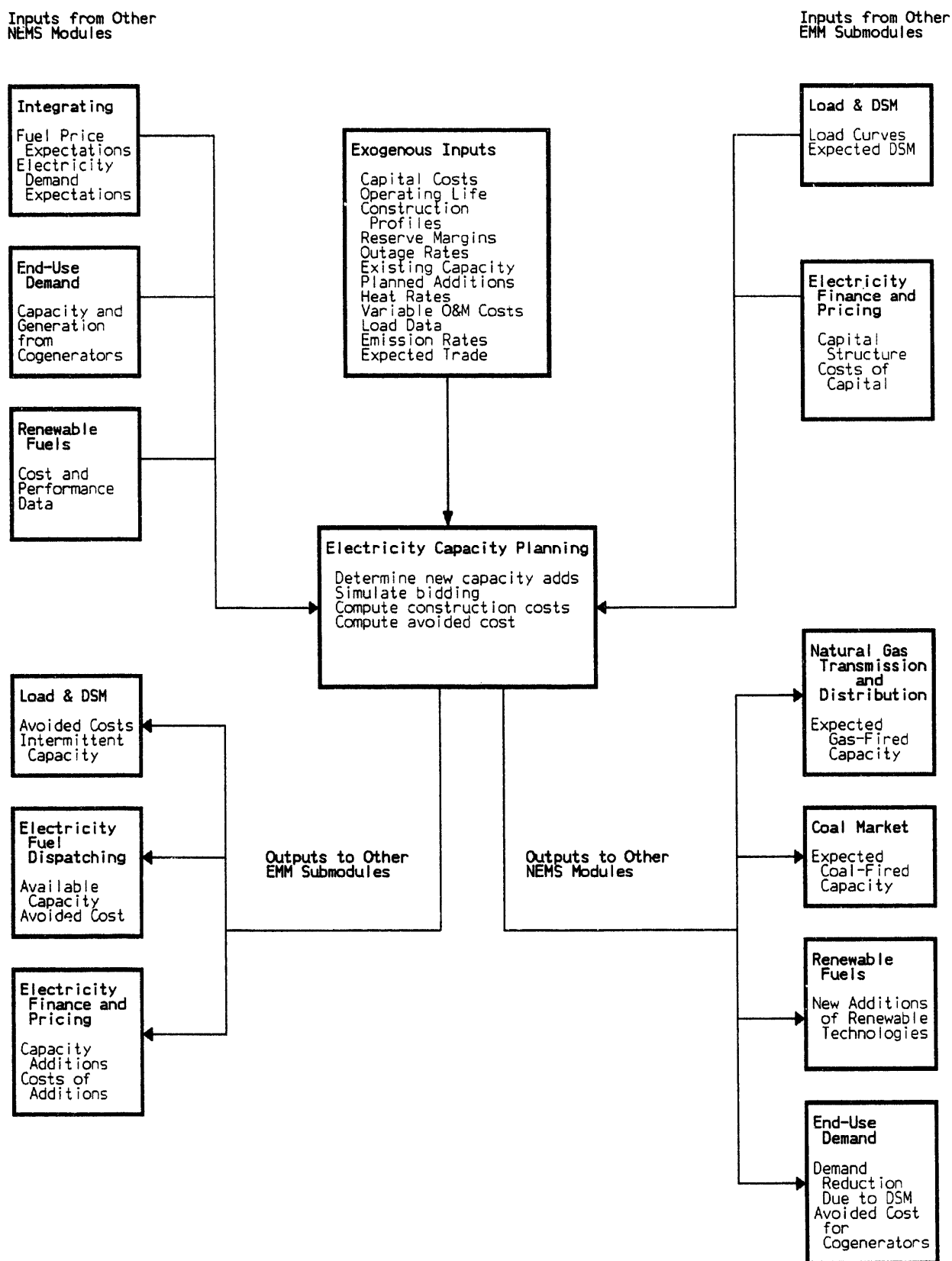
The Electricity Finance and Pricing (EFP) Submodule supplies the capital structure (debt/equity shares) and the cost of capital. When the linkages are completed, the Load and Demand-Side Management (LDSM) Submodule will furnish the load curves and the costs and impacts of DSM programs.

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 2). Capacity additions for coal- and gas-fired generating capacity are provided to the Coal Market Module (CSM) 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. The ECP will also provide avoided costs to the LDSM Submodule for the

⁷Generating units placed into service prior to the first model year (1990) are considered existing capacity. Units that begin operation thereafter are considered new capacity.

Figure 2. Input/Output Flows for Electricity Capacity Planning (ECP) Submodule of the EMM



evaluation of demand-side resource options.⁸ The LDSM Submodule will also use the level of capacity for intermittent technologies to adjust the load curves. However, the required data flows between the LDSM and other components of the EMM have not been completed so the LDSM was not used to produce the *Annual Energy Outlook 1994*.

⁸For information on the calculation of avoided costs, see Energy Information Administration, *Component Design Report Nonutility Generation Supply* (Washington, DC, May 1992).

3. MODEL OVERVIEW AND RATIONALE

3.1 Theoretical Approach

The ECP uses a 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 leadtimes, such as construction of peaking units or implementation of DSM programs. 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.

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.

Decisions to invest in DSM may also involve a multi-period evaluation. Some of these programs are phased-in over time so that the impact grows until it reaches its maximum level. The attractiveness of the investment depends on the combined impact over the years, which is affected by the date of program initiation and the rate in which the program is phased-in. A delay in initiating the program may diminish the potential impact, depending on the supply option it would replace. The ECP will evaluate the implementation of a particular DSM program in each year of the planning horizon and select the initiation date, if any, that results in the lowest combination of investment and operating costs (present value) for all years.

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 undercomply 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.⁹ 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.

⁹The 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 (Section 3.2). Maintaining the chronological identity of the demands for electric power allows the ECP to better represent time-dependent variations in both the demand for and supply of electricity.

In the ECP, the available supply options are characterized by the degree of control they provide the operator of the system. Assuming adequate fuel supplies, fossil-fuel and nuclear units are considered "dispatchable" since they can usually 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).

DSM programs can be used to offset the need for additional supplies or reallocate the use of existing supplies. DSM can alter load requirements, either by reducing demand (including switching to an alternate fuel such as electric-to-gas air conditioning) or by shifting it from peak to off-peak periods. Like the intermittent technologies, these programs may be effective only for certain load segments. For example, switches to cycle air conditioners on and off will only impact power demand during the summer. The attractiveness of DSM programs depends on several factors, including load characteristics, effective reserve margins, the attitude of state regulators, legal mandates, and rate and cost recovery schedules.¹⁰

Although the ECP structure is designed to represent investment decisions for DSM programs, it did not include an endogenous representation of DSM for the *Annual Energy Outlook 1994* because the required linkages with the LDSM have not been completed. Furthermore, the ECP represents conventional and advanced technologies as separate capacity types, but the New Technologies Submodule has not been implemented so the penetration of new technologies is limited by the absence of key factors such as learning effects, technological optimism, risk, and uncertainty. Also, some of the required interactions with the Renewable Fuels Module (RFM) are not completed, so several of the necessary data transfers (i.e. cost and performance characteristics) are currently incorporated as input data within the ECP.

In the Component Design Report (CDR) for the ECP, it was proposed to augment the LP model with a market-sharing algorithm that adjusts the solution from the LP model to allow penetration of "competitive" but not "least-cost" alternatives.¹¹ 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. To deal with this issue, the CDR described a methodology to adjust the decisions from the LP model using a procedure to evaluate technologies that do not penetrate based on average costs but that may actually be competitive with the capacity types that are selected. The current version of the ECP does not contain the proposed market-sharing algorithm.

In the CDR, a ten-year planning horizon was recommended. However, the size of the model was restricted by the software used to solve the LP. Therefore, the current version of the ECP examines planning

¹⁰For a more specific discussion of DSM programs, see Energy Information Administration, *Component Design Report Load and Demand-Side Management Submodule* (Washington, DC, October 1992).

¹¹For more information see Energy Information Administration, *Component Design Report Electricity Capacity Planning* (Washington, DC, August 1992).

decisions during a six-year period, including the current forecast year.¹² This required some adjustments to the proposed formulation. Some supply options such as coal-fired steam plants have leadtimes that exceed the length of the planning horizon. Since the model evaluates decisions that are initiated and completed during the planning horizon, it was necessary to compress licensing and construction periods for longer leadtime options. For instance, a new coal-fired project typically requires 6 to 8 years before it begins commercial operation. In the ECP, a four-year schedule is assumed because of the 6-year planning horizon. In order to compensate for the shortened leadtime, the initial availability of new capacity for each plant type is not permitted until the actual leadtime has elapsed.¹³ The construction expenditure profiles (the percent of total expenditures incurred in each year of construction) are also "front-loaded" so that the total cost of building new capacity, are essentially equivalent to the corresponding costs based on the longer construction leadtime. Otherwise, the interest charges and the present value of the construction expenditures would be underestimated as a result of the compressed leadtime.

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.¹⁴ 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).¹⁵ 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.¹⁶

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.

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.¹⁷ Capacity additions of renewable technologies were exogenous inputs. Domestic and international bulk power purchases were also exogenous assumptions. Furthermore, the planning component of the IFFS did 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) and demand-side management (DSM) programs 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, which plot demands for electric power (loads) versus time (i.e., the number of hours that a given load exists). The loads were

¹²In the ECP, each cost (e.g., capital and fuel) for the final year of the six-year planning horizon actually represents the sum of the present value of corresponding expenditures in years 6 through 30 so that decisions can be evaluated over a 30-year period.

¹³For example, a new coal-fired that is not already planned or under construction could not begin operation until at least 2000. In the ECP, the option to initiate and complete a coal-fired unit during the 1990's is excluded.

¹⁴For 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).

¹⁵In 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).

¹⁶The 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.

¹⁷A 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).

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 and DSM programs.

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.¹⁸ 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.

3.2 Fundamental Assumptions

It is assumed that capacity additions that have been announced by utilities and nonutilities will be completed as reported.¹⁹ 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. It is assumed that most of this capacity will be maintained and operated throughout the forecast period.²⁰ Thus, the ECP only determines capacity additions over and above those projects currently planned or under construction. It includes both utility and nonutility suppliers. However, contributions from cogenerators are determined by the end-use demand modules.

The capacity additions determined by the ECP must be sufficient to satisfy minimum reliability requirements in each of the electricity supply regions. In the ECP, 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.²¹

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. For the *Annual Energy Outlook 1994*, adaptive expectations, which assume that future trends can be extrapolated from historical patterns, are used for future demands and prices.²² 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

¹⁸For a detailed description of the NCM, see Energy Information Administration, *National Coal Model: Executive Summary*, DOE/EIA-0325 (Washington, DC, April 1982).

¹⁹Planned 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".

²⁰Units that are life-extended are assumed to maintain their current level of performance. For more details on life-extension and other assumptions see Energy Information Administration, *Assumptions for the Annual Energy Outlook 1994*, (Washington, DC, forthcoming).

²¹These projections are contained in North American Electric Reliability, *Electricity Supply & Demand 1992-2001* (Princeton, NJ, June 1992).

²²For more information on foresight assumptions for the AEO94, see Energy Information Administration, *NEMS Integrating Module Documentation Report*, DOE/EIA-M057 (Washington, DC, December 1993).

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 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 and DSM programs.

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

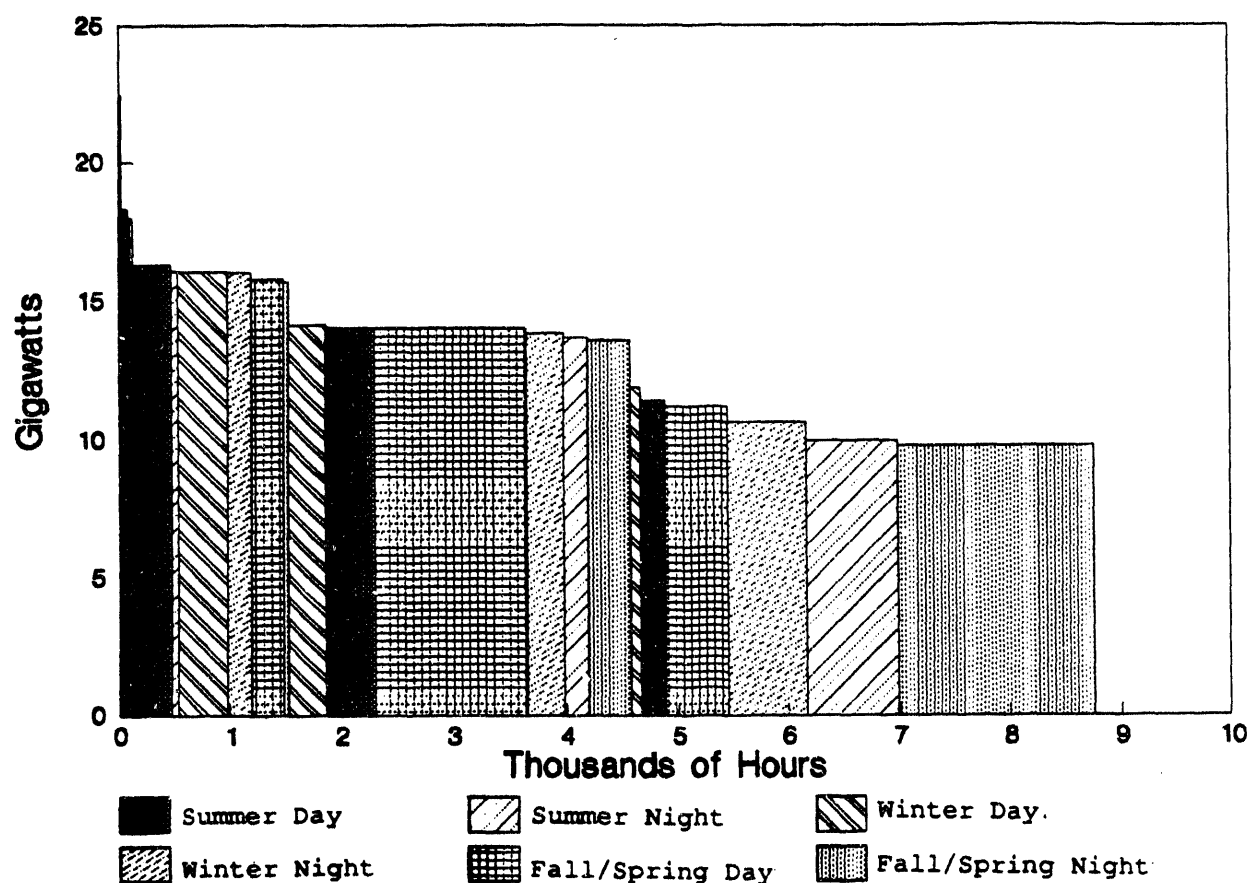
Load Group	Months	Hours
Summer Daytime	June - September	7:00 a.m. - 6:00 p.m.
Summer Morning/Evening	June - September	5:00 a.m. - 7:00 a.m., 6:00 p.m. - 12:00 p.m.
Summer Night	June - September	12:00 p.m. - 5:00 a.m.
Winter Daytime	December - March	7:00 a.m. - 6:00 p.m.
Winter Morning/Evening	December - 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 peak and offpeak loads. In order to improve the approximation, a third (near-peak) slice is added for the four categories with the most variation (summer daytime, summer morning/evening, winter daytime, and winter morning evening). For each region, the resulting 22 blocks are then arranged in descending order to produce the load duration curve (Figure 3).

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 intraregional 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.²³ It has been assumed that this initial capability (as of 1992)

²³Interregional transmission constraints are derived from Department of Energy, Form OE-411, "Coordinated Bulk Power Supply Program Report".

Figure 3. Load Duration Curve with Time-of-Day and Seasonal Load Segmentation



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.

In the ECP, available supply options include fossil-fired, nuclear, and renewable technologies (Table 2). For a given electricity supply region, the existing capacity for each category represents the sum of all the operating units for that capacity type. In the *Annual Energy Outlook 1994*, it is assumed that no new nuclear units will be ordered through 2010 due to concerns about radioactive waste disposal, safety, economic and financial risk, and uncertainty in the licensing and regulatory process.²⁴ Capacity additions for hydroelectric, biomass, and municipal solid waste plants, unlike other renewable technologies (i.e., geothermal, solar, and wind), do not compete within the ECP, but are exogenously specified by the Renewable Fuels Module. The commercial availability of new technologies is also an exogenous input.²⁵

Potential options for reducing SO₂ 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.

²⁴For more information, see Energy Information Administration, *Supplement to the Annual Energy Outlook 1994* (Washington, DC, forthcoming).

²⁵For more information, see Energy Information Administration, *Requirements for a National Energy Modeling System* (Washington, DC, November 1991).

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 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 SO₂ 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 SO₂ 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 2. Capacity Types Represented in the Electricity Capacity Planning Submodule

Category
Existing Unscrubbed Coal with SO ₂ standard \leq 1.20 lbs / Million Btu
Existing Unscrubbed Coal with SO ₂ standard \leq 2.50 lbs / Million Btu
Existing Unscrubbed Coal with SO ₂ standard \leq 3.34 lbs / Million Btu
Existing Unscrubbed Coal with SO ₂ standard $>$ 3.34 lbs / Million Btu
Existing Scrubbed Coal with SO ₂ standard \leq 1.20 lbs / Million Btu
Existing Scrubbed Coal with SO ₂ standard \leq 2.50 lbs / Million Btu
Existing Scrubbed Coal with SO ₂ standard \leq 3.34 lbs / Million Btu
Existing Scrubbed Coal with SO ₂ standard $>$ 3.34 lbs / Million Btu
New Pulverized Coal with Scrubber
Advanced Clean Coal Technology
Gas/Oil Steam (New or existing)
Conventional Gas/Oil Combined Cycle (New or existing)
Advanced Gas/Oil Combined Cycle
Conventional Combustion Turbine (New or existing)
Advanced Combustion Turbine
Conventional Nuclear (New or existing)
Advanced Nuclear
Conventional Hydroelectric
Pump Storage Hydroelectric
Geothermal
Biomass
Municipal Solid Waste
Solar
Wind

3.3 Alternative Approaches and Reasons for Selection

Planning decisions for the electric power industry are affected by a number of increasingly complex issues, including the ability of demand-side programs to modify load shapes, the capability of non-regulated utility suppliers (NUGS) to compete for market shares of electricity production based on the avoided cost of expansion for investor-owned utilities (IOU), and the expanded influence of advanced technologies as economic competitors with conventional technologies in the marketplace. In this context, seven capacity expansion models have been examined:

- Electric Generation Expansion Analysis System (EGEAS), from the Electric Power Research Institute (EPRI) and Stone and Webster Management Consultants, Inc.
- Integrated Utility Planning and Analysis System (PROSCREEN II), from Energy Management Associates, Inc.
- Electric and Gas Utility Modeling System (EGUMS), from the U.S. Environmental Protection Agency and RCG/Hagler, Bailly, Inc.
- National Energy Strategy Integrating Forecasting Model (FOSSIL2), from the U.S. Department of Energy.
- Advanced Utility Simulation Model and Utility Planning and Coal Demand Module (AUSM/UPCODE), from the U.S. Environmental Protection Agency and Science Applications International Corporation.
- Argonne Utility Simulation Model (ARGUS), from the U.S. Department of Energy, Argonne National Laboratory.
- OVER/UNDER Capacity Planning Model, from the Electric Power Research Institute and Decision Focus Incorporated.

While each of the models reviewed is a very useful tool for their intended audience, none of them meet all of the requirements of the ECP. Some of the models are not designed to operate at a regional level, require a large amount of unit and system specific data not normally available to EIA, do not explicitly compete DSM programs with supply options, are narrowly focused on a particular issue (i.e., environmental impacts), do not represent the nonutility sector, and do not address many of the issues associated with the penetration of new technologies (e.g., first costs versus nth-of-a-kind costs, and learning curves). Where possible the methodologies used in the models described will be incorporated in the ECP.

The following sections examine how each model manages capacity expansion decisions based on demand-side management programs, non-utility generators, renewable technologies, advanced technologies, life extension/refurbishment, environmental compliance, time periods, regions, solution techniques and data requirements.

3.3.1 FOSSIL2

FOSSIL2, the integrating analysis tool used for the National Energy Strategy, is a dynamic simulation model which forecasts long term (30 to 40 years) behavior of the U.S. energy system. The model is an equilibrium energy market model in which energy markets "clear" over time as a result of feedback among prices, demand, and production capacity. FOSSIL2 uses a system dynamics methodology, based on modern control theory, by which system behavior is represented using differential and integrating equations. FOSSIL2 is written in the PC-Dynamo computer language.

FOSSIL2 addresses demand-side management considerations explicitly as end-use "conservation" technologies. These technologies are represented in "supply" curves that plot cumulative savings (percent) against capital costs (\$/Million Btu) for each end use and fuel type. The model computes whether capital invested in the conservation technology has a projected payback period in the range of 2 to 5 years. The technologies are arrayed in a least-cost order on the curve and the cheapest measures are implemented first. The model also allows simulation of electric utility investments in end-use conservation.

An Electricity Generation Sector contained in the model extrapolates historic load growths forward over a horizon of five to seven years and divides the projected load into peaking and combined intermediate/base

components to assess forecasted generation requirements.²⁶ By comparing these requirements to existing resources (less expected retirements) and resources under construction, new capacity needs over the horizon are estimated. Using cost and performance data from 23 types of utility generators and 11 types of non-utility generators, the projected cost per kilowatthour is calculated for each point in time from capital costs, fuel costs, and non-fuel operating costs. By comparing each non-regulated utility supplier's (NUGS) levelized costs to the utility's avoided costs, a least-cost combination of nonutility technologies is selected to fill the non-utilities market share. Utilities technologies supply the remaining capacity requirements.

User-defined parameters are used to extend the lives of oil, gas, and coal-steam plants slated for retirement. Part of the remaining coal plants can be repowered by implementing atmospheric fluidized bed and integrated gasification combined cycle technologies. Coal gasification for gas combined cycle, steam injected gas turbines, and natural gas fuel cells is selected when this option becomes economically attractive.

Demand is split into base, intermediate, and peaking load requirements using an annualized load-duration curve. Base load is satisfied by nuclear and some renewable technologies (including geothermal and biomass) followed by part of coal and oil/gas capacity specified as base-load. Although not explicitly stated in the documentation, a graphical representation of a load curve shows that base nuclear, renewable, coal, and oil/gas generation occupy the region of the curve extending from the base to the knee. Intermediate load is supplied by intermediate renewable (solar, wind) and the remaining coal and oil/gas capacity which is dispatched on a relative operating cost basis. Peak capacity requirements are filled by combustion turbines, storage, photovoltaic, and solar thermal technologies. The resulting capacity factors are then used to calculate operating costs for use in ratemaking calculations.

The user can choose several policy options. All cost and performance data is user-specified. Furthermore, the user can designate limits on expenditures for conservation measures, the percentage of utilities which participate in these programs, and whether the utility expenses these costs or puts them into the ratebase.

Renewable energy sources are represented in FOSSIL2 in two groups: those which are located at the user's facility (dispersed), and those used to generate electricity for a utility. Utility renewable generation is represented in the electricity sector while dispersed renewable are handled by the demand sector. Each group is further sub-divided into utility and non-utility clusters. In FOSSIL2, renewable technologies compete with conventional base and intermediate load technologies using the same least-cost approach described above for non-utility generation. Photovoltaic and solar thermal technologies are allowed to compete with combustion turbines for a limited share of peaking capacity. Renewable technologies including solar and wind technologies, which are assumed to have gas turbine backups providing up to 25 percent of the facility's total output, are allowed to operate at their full availability. Utility hydropower, pumped storage and non-utility municipal wastes are treated exogenously; however, non-utility small hydro is competed with other technologies for market share.

Carbon, methane, nitrogen oxide (NO_x), and SO_2 emissions associated with end-use consumption and conversion activities are computed by FOSSIL2 using separate emission coefficients for each fuel. As policy options for meeting the Clean Air Act standards, the user can specify that utilities switch from high to low sulfur coal, retrofit coal plants with scrubbers, repower conventional coal plants with an advanced technology, increase efficiency of existing scrubbers, or purchase emission allowances. However, the model can not choose these options on an economic basis.

The model is regularly simulated from 1950 onward to validate its appropriateness for national energy policy analysis. It has been tested at extreme values (oil price shocks of 1973 and 1978) and with high carbon taxes. It has also been used in several studies conducted by the Energy Modeling Forum at Stanford University.

²⁶The peak load, which occurs for only a few hours during a year, is the maximum demand for electric power. The base load is the minimum load that exists continuously. Intermediate load refers to power demands between the base and peak loads.

3.3.2 AUSM/UPCODE

EPA's Advanced Utility Simulation Model (AUSM) is an emissions cost and forecast model composed of two sub-models: the National Loop Model and the State Model. The State model has been installed on a desk top computer (a Sun Workstation) and a Utility Planning and Coal Demand Module (UPCODE) has been designed to replace the multi-period, multi-state segment of the National Loop in order to facilitate installation of the Loop in the workstation environment.

UPCODE uses a multi-period LP methodology to calculate least-cost forecasts (over a 40-50 year period) of utility dispatch patterns, capacity expansion and coal selection decisions, and transmission levels subject to constraints on generation, equipment operation, transmission, and regional or state SO₂ emissions. The user must create 14 data files containing region selection, break years, types of emissions constraints, fuel prices, individual state demand levels and demand growth rates, coal prices, available capacity by region, load factors, escalation and discount rates, regional SO₂ limits, regional transfer limits, technology specific operations and maintenance costs, capacity factors and heat rates. Moreover, transfer costs, loss factors, and transfer limits between each state pair must be input as user-supplied data. These data files determine the coefficients of the objective function and constraint equations for each user-specified region.

AUSM/UPCODE does not explicitly address DSM programs, non-regulated utility competitors, or life extension/refurbishment capabilities. Also, the model does not explicitly differentiate between advanced and conventional technologies or renewable and non-renewable fuel technologies. For environmental compliance, the model minimizes costs subject to constraints on the maximum number of scrubber retrofits and state or regional user-specified SO₂ emissions limits.

3.3.3 PROSCREEN II

PROSCREEN II is an integrated planning model designed to support electric utility managers in the areas of decision analysis and corporate planning and is capable of reporting unit-by-unit generation statistics including unit emissions. The system consists of five modules that can be executed individually, in any combination, or globally as an integrated package: a Load Forecast Adjustment Module (LFA) which creates and modifies load forecasts and evaluates DSM options, a Generation and Fuel Module (GAF) which is essentially an electricity dispatching model, a Capital Expenditure and Recovery Module (CER) which computes the capital costs and financial ramifications attributed to capacity expansion, a Financial Reporting and Analysis Module (FIR) which constructs financial statements based on results obtained from the LFA, GAF, and CER modules, and PROVIEW which is a resource optimization module designed to determine the least cost supply and demand strategy to optimize utility resources. Of these five modules, only the LFA, CER, GAF and PROVIEW modules are relevant to requirements for the ECP Submodule of the EMM.

The LFA Model builds load forecasts from user-defined, end-use load groups based on hourly load shapes. If the data are unavailable for a particular load group, then the model allows the user to input such factors as the peak, energy, and coincidence factors of unknown groups. The LFA module will then approximate the requisite load shapes. It evaluates the impact of DSM programs on these groups. By ranking each individual DSM program on the basis of total cost, utility cost, and ratepayer impact, the module screens demand-side management programs to evaluate various cost effectiveness measures and works in unison with the PROVIEW model's optimization algorithm to modify load requirements. Calculations in the LFA are performed on a user-specified, seasonal basis. Additionally, estimates of net changes in seasonal demand, energy, and hourly customer load shapes can be used to measure the impact of direct end-use load control programs.

The CER Module compares and evaluates the economic impact of generation alternatives. While the CER module addresses many facets of the financial effects of construction alternatives (cash flows, depreciation, and tax credits to name a few), its function in examining the capital cost profiles of optimized expansion plans returned by the PROVIEW module allows the CER to create a user-selected data base which lists in-service dates for expansion units.

The GAF Module reports environmental emissions ranging from NO_x and SO₂ to CO₂ and particulates. The user must specify the pollution content of each fuel and also emission factors for each effluent at each generating unit. The dispatching order of emissions-affected units is modelled by incorporating an emissions penalty cost based on the cost of emissions removal or regulatory compliance or using the PROVIEW module to optimize compliance by adding scrubbers, shutting down units, or converting to use other fuels. The module accounts for uncertainty in year-to-year water conditions of hydro-based systems. Thermal production costs are probabilistically weighted for a user-specified number of "water years" to account for this uncertainty.

The PROVIEW module is a resource planning optimization model which computes the cost and reliability of adding new capacity to the system or modifying load through DSM programs. PROVIEW grants the user a choice of five objective functions to be used in the least cost optimization: minimize revenue requirements, minimize average study period rates, minimize customer class rates, and minimize societal costs, or to maximize consumer value. According to the documentation, the module also incorporates alternative technologies, unit conversions, cogeneration, independent power producers, marketing and conservation programs, emissions trading and environmental policy options as parameters in determining least-cost strategies.

3.3.4 EGUMS

The Electric and Gas Utility Modeling System (EGUMS) is an integrated environmental assessment model which projects (1) demand for electricity and natural gas in the industrial, commercial, and residential sectors, (2) technical, economic, and achievable levels of improved end-use efficiency, and (3) changes in greenhouse gas emissions due to changes in end-use demand levels. Examining only U.S. territory in NERC regions, the model assesses regional energy consumption and emissions levels for the near term in increments of five years from 1990 through 2010.

Using EIA consumption surveys to calculate base-year electric and gas consumption in nine NERC regions, the simulation incorporates EPRI end-use demand models to forecast demand for energy services in the residential, commercial, and industrial sectors. By compiling energy conservation measures by sector for each end-use, the impact of alternative combinations of purchased electricity and natural gas and purchases of advanced end-use technologies on demand is examined to ascertain estimates of energy savings, coincident demand capacity savings, technical and physical applicability, usable lifetime of the energy conservation measures and the capital costs of effecting these measures.

The maximum savings achievable through immediate implementation of all commercially available technologies that provide increased levels of energy service, termed the technical potential for savings, is then translated into a more realistic representation of the underlying economic and market constraints that affect penetration of these technologies. The energy savings resulting from these scenarios are then translated into avoided carbon emissions for each fuel type in the region.

The model consists of five modules: (1) an Energy Use Database that determines base-year consumption of electricity and natural gas by region, sector, segment and end-use, (2) an End-Use Sector Model that forecasts a "no-conservation" scenario using EPRI's models, (3) an Energy Conservation Measures Model (ECM) that estimates the technical potential savings of demand-side measures, (4) a Regional End-Use Savings Model that translates the technical potential into cost-effective ("economic") potential and likely ("market achievable") energy savings and (5) a Carbon Emissions Model that converts the energy savings into avoided carbon emissions. This division tends to enhance modular flexibility.

Additionally, the model assesses the growth of unregulated energy service companies, appliance standards and building codes, subsidies and rates of product promotion for energy efficient end-use appliances, and utility sponsored demand-side management. EGUMS does not include advanced and speculative technologies nor does it explicitly address renewable technologies and life extension/refurbishment as supply-side conservation options.

3.3.5 EGEAS

The Electric Generation Expansion Analysis System (EGEAS) is a modular generation expansion package that enables utility planners to evaluate the caliber of least cost strategies, the influence of independent power producers on utility expansion, and alternatives regarding avoided costs and/or life extension scenarios. EGEAS is not an integrating model. The model enumerates the type, size, and installation date for each selected demand- and supply-side alternative. Furthermore, a PC version of the model contains a direct load control dispatching algorithm to expand measures involving demand-side alternatives.

EGEAS uses a demand-side workstation developed by Synergic Resources Corporation, to screen DSM programs to a more reasonable number and to pass the results to EGEAS for evaluation. The model then associates these programs with various supply-side alternatives to acquire a least-cost mix of options that satisfies reliability criteria. EGEAS uses two autonomous optimization programs—one developed at the Massachusetts Institute of Technology and the other developed by Stone and Webster Management Consultants, Inc.—to develop LP and dynamic programming solutions, respectively. Additionally, the model's design can incorporate Generalized Bender's Decomposition (an efficient method that partitions large, multidivisional problems into a series of smaller subproblems that are solved), Year-End Optimization, and Specified Expansion Pathway Analysis Optimization algorithms to appropriately model fractional and multiple capacity expansions and to execute sub-yearly production costing analysis.

The model can use hourly load values which it converts to annual load duration curves. An Edit program constructs a data base containing the rated, reserve, emergency, and operating capacities for each generating unit. Also required are forced outage rates, maintenance rates, heat rates, and storage efficiencies.

EGEAS also possesses the unique capability to model the impact of non-dispatchable Technologies (NDT) like run-of-river hydro, cogeneration, solar, customer-owned, and photovoltaic generation on conventional production cost and system reliability. The model employs a stochastic algorithm which describes the association between customer load and NDT generation and positions this generation as a decision variable in capacity expansion calculations. Moreover, EGEAS efficiently addresses fuel savings and reliability issues affiliated with storage technologies by representing operational decisions in two distinct domains: generation and charging as opposed to storage level capacity.

EGEAS has the ability to model environmental consequences of capacity expansion. User-defined limits on the annual amounts of fuel burned can be utilized by the linear programming package to impose emissions and land usage constraints on system expansion. The model calculates the amounts of emissions based on two classes: input and output emissions. Input emissions, such as SO_2 and NO_x , are defined as those contaminants released to the environment by fuel consumption. Output class emissions refer to environmental effects not directly related to fuel consumption such as cooling water consumption and output heat that warms a body of water. For each class and type of emissions, user-supplied fuel types and emission production rates are required to evaluate the amount of emissions produced by each plant. Since the production rate indicates which percentage of the fuel is released to the environment, these rates indicate which method of pollution control, if any, the generating unit will use.

The model does not address regional divisions; however, EGEAS does provide for system interconnections by allowing the user to specify two systems (A or B) to model power exchanges and adjust for tie-line capacity limits.

EGEAS contains a Describing Function Program (DESFUN) as a post processor to examine the results of optional sensitivity analysis reports. The user designates which variables are to be perturbed and DESFUN relates the magnitude of variation to user-specified polynomial functions using a weighted least-squares algorithm. The resultant describing functions are used for trade-off and uncertainty analysis external to EGEAS.

The system's analysis options have been tested using three different data sets: two data sets adopted from an EPRI synthetic utility system and another constructed from data concerning existing and committed generating units supplied by Pacific Gas and Electric. The model claims good correlation between the Generalized Bender's Decomposition and Dynamic Programming options with respect to yearly production costing analysis excluding integer versus capacity additions in the optimal solution. Because the Dynamic Programming and Specified Expansion Pathway Analysis Optimization options can execute sub-yearly calculations, they are professed to be preferable to the LP and Generalized Bender's Decomposition methods regarding storage, hydro, and maintenance scheduling evolutions. Although strong in the areas of modeling simplicity and computational efficiency, the Linear Programming option was found to be inferior to that of the Generalized Bender's Decomposition and Dynamic Programming methods. However, the LP option is considered the method of choice for preliminary system analysis.

3.3.6 ARGUS

The ARGUS Model is a dynamic integrated utility system representation of the economic, environmental, and technological concerns influencing energy policy issues and emission control strategies. The model contains four distinct components that model individual facets of the utility sector: the Build Cost Module (BCM) which satisfies future demand by adding new units or repowering old units; the ICARUS module which effects unit dispatching and performs related production-cost analysis; the Emissions and Control Module (ECM) which calculates quantities of emissions and the costs of implementing emission control strategies and regulations; and the Coal Supply and Transportation Module (CSTM) which forecasts delivered coal prices. Each module has the ability to function as a stand-alone unit.

Using target reserve margins, projected growth rates for peak demand, and amounts of existing and planned capacity on line for a given year, BCM employs a least-cost strategy to increase capacity by building new units or repowering existing units. BCM divides the forecast period into three exclusive periods: near-term (approximately 10 years), mid-term (user-specified, typically an additional 10 years), and long term (ARGUS specified period of 25 years). The module does not add unplanned capacity during the near-term period. If, at the end of the near-term period, capacity is below the sum of the expected peak and the target reserve margin, then BCM phases in new capacity over a user-specified mid-term period until capacity requirements are satisfied. During the long-term period, new capacity is added to maintain the target reserve margin.

Preference is given to repowering over new construction to meet capacity specifications. User-specified inputs (vintage, variable costs, and emissions of units) can be used to determine the order by which units are repowered. Any group of electricity generating units constitutes a system; however, the model normally uses 33 power-pool systems which are each sub-divided into state and coal-supply transportation regions. If system-wide capacity goals are not achieved, then new units are built based on exogenous or endogenous build mixes. The user can exogenously assign a percentage based build mix. BCM will then assign pollution control options on a least-cost basis to each type of unit to be constructed. The module also ascertains the type of fuel and flue gas desulfurization (FGD) technology for coal units. In the endogenous procedure, BCM calculates system-wide fuel costs and costs of emissions options. The model selects the least-cost option for construction, adding one unit at a time to the system, by displacing units with lower loading-order numbers (typically equal to the variable cost) on an Annual Equivalent Load Duration Curve (ELDC).

ICARUS is a probabilistic dispatching model that assigns capacity factors to electricity generating units using a convolution process, which calculates a cumulative probability curve for each unit by combining two separate curves--one that assumes constant availability for the unit and another that assumes constant unavailability. Data sent from ICARUS are used by BCM to decide which types and numbers of new units to add to fulfill reserve margins. The module explicitly accounts for routine maintenance outages, net electricity imports or sales, monthly system load factors, and the effect unit failures have on unit assignments, fuel use and generating costs.

ECM computes the cost of emission control strategies and regulations in addition to the amounts of SO₂, NO_x, CO₂, and particulate emissions generated in the electric utility sector. Control strategies considered by the module include unit level limits on emission rates, emissions trading, economic incentives and least-emissions dispatching.

Based on volume of coal, supply region, and transportation route, CSTM forecasts delivered coal prices. CSTM depicts the coal supply using an exogenous set of demand curves from the Resource Allocation and Mine Costing Model (RAMC).²⁷

ARGUS uses a unit inventory data base containing information on each electricity generating unit in the continental U.S. Unit characteristics stored in this file include fuel prices, fuel quality, fuel origin, and operational characteristics regarding heat rates, plant maintenance rates, forced outage rates, and pollution control equipment. The data base is modified through each step of the simulation.

The model does not address advanced technologies or DSM incentive programs. Furthermore, ARGUS does not explicitly differentiate between investor-owned utilities and non-utility generators.

3.3.7 OVER/UNDER

OVER/UNDER is a capacity planning model which can be used to study the projected costs and benefits of alternative planning reserve margins in an environment of uncertain demand. This demand uncertainty is addressed by using decision trees to trace out the costs and benefits enumerated by each alternative expansion scenario. The model compares the cost of overplanning capacity against the probability of generation deficiencies as a result of underplanning to calculate the total cost of alternative capacity additions for consumers and shareholders.

Using probability trees, the model simulates demand over 20 to 30 years with each level of branching in the tree representing one or more years and constituting a "period." At the conclusion of the planning horizon, the model calculates capacity additions, production costing, and financial estimates over a user specified "terminal horizon". Demand uncertainty is input to the model by constructing cumulative probability curves based on direct or indirect assessment methods. Direct assessment entails judgmental factors supplied by experts in electricity demand whereas indirect assessment exploits computer analysis of structurally related variables and historical data affecting demand. The probability curves are transformed into demand probability trees with branches representing high, medium, or low demand effects. The number of branches grows exponentially based on the number of branch nodes and periods.

OVER/UNDER makes capacity decisions by examining the planning process from three perspectives: initial planning and studies; licensing; and construction and startup. Commitments to each stage are justified only when compelled by power need expectations based on the demand probability tree. Capacity types are selected based on a desired long-run mix of technologies, technological availability, and lead time constraints. Once peak demand, load shapes, and installed plants are specified for a tree path, a probabilistic simulation algorithm determines the expected energy generated yearly by each plant, the cost of system generation, and the amounts of forced outages (energy demand not served). The model can represent variations in hydroelectric generation in terms of wet, dry, and normal weather conditions.

OVER/UNDER computes system environmental costs for each technology as the product of its expected energy generation and a user-supplied environmental charge rate that increases at the rate of inflation. The model does not address non-utility generators or life extension/repowering options. The model requires detailed system data regarding peak demand, demand growth probability curves obtained from external probability encoding techniques, target technology mix, load time for new additions, and unit sizes.

3.3.8 Summary

²⁷For more information, see Energy Information Administration, *Documentation of the Resource Allocation and Mine Costing Model*, DOE/EIA-M021 (Washington, CD, May 1987).

None of the models reviewed achieve all of the current requirements of the ECP module. Three models (EGEAS, ARGUS, and OVER/UNDER) do not include integral fuel supply and demand components. EGUMS, while being an aggregate model, is primarily an environmental assessment model concerned with the impact of energy conservation measures on future carbon emissions. PROSCREEN II, OVER/UNDER and AUSM/UPCODE are utility or regional planning models designed to represent the operations of individual utilities or power pools. Consequently, they require detailed user-specified and utility-specific data based on narrowly defined clusters such as customer class, end-user group, or user-defined state and local regions. Finally, although FOSSIL2 computes carbon, methane, NO_x, and SO₂ emissions under different policy options, the model does not evaluate emissions reductions options on an economic basis. However, if alternative models are modified to incorporate the proper linkages with the other components of the NEMS, the modular design of the system will allow the flexibility to substitute them.

4. MODEL STRUCTURE

4.1 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 supply-side and demand-side 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 30-year 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, implementing DSM programs, 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.

Section 4.2 summarizes the sequence of operations in the ECP, focusing on the primary routines that revise the coefficients of the LP model. Section 4.3 provides a mathematical description of the LP model and specifies the objective function and equations of the constraint matrix. The equations that derive the revised coefficients for the LP model are described in greater detail in Appendix B. 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 briefly described in Appendix C, but are not documented in this report.²⁸

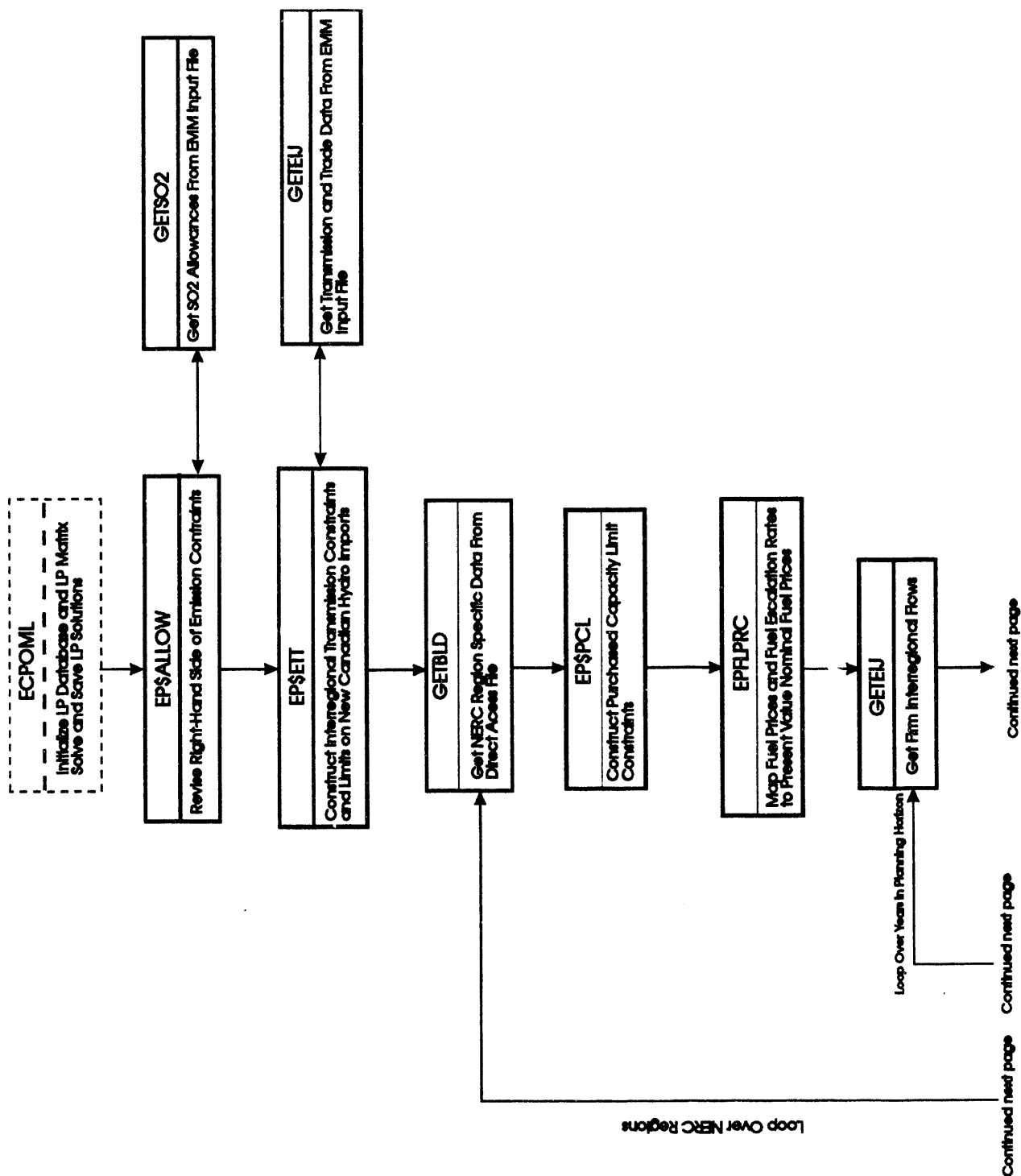
4.2 Flow Diagram

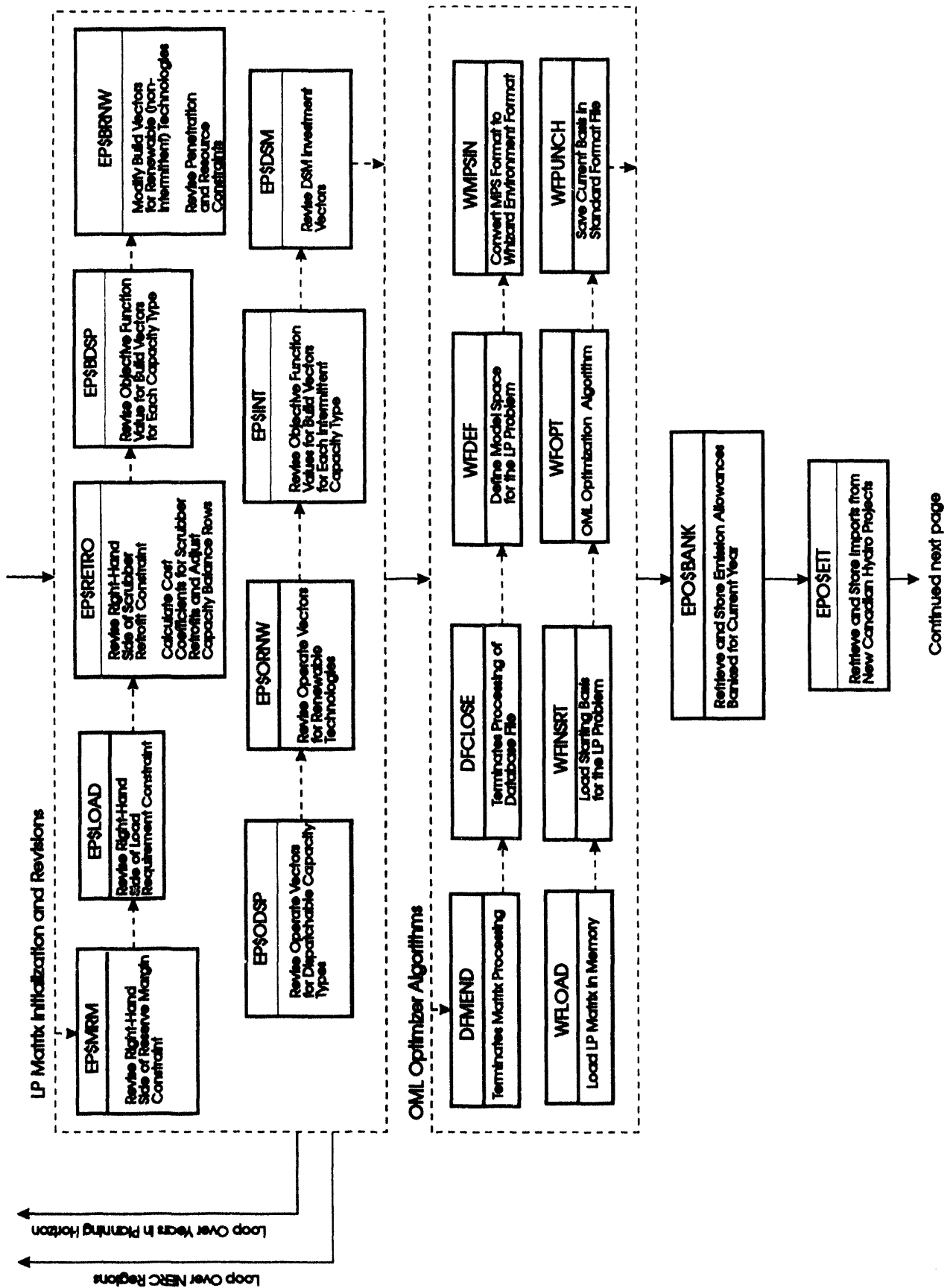
The EMM is modular and can be executed with or without the ECP. A user-specified switch, `USW_ECP`, controls the execution of the ECP. The subroutine *ELECP* initializes variables and checks the value of `USW_ECP`. If the ECP is turned off, then the EMM uses the capacity planning decisions from a previous 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 (Figure 3). 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.

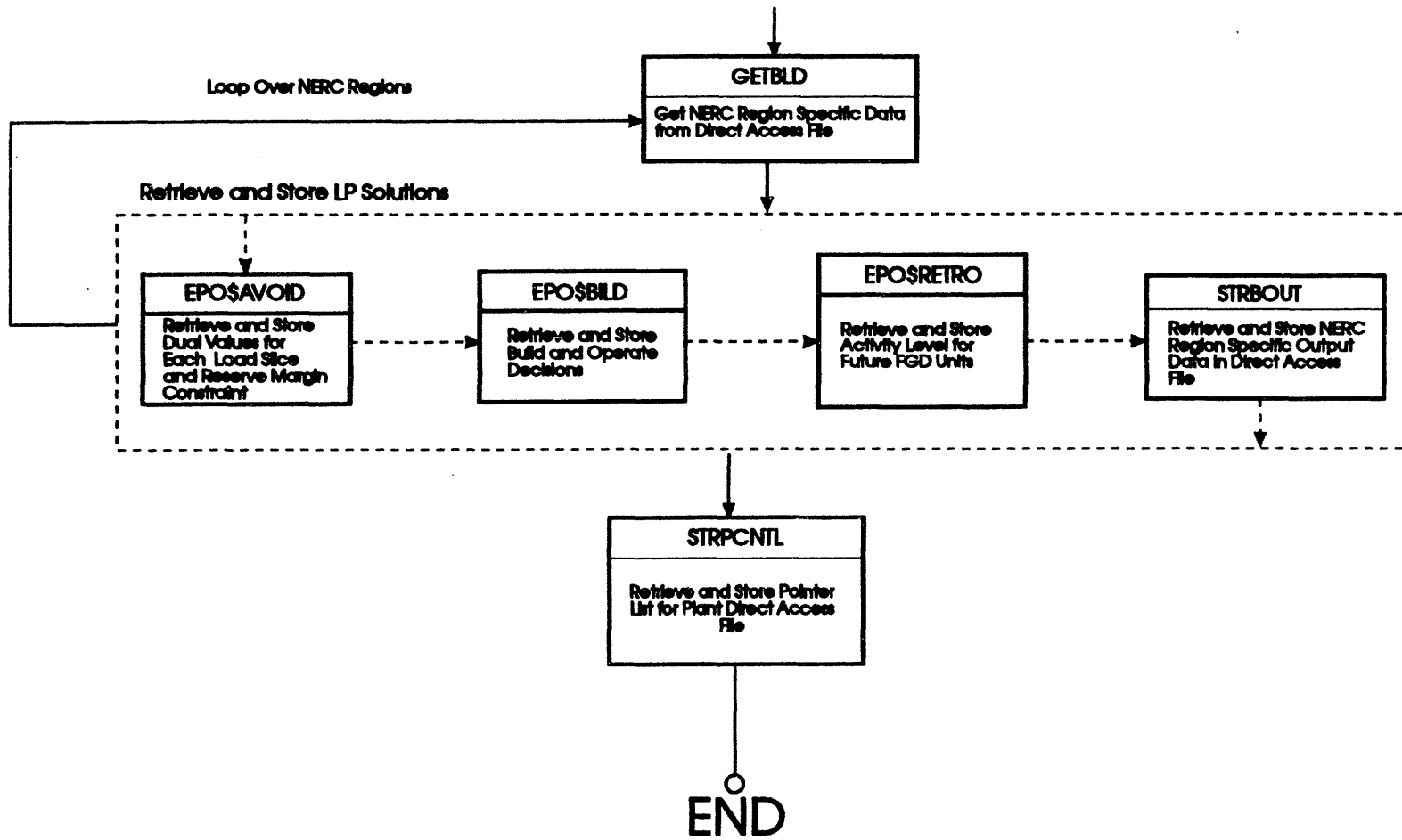
ECPOML calls *EP\$ALLOW*, which sets up the right-hand side of the emissions constraints for each year of the planning horizon (Figure 3). For SO_2 , the right-hand side represents the limit corresponding to the sum of the emissions allowances allocated in accordance with the Clean Air Act Amendments of 1991. Restrictions on SO_2 emissions are implemented as national constraints since allowances can be traded. If emissions allowances have been banked by overcomplying in previous years (i.e., emitting less sulfur

²⁸For more information, see Ketron Management Science, *Optimization and Modeling Library (Draft)*, (Arlington, VA, November 1992).

Figure 4. Flow Diagram for the Electricity Capacity Planning Submodule







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 SO₂ 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.²⁹ 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 *EP\$FLPRC*. *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. *EP\$FLPRC* 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.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 (Section 4.3).

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.³¹ *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.

²⁹Some 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".

³⁰The 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.

³¹Revenue 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\$ODSP modifies the coefficients for decision variables that describe the allocation of fossil-fuel and nuclear to meet the demand for electricity (referred to as "operate vectors"). It determines the cost of operating fossil-fuel and nuclear capacity types, based on the discounted, present value of operating expenses (fuel and variable operating and maintenance costs). These capacity types are considered "dispatchable" since they are generally available to generate electricity except for planned and unplanned outages. One of the decisions evaluated by the ECP is the mode of operation for these capacity types, which ranges from "baseload" (continuous operation except for outages) to "peaking" (operated only during periods when demand is high). The total variable cost depends on the utilization rate and the per-unit operating costs. *EP\$ODSP* calls *EPDRATE*, which calculates the derating factors for dispatchable capacity types across all load slices. The derating factor is a function of the forced outage rate, planned maintenance rate, and load following rate of the capacity type and of the load shape.

EP\$ORNW is similar to *EP\$ODSP* except it determines the operating cost and performance coefficients for renewable capacity types, excluding intermittent technologies. If appropriate, the variable costs for renewable technologies are reduced to account for subsidies specified in EPACT. The renewable capacity types described in *EP\$ORNW* are similar to fossil-fuel and nuclear units in that they are generally dispatchable but they may be subject to an energy constraint (e.g., steam for geothermal and water for hydroelectric) that imposes a maximum utilization rate.

EP\$INT revises the cost and performance coefficients for intermittent technologies. Unlike the dispatchable capacity types, which have separate decision variables for the construction and operation on capacity, a single variable is used for intermittent technologies. The ECP essentially determines whether or not to build these capacity types because they will be operated if available since they have relatively low operating costs. However, the utilization of these technologies varies according to the season and time-of-day depending on the availability of the resource (e.g., sun and wind). The objective function coefficient is the present value of building and operating intermittent technologies. As with the other renewable technologies, the capital and operating costs are decreased to reflect subsidies from EPACT. The coefficients in the constraint matrix describe the variations in utilization rates across the seasonal and time-of-day load segments.

EP\$DSM is designed to modify the coefficients for decision variables that describe investments in DSM programs.³² 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 (Figure 3). *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

³²The data to modify the coefficients will be provided by the Load and Demand-Side Management Submodule when the linkages are completed.

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.

4.3 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., overcomplying in a particular year and saving the allowances for future use). The LP model determines the appropriate mix of supply and demand 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 22 load slices and the minimum reserve margin requirement. Dispatchable capacity types (e.g., fossil-fuel, nuclear, and nonintermittent renewable technologies) can satisfy capacity and energy requirements for any or all of the load segments. Their utilization depends primarily on their availability, fuel constraints (if any), and the relative economics of the potential options. A baseload generating plant type is used in all of the load categories, whereas a peaking plant type is allocated to the first few segments (Figure 3). 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 (and DSM programs when they are added to the model) 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 30-year, 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 30-year period. Similarly, operating costs are determined for 30 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 next 25 years.

The structure of the ECP is described below.

4.3.1 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)
- n = Next Year In Planning Horizon
- p = Previous Year In Planning Horizon
- r = Electricity Supply Region
- e = Export Electricity Supply Region
- g = Import Electricity 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
o	=	Owner (Utility or Non-Utility)
u	=	Retrofit Cluster Code
s	=	Canadian Import Supply Step

4.3.2 Decision Variables

EXC_{yrc}	=	Utilize Existing Dispatchable Capacity Type c in Year y in Region r (Gigawatts)
EXR_{ym}	=	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_{yrcfm}	=	Allocate Dispatchable Capacity Type c Consuming Fuel f in Mode m in Year y in Region r (Gigawatts)
OPR_{ymn}	=	Allocate Renewable Capacity Type n in Year y in Region r in Mode m (Gigawatts)
OPH_{yrl}	=	Allocate Hydro Capacity in Vertical Load Step l in Year y in Region r (Gigawatts)
BLD_{yrco}	=	Build New Dispatchable Capacity Type c by Owner Type o Beginning Operation in Year y in Region r (Gigawatts)
RNW_{ymn}	=	Build New Renewable Capacity Type n by Owner Type o Beginning Operation in Year y in Region r (Gigawatts)
INT_{yrio}	=	Allocate/Build Intermittent Renewable Type i for Owner Type o Beginning Operation in Year y in Region r (Gigawatts)
DSM_{yrd}	=	Implement Demand-Side Management Technology d Starting in Year y in Region r (Gigawatt Equivalent)
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_{yn}	=	Bank Allowances for SO ₂ From Year y to the Next Year n (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_{yerc}	=	Dispatchable Capacity Type c Transferred from Export Region e to Import Region r in Year y (Gigawatts)
BDI_{yerc}	=	Build Dispatchable Capacity Type c by Owner Type o in Export Region e for Import Region r in Year y (Gigawatts)
BRI_{yenr}	=	Build Renewable Capacity Type n by Owner Type o in region e for region r in Year y (Gigawatts)
BII_{yeir}	=	Build Intermittent Capacity Type i by Owner Type o in region e for region r in Year y (Gigawatts)
BCH_{yrs}	=	Build Canadian Hydro Capacity in Canadian Import Supply Step s for Region r in Year y (Gigawatts)

For dispatchable technologies, separate variables are 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 proposed formulation does not explicitly represent intermittent technologies coupled with a back-up source of power, but it will effectively determine 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.

4.3.3 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)
$DSML_{dr}$	=	Demand-Side Management Technology Limits for DSM d and Region r. (Gigawatt Equivalent)
$INTL_{ir}$	=	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)
$FGDL_{cru}$	=	Retrofit Limit for Unscrubbed Capacity c and region r (Gigawatts)
$EBITX_{yr}$	=	Earnings Before Interest and Taxes from Existing Ratebase (Million Dollars)
$INTEXP_{yr}$	=	Interest Expenses from Existing Commitments plus Existing Purchased Capacity Payments (Million Dollars)
$TICR$	=	Target Interest Coverage Ratio (Scalar)

4.3.4 Coefficients

ELA_{yrcfm}	=	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_{ymlm}	=	Derating Factor (Adjustment for Forced Outage, Planned Maintenance, Load Following Rates and Availability of Resource) for Renewable Capacity Allocated to Meet Capacity Requirements In Load Step l In Year y, Region r By Capacity Type n in Mode m (Fraction)
ELI_{yri}	=	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)
$ELCH_{yrsi}$	=	Derating Factor (Availability of Resource) for Imported Canadian Hydro Step s in Load Step l In Region r 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_{ym}	=	Contribution Made to Satisfying the Reserve Margin Made By Renewable Capacity Build Type n Beginning Operation In Year y for Region r (Fraction)

ELD_{yzrdl}	=	Amount of Capacity Requirement Eliminated or Created In Load Step l In Year z By Demand Side Technology d Initiated In Year y, Region r (Fraction)
RMD_{yzrd}	=	Contribution Made In Year z to Satisfying the Reserve Margin Made By Demand Side Management Technology d Started In Year y for Region r (Fraction, 0.0 = Option Never Available at Peak, 1.0 = Option is Always Available at Peak)
$SO2_{yrctfm}$	=	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 (Millions of Tons / Gigawatt)
$TLOSS_{yer}$	=	1 - Interregional Transmission Loss Factor from region e to region r in Year y (Fraction)
$COPD_{yrctfm}$	=	Variable Operating Cost Including Expected Fuel Costs to Operate Dispatchable Capacity Type c Using Fuel f In Mode m for Year y and Region r (Million Dollars / Gigawatt)
$COPR_{ym}$	=	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)
$CBLD_{yrco}$	=	Investment Cost to Build Capacity Type c by Owner Type o With Initial Online Year y in Region r (Millions of Dollars / Gigawatt)
$CRNW_{ymo}$	=	Investment Cost to Build Renewable Capacity Type n by Owner Type o With Initial Online Year y in Region r (Millions of Dollars / Gigawatt)
$CBDI_{yecro}$	=	Investment Cost to Build Dispatchable Capacity Type c by Owner Type o With Initial Online Year y in Region e for Region r (Millions of Dollars / Gigawatt)
$CBRI_{yenro}$	=	Investment Cost to Build Renewable Capacity Type n by Owner Type o With Initial Online Year y in Region e for Region r (Millions of Dollars / Gigawatt)
$CINT_{yrio}$	=	Investment and Operating Cost to Build/Operate Intermittent Technology i by Owner Type o Starting Operation In Year y and Region r (Millions of Dollars / Gigawatt)
$CBII_{yeiro}$	=	Investment and Operating Cost to Build/Operate Intermittent Technology i for Owner o Starting Operation In Year y in Region e for Region r (Millions of Dollars / Gigawatt)
$CBCH_{yrs}$	=	Investment Cost to Build Canadian Hydro Capacity for Region r in Canadian Import Supply Step s With Initial Online Year y (Millions of Dollars / Gigawatt)
$CDSM_{yrd}$	=	Total Investment Cost of Demand Side Management Technology d Starting In Year y for Region r (Millions of Dollars / Gigawatt Equivalent)
$CFGD_{yrcku}$	=	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)
$PPCD_{yrjc}$	=	Incremental Purchased Power Costs in Year j for Dispatchable Capacity Type c, Built in Year y for Region r (Millions of Dollars / Gigawatt)
$PPCR_{yrjn}$	=	Incremental Purchased Power Costs in Year j for Renewable Capacity Type n, Built in Year y for Region r (Millions of Dollars / Gigawatt)
$PPCI_{yrji}$	=	Incremental Purchased Power Costs in Year j for Intermittent Capacity Type i, Built in Year y for Region r (Millions of Dollars / Gigawatt)
$PPCC_{yrs}$	=	Incremental Purchased Power Costs for Canadian Hydroelectric Power Step s in Year y for Region r (Millions of Dollars / Gigawatt)
$EBITD_{yrjc}$	=	Incremental Earnings Before Interest and Taxes in Year j for Dispatchable Capacity Type c, Built in Year y for Region r (Millions of Dollars / Gigawatt)
$EBITR_{yrjn}$	=	Incremental Earnings Before Interest and Taxes in Year j for Renewable Capacity Type n, Built in Year y for Region r (Millions of Dollars / Gigawatt)
$EBITI_{yrji}$	=	Incremental Earnings Before Interest and Taxes in Year j for Intermittent Capacity Type i, Built in Year y for Region r (Millions of Dollars / Gigawatt)
$EBITF_{yrjcku}$	=	Incremental Earnings Before Interest and Taxes in Year j for Investment in Flue Gas Desulfurization for Capacity Type c Transforming it to Capacity Type k, Built in Year y for Region r (Millions of Dollars / Gigawatt)

The derivation of these coefficients is contained in Appendix B.

4.3.5 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

- o operation of dispatchable capacity types ($COPD_{yrcfm} \cdot OPD_{yrcfm}$)
- o operation of renewable capacity types ($COPR_{yrnm} \cdot OPR_{yrnm}$)
- o operation of hydro capacity ($COPH_{yrl} \cdot OPH_{yrl}$)
- o construction and operation of intermittent renewable technologies ($CINT_{yrlo} \cdot INT_{yrlo}$)
- o implementation of DSM programs ($CDSM_{yrd} \cdot DSM_{yrd}$)
- o installation of pollution control devices at existing units ($CFGD_{yrcku} \cdot FGD_{yrcku}$)
- o transfer of capacity between regions ($CTRN_{yecr} \cdot TRN_{yecr}$)
- o construction of new dispatchable capacity types ($CBLD_{yrco} \cdot BLD_{yrco}$)
- o construction of new dispatchable capacity types for another region ($CBDI_{yecro} \cdot BDI_{yecro}$)
- o construction of Canadian Hydro capacity for region ($CBCH_{yrs} \cdot BCH_{yrs}$)
- o construction of new intermittent capacity types for another region ($CBII_{yeiro} \cdot BII_{yeiro}$)
- o construction of new renewable capacity types ($CRNW_{yrno} \cdot RNW_{yrno}$)
- o construction of new renewable capacity types for another region ($CBRI_{yenro} \cdot BRI_{yenro}$)

The objective function is expressed as follows:

$$\begin{aligned}
 (1) \text{ MIN } & \sum_y \sum_r \sum_c \sum_m \sum_f COPD_{yrcfm} \cdot OPD_{yrcfm} + \sum_y \sum_r \sum_c COPR_{yrnm} \cdot OPR_{yrnm} + \sum_y \sum_r \sum_l COPH_{yrl} \cdot OPH_{yrl} + \\
 & \sum_y \sum_r \sum_i \sum_o CINT_{yrlo} \cdot INT_{yrlo} + \sum_y \sum_r \sum_d CDSM_{yrd} \cdot DSM_{yrd} + \sum_y \sum_r \sum_c \sum_k \sum_u CFGD_{yrcku} \cdot FGD_{yrcku} + \\
 & \sum_y \sum_e \sum_c \sum_r CTRN_{yecr} \cdot TRN_{yecr} + \sum_y \sum_r \sum_c \sum_o CBLD_{yrco} \cdot BLD_{yrco} + \sum_y \sum_e \sum_r \sum_c \sum_o CBDI_{yecro} \cdot BDI_{yecro} + \\
 & \sum_y \sum_r \sum_s CBCH_{yrs} \cdot BCH_{yrs} + \sum_y \sum_e \sum_i \sum_r \sum_o CBII_{yeiro} \cdot BII_{yeiro} + \sum_y \sum_r \sum_n \sum_o CRNW_{yrno} \cdot RNW_{yrno} + \\
 & \sum_y \sum_e \sum_n \sum_r \sum_o CBRI_{yenro} \cdot BRI_{yenro}
 \end{aligned}$$

4.3.6 Description of Constraints

Emissions

These constraints limit the emissions produced as a result of electricity generation. The equations below are described for SO_2 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 to 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_{yn}). 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.

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 OPR_{yrcfm} represents the allocation of generating capacity type c and fuel type f to mode of operation m . The coefficient $SO2_{yrcfm}$ 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 removal of emissions (if any) due to pollution control equipment. The product of the two terms gives the total emissions. A national level constraint is represented as follows:

$$(2) \sum_r \sum_c \sum_f \sum_m SO2_{yrcfm} \cdot OPD_{yrcfm} + BNK_{yn} - BNK_{py} \leq ALW_y$$

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:

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

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, will 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.

The ECP can also represent least-emissions dispatching by minimizing emissions rather than costs. In this case, the left-hand side of the emissions constraint would become the objective function. The original objective function would be represented as an accounting row in order to determine the associated cost. All other constraints would remain unchanged. The flexibility to minimize costs or emissions will be implemented as a user option.

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) and DSM technologies to the appropriate load segments while

maintaining the overall regional load characteristics. For each segment of the load duration curve, the capacity requirement (ELC_{yri}) 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_{yrcfm}) and the corresponding derating factor (ELA_{yrcfm}).

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_{ymm}) and the corresponding derate / capacity factor (ELR_{ymlm}). For hydroelectric plants, the capacity constraint is converted to an energy constraint and capacity utilization (OPH_{yri}) 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_{yero}) 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. Investment in DSM technologies (DSM_{yrd}) can satisfy (i.e., eliminate) capacity and energy requirements for selected load segments. Each DSM technology can have a different profile of load impact to investment, such as general conservation or peak shaving and valley filling. DSM programs that shift load requirements eliminate capacity and energy needs in one segment while creating additional needs in another segment. Finally, load can be met from the purchase of new Canadian hydroelectric power (BCH_{yrs}).

$$\begin{aligned}
 (4) \quad & \sum_c \sum_f \sum_m ELA_{yrcfm} \cdot OPD_{yrcfm} + \sum_n ELR_{ymlm} \cdot OPR_{ymmm} + \sum_i \sum_o \sum_{z=1}^y ELI_{zril} \cdot INT_{zrio} \\
 & + ELR_{ymlm} \cdot OPH_{yri} + \sum_i ELI_{yri} \cdot EXI_{yri} + / - \sum_d \sum_{z=1}^y ELD_{zyrdl} \cdot DSM_{yrd} \\
 & + \sum_i \sum_o \sum_e \sum_{z=1}^y ELI_{zril} \cdot TLOSS_{zer} \cdot BII_{zeiro} + \sum_s ELCH_{yrs1} \cdot BCH_{yrs} \geq ELC_{yri} \\
 & \text{for every load step } l \text{ in year } y \text{ and region } r.
 \end{aligned}$$

Capacity Balance Rows

For each capacity type, region, and year, the capacity balance equations limit production of electricity by the available generating capability. They are specified for all available conventional and advanced plant types. Utility and nonutility plants will be classified as different capacity types so that their respective contributions to electricity supply can be determined. New and existing units of the same plant type will be considered separate capacity types if warranted by differences in cost and performance characteristics. Units with and without scrubbers are also placed into separate categories because they have different costs and emission rates.

Each operate vector (OPD_{yrcfm}) 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 the cumulative new capacity (BLD_{yrc} or BDI_{yrcro}) that has been placed into service. The amount of

existing capacity is also affected by decisions to retrofit units and decisions to export or import exiting 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_{yrng}) have a positive term representing a use of native capacity. Imports (TRN_{yecn}) add to the available capacity with negative term. 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.

Dispatchable Capacity Balance Row

$$(5) \quad \sum_f \sum_m OPD_{yrfrm} - \sum_o \sum_{j=1}^y BLD_{jrco} + \sum_{j=1}^y FGD_{jrck} - \sum_{j=1}^y FGD_{jrkc} + \sum_g TRN_{yrng} - \sum_e TRN_{yecn} \cdot TLOSS_{yer} \\ - \sum_o \sum_e \sum_{j=1}^y BDI_{jetro} \cdot TLOSS_{jer} - EXC_{yrc} \leq 0.0$$

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

Renewable Capacity Balance Row

$$(6) \quad OPR_{yrnm} - \sum_o \sum_{j=1}^y RNW_{jrno} - \sum_o \sum_e \sum_{j=1}^y BRI_{jetro} \cdot TLOSS_{jer} + \sum_g TRN_{yrng} - \sum_e TRN_{yecn} \cdot TLOSS_{yer} - EXR_{yrn} \leq 0.0$$

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

Hydro Energy Balance Row

$$(7) \quad \sum_i OPH_{yri} \cdot ELR_{yri} - EXH_{yri} \leq 0.0$$

For every year y in region r.

Reserve Margin Requirement

The reserve margin constraints insure that the planning decisions that increase supply by adding new generating capability or reduce or shift demand by implementing demand-side management programs are sufficient to satisfy regional reliability requirements. Planning decisions will have to be implemented if the total capacity requirement (RMQ_{yr}) exceeds the existing capacity ($\sum_c EXC_{yrc} + \sum_n EXR_{yrn} + \sum_i EXI_{yri}$). 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_{yrco} , BDI_{yetro}), renewable (RNW_{jrno} , BRI_{jetro}) or intermittent (INT_{yrno} , BII_{yetro}). Alternatively, the need for additional capacity can be offset by DSM programs. For an intermittent technology, its capacity credit (RMI_{yri}) will depend on its ability to provide electricity when the peak demand occurs. Similarly, the contribution for a given DSM program

(RMD_{jyrd}) will depend on its ability to reduce the peak load. In addition, the amount of capacity is affected by imports / exports (TRN_{yrcg} / TRN_{yecn}) and by Canadian hydroelectric imports (BCH_{yrs})

The reserve margin constraint is formulated as follows:

$$(8) \quad \sum_c \sum_o \sum_{j=1}^y BLD_{jrc} + \sum_i \sum_o \sum_{j=1}^y INT_{jrio} \cdot RMI_{jri} + \sum_n \sum_o \sum_{j=1}^y RMR_{jrn} \cdot RNW_{jrno} + \sum_d \sum_{j=1}^y RMD_{jyrd} \cdot DSM_{yrd} \\ + / - \sum_c \sum_k \sum_u \sum_{j=1}^y FGD_{jrcku} + \sum_c \sum_o \sum_e \sum_{j=1}^y BDI_{jecro} \cdot TLOSS_{jer} + \sum_n \sum_o \sum_e \sum_{j=1}^y RMR_{jrn} \cdot TLOSS_{jer} \cdot BRI_{jenro} \\ + \sum_i \sum_o \sum_e \sum_{j=1}^y BII_{jeiro} \cdot TLOSS_{jer} \cdot RMI_{jri} + \sum_c EXC_{yrc} + \sum_n EXR_{ymn} \cdot RMR_{ymn} + \sum_i EXI_{yri} \cdot RMI_{yri} \\ + \sum_s \sum_{j=1}^y BCH_{jrs} \cdot RMR_{jrn} + \sum_g TRN_{ymg} - \sum_e TRN_{yecn} \cdot TLOSS_{yer} \geq RMQ_{yr}$$

For every year y and region r.

Purchased Capacity Constraint

The purchased capacity constraint is designed to establish an appropriate balance between purchased capacity and utility owned capacity. There are two basic concepts behind the formulation of this constraint. First, purchased power payments are considered to be the equivalent of debt. Like debt, purchased power payments limit the financial flexibility of utilities and tend to diminish the utilities attractiveness to investors. Second, the interest coverage ratio is the measure chosen to quantify the financial acceptability of the mix between purchased power and utility owned capacity. The interest coverage ratio is defined as the earnings before interest and taxes divided by interest expenses. In the model structure the interest coverage ratio has been modified to include purchase power payments as debt and a minimum target ratio is specified.

Calculation of earnings before taxes, interest and purchased power payments come from three basic sources within the model structure. First, earnings from the existing ratebase ($EBITX_{yr}$) are input to the ECP for each year y and region r. Second, revenues required to pay for new purchased power contracts are a function of the unplanned non-utility builds (ownership type o = N) and contracts for power from new Canadian hydroelectric projects determined by the ECP. The new purchased power payments are expressed as:

$$(9) \quad \sum_c \sum_{j=1}^y PPCD_{yrjc} \cdot BLD_{jrc(o=N)} + \sum_n \sum_{j=1}^y PPCR_{yrjn} \cdot RNW_{jrn(o=N)} + \sum_i \sum_{j=1}^y PPCL_{yrji} \cdot INT_{jri(o=N)} \\ + \sum_s PPCC_{yrs} \cdot BCH_{yrs}$$

For every year y and region r.

Third, the earnings generated from new utility investments (Ownership type o = U) are a function of the utility generation capacity additions and investment in new FGD units determined by the ECP. These contributions to earnings from unplanned utility additions are expressed as:

$$(10) \quad \sum_c \sum_{j=1}^y EBITD_{yrjc} \cdot BLD_{jrc(o=U)} + \sum_n \sum_{j=1}^y EBITR_{yrjn} \cdot RNW_{jrn(o=U)} + \sum_i \sum_{j=1}^y EBITI_{yrji} \cdot INT_{jri(o=U)} \\ + \sum_c \sum_k \sum_u \sum_{j=1}^y EBITF_{yrjcku} \cdot FGD_{jrcku}$$

For every year y and region r.

Interest expense is a combination of interest expense from existing sources ($INTEXP_{yr}$) and the new purchased power costs as defined above. The ratio of earned income to interest expense is required to meet or exceed a target interest coverage ratio (TICR) for all regions r and years y . This results in the following equation:

$$(11) \quad \frac{\left(EBITX_{yr} + \sum_c \sum_{j=1}^y PPCD_{yrjc} \cdot BLD_{jrc(o=N)} + \sum_n \sum_{j=1}^y PPCR_{yrjn} \cdot RNW_{jrn(o=N)} \right. \\ \left. + \sum_i \sum_{j=1}^y PPCI_{yrji} \cdot INT_{jri(o=N)} + \sum_s PPCC_{yrs} \cdot BCH_{yrs} + \sum_c \sum_{j=1}^y EBITD_{yrjc} \cdot BLD_{jrc(o=U)} \right. \\ \left. + \sum_n \sum_{j=1}^y EBITR_{yrjn} \cdot RNW_{jrn(o=U)} + \sum_i \sum_{j=1}^y EBITI_{yrji} \cdot INT_{jri(o=U)} + \sum_c \sum_k \sum_u \sum_{j=1}^y EBITF_{yrjcku} \cdot FGD_{jrcku} \right) \\ \left(INTEXP_{yr} + \sum_c \sum_{j=1}^y PPCD_{yrjc} \cdot BLD_{jrc(o=N)} + \sum_n \sum_{j=1}^y PPCR_{yrjn} \cdot RNW_{jrn(o=N)} \right. \\ \left. + \sum_i \sum_{j=1}^y PPCI_{yrji} \cdot INT_{jri(o=N)} + \sum_s EBITC_{yrs} \cdot BCH_{yrs} \right) \\ \geq TICR$$

For every year y and region r .

When this equation is restructured to place the model dependent computations on the left-hand side and the previously determined values on the right-hand side, this constraint appears as follows:

$$(12) \quad \sum_c \sum_{j=1}^y PPCD_{yrjc} \cdot BLD_{jrc(o=N)} + \sum_n \sum_{j=1}^y PPCR_{yrjn} \cdot RNW_{jrn(o=N)} + \sum_i \sum_{j=1}^y PPCI_{yrji} \cdot INT_{jri(o=N)} \\ + \sum_s PPCC_{yrs} \cdot BCH_{yrs} - \left(\sum_c \sum_{j=1}^y \frac{EBITD_{yrjc}}{TICR - 1.0} \right) \cdot BLD_{jrc(o=U)} \\ - \left(\sum_n \sum_{j=1}^y \frac{EBITR_{yrjn}}{TICR - 1.0} \right) \cdot RNW_{jrn(o=U)} - \left(\sum_i \sum_{j=1}^y \frac{EBITI_{yrji}}{TICR - 1.0} \right) \cdot INT_{jri(o=U)} \\ - \left(\sum_c \sum_k \sum_u \sum_{j=1}^y \frac{EBITF_{yrjcku}}{TICR - 1.0} \right) \cdot FGD_{jrcku} \\ \geq \frac{EBITX_{yr} - INTEXP_{yr}}{TICR - 1.0}$$

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.

$$(13) \quad \sum_c \sum_g TRN_{yrcg} \leq EXP_{yr}$$

For every year y and region r .

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.

$$(14) \quad \sum_c \sum_o \sum_{j=1}^y \text{BLD}_{jro} + \sum_c \sum_o \sum_e \sum_{j=1}^y \text{BDI}_{jcro} \cdot \text{TLOSS}_{jer} + \sum_s \text{BCH}_{yrs} \\ + \sum_n \sum_o \sum_{j=1}^y \text{RNW}_{jno} + \sum_n \sum_o \sum_e \sum_{j=1}^y \text{BRI}_{jenro} \cdot \text{TLOSS}_{jer} \\ \leq \text{MAX} (\text{RMQ}_{yr} - \sum_c \text{EXC}_{yrc} - \sum_n \text{EXR}_{ymn} , 0.0)$$

For every year y and region r.

Demand-Side Management Implementation Limit

Each DSM program can only be activated up to 100% penetration over all forecast year. Thus it can be constrained to less than 100% in one planning cycle if it has been partially selected in a previous planning cycle.

$$(15) \quad \sum_{j=1}^y \text{DSM}_{jrd} \leq \text{DSML}_{rd}$$

For every demand-side management technology d and region r.

Intermittent Build Limit

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

$$(16) \quad \sum_o \sum_{j=1}^y \text{INT}_{jro} + \sum_o \sum_e \sum_{j=1}^y \text{BII}_{jeiro} \leq \text{INTL}_{ir}$$

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.

$$(17) \quad \sum_o \sum_{j=1}^y \text{RNW}_{jno} + \sum_o \sum_e \sum_{j=1}^y \text{BRI}_{jenro} \leq \text{RNWL}_{nr}$$

For every renewable capacity type n and region r.

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 .

$$(18) \quad \sum_k \sum_{j=1}^y \text{FGD}_{jrcku} \leq \text{FGDL}_{cru}$$

For every unscrubbed capacity type c and cluster group u in region r .

Appendix A

INVENTORY OF DATA

This appendix provides a list of variables in the ECP. Each variable is classified as a parameter, input, or output. Parameters are considered to be variables used in the definition of the model, such as the number of regions and length of the forecast horizon. The listing for input variables contains the source, which includes exogenous reports and organizations, other modules of the NEMS, and other submodules of the EMM. Each variable type is accompanied by a definition and the appropriate units. This inventory also notes if data are aggregated or an alternate naming convention (alias) is used in the mathematical specification of the model equations (Section 4.3) and the derivation of the coefficients (Appendix B). Finally, a listing of ECP subroutines containing each variable is provided.

PARAMETERS

ECP Variable: ECP\$CAP
Definition: Total number of plant types represented in the ECP (dispatchable (17) + intermittent (2) + renewable (5))
Units: Scalar (24)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD

- 1 = Existing Unscrubbed Coal with SO₂ standard ≤ 1.20 lbs / MMbtu
- 2 = Existing Unscrubbed Coal with SO₂ standard ≤ 2.50 lbs / MMbtu
- 3 = Existing Unscrubbed Coal with SO₂ standard ≤ 3.34 lbs / MMbtu
- 4 = Existing Unscrubbed Coal with SO₂ standard > 3.34 lbs / MMbtu
- 5 = Existing Scrubbed Coal with SO₂ standard ≤ 1.20 lbs / MMbtu
- 6 = Existing Scrubbed Coal with SO₂ standard ≤ 2.50 lbs / MMbtu
- 7 = Existing Scrubbed Coal with SO₂ standard ≤ 3.34 lbs / MMbtu
- 8 = Existing Scrubbed Coal with SO₂ standard > 3.34 lbs / MMbtu
- 9 = New Pulverized Coal with Scrubber
- 10 = Advanced Clean Coal Technology
- 11 = Gas/Oil Steam (New or existing)
- 12 = Conventional Gas/Oil Combined Cycle (New or existing)
- 13 = Advanced Gas/Oil Combined Cycle
- 14 = Conventional Combustion Turbine (New or existing)
- 15 = Advanced Combustion Turbine
- 16 = Conventional Nuclear (New or existing)
- 17 = Advanced Nuclear
- 18 = Solar
- 19 = Wind
- 20 = Conventional Hydro
- 21 = Pump Storage Hydro
- 22 = Geothermal
- 23 = Wood
- 24 = Municipal Solid Waste

ECP Variable: ECP\$CIS
Definition: Number of steps for Canadian import supply curve
Units: Scalar (2 steps)
Alias: LP Dimension: $s = 1, \text{ECP\$CIS}$
Level of Aggregation: None
Subroutines: EP\$ETT, EPO\$ETT

- 1 = Low Cost Supply Step
- 2 = High Cost Supply Step

ECP Variable: ECP\$DBNM
Definition: Name assigned to LP model for use by OML
Units: Character ('ACTEMMI')
Alias: None
Level of Aggregation: None
Subroutines: ECPOML

ECP Variable: ECP\$DSM
Definition: Number of DSM program types
Units: Scalar (12)
Alias: LP Dimension: $d = 1, \text{ECP\$DSM}$
Level of Aggregation: None
Subroutines: EP\$DSM

ECP Variable: ECP\$DSP
Definition: Number of dispatchable capacity types
Units: Scalar (17)
Alias: LP Dimension: $c = 1, \text{ECP\$DSP}$
Level of Aggregation: None
Subroutines: EP\$BLD, EP\$RETRO, EP\$BDSP, EP\$ODSP, EP\$INT, EP\$BRNW,

- 1 = Existing Unscrubbed Coal with SO_2 standard ≤ 1.20 lbs / MMbtu
- 2 = Existing Unscrubbed Coal with SO_2 standard ≤ 2.50 lbs / MMbtu
- 3 = Existing Unscrubbed Coal with SO_2 standard ≤ 3.34 lbs / MMbtu
- 4 = Existing Unscrubbed Coal with SO_2 standard > 3.34 lbs / MMbtu
- 5 = Existing Scrubbed Coal with SO_2 standard ≤ 1.20 lbs / MMbtu
- 6 = Existing Scrubbed Coal with SO_2 standard ≤ 2.50 lbs / MMbtu
- 7 = Existing Scrubbed Coal with SO_2 standard ≤ 3.34 lbs / MMbtu
- 8 = Existing Scrubbed Coal with SO_2 standard > 3.34 lbs / MMbtu
- 9 = New Pulverized Coal with Scrubber
- 10 = Advanced Clean Coal Technology
- 11 = Gas/Oil Steam (New or existing)
- 12 = Conventional Gas/Oil Combined Cycle (New or existing)
- 13 = Advanced Gas/Oil Combined Cycle
- 14 = Conventional Combustion Turbine (New or existing)
- 15 = Advanced Combustion Turbine
- 16 = Conventional Nuclear (New or existing)
- 17 = Advanced Nuclear

ECP Variable: ECP\$FILEB
Definition: Name of LP basis file used by OML
Units: Character ('ECP\$DECK')
Alias: None
Level of Aggregation: None
Subroutines: ECPOML

ECP Variable: ECP\$FPH
Definition: Length of full planning horizon (i.e., number of years for life-cycle cost calculations)
Units: Years (30)
Alias: LP Dimension: $z = 1, \text{ECP\$FPH}$
Level of Aggregation: None
Subroutines: ECPOML, EP\$ETT, EP\$RETRO, EP\$BDSP, EPFLPRC, EP\$INT, EP\$BRNW, EPO\$BILD

ECP Variable: ECP\$FPP
Definition: Number of fuel types used by a plant type
Units: Scalar (Maximum=4)
Alias: LP Dimension: $f = 1, \text{ECP\$FPP}$
Level of Aggregation: None
Subroutines: EP\$ODSP

- 1 = Primary Fuel
- 2 = First Alternate Fuel
- 3 = Second Alternate Fuel
- 4 = Third Alternate Choice

ECP Variable: ECP\$INT
Definition: Number of intermittent capacity types
Units: Scalar (2)
Alias: LP Dimension: $i = 1, \text{ECP\$INT}$
Level of Aggregation: None
Subroutines: EP\$BLD, EP\$INT, EP\$BRNW, EPO\$BILD

- 1 = Solar
- 2 = Wind

ECP Variable: ECP\$LCP
Definition: Longest construction lead time
Units: Scalar (4)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD

ECP Variable: ECP\$MSP
Definition: Number of seasonal periods
Units: Scalar (3)
Alias: None
Level of Aggregation: None
Subroutines: EP\$ODSP, EPDRATE

- 1 = Summer
- 2 = Winter
- 3 = Offpeak (Spring,Fall)

ECP Variable: ECP\$NFL
Definition: Number of fuel types used by all capacity types
Units: Scalar (20)
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EP\$ODSP

- 1 = Low-Sulfur Coal ($\text{SO}_2 \leq 1.2$ lb/mmbtu)
- 2 = Medium Sulfur ($1.2 < \text{SO}_2 \leq 2.5$)
- 3 = High Sulfur ($2.5 < \text{SO}_2 \leq 3.34$)
- 4 = Very High Sulfur ($\text{SO}_2 > 3.34$)
- 5 = Distillate Fuel Oil
- 6 = Low-Sulfur Residual Fuel Oil ($\leq 1\%$ sulfur)
- 7 = High-Sulfur Residual Fuel Oil ($> 1\%$ sulfur)
- 8 = Natural Gas--Firm (combined cycle, single-fired steam)
- 9 = Natural Gas--Interruptible (combustion turbines)
- 10 = Natural Gas--Competitive (dual-fired steam)
- 11 = Uranium
- 12 = Water
- 13 = Geothermal Steam
- 14 = Refuse
- 15 = Wood
- 16 = Wind
- 17 = Sun
- 18 = Maximum Natural Gas/Maximum High-Sulfur Residual Fuel Oil/
Minimum Low-Sulfur Residual Fuel Oil
- 19 = Maximum Natural Gas/Maximum Low-Sulfur Residual Fuel Oil/
Minimum High-Sulfur Residual Fuel Oil
- 20 = Maximum Natural Gas/Minimum Distillate Fuel Oil

Note: Each electricity supply region is characterized by a limit on electricity generation from natural gas and high-sulfur residual fuel oil due to fuel availability and environmental regulations. Fuel types 18 through 20 represent combinations of shares for gas and oil consumption in dual-fired units.

ECP Variable: ECP\$OWN
Definition: Ownership types
Units: Scalar (2)
Alias: LP Dimension: o = 1,ECP\$OWN
Level of Aggregation: None
Subroutines: EP\$INT, EP\$BRNW, EPO\$BILD

- 1 = Utility
- 2 = Nonutility

ECP Variable: ECP\$PROB
Definition: Problem name for lp model
Units: Character ('ACTPROB')
Alias: None
Level of Aggregation: None
Subroutines: ECPOML

ECP Variable: ECP\$RNW
Definition: Number of non-intermittent renewable capacity types
Units: Scalar (5)
Alias: LP Dimension: n = 1,ECP\$RNW
Level of Aggregation: None
Subroutines: EP\$BLD, EP\$BRNW, EP\$ORNW

- 1 = Conventional Hydro
- 2 = Pump Storage Hydro
- 3 = Geothermal
- 4 = Wood
- 5 = Municipal Solid Waste

ECP Variable: ECP\$SCR
Definition: Number of clusters of candidates for scrubber retrofits
Units: Scalar (1)
Alias: LP Dimension: u = 1,ECP\$SCR
Level of Aggregation: None
Subroutines: EP\$RETRO, EPO\$RETRO

ECP Variable: ECP\$VLS
Definition: Number of vertical load slices
Units: Scalar (22)
Alias: LP Dimension: 1 = 1,ECP\$VLS
Level of Aggregation: None
Subroutines: EP\$ETT, EP\$ODSP, EPDRATE, EP\$INT, EP\$ORNW, EPO\$AVOID

There are 9 seasonal/time-of-day load groups, as defined below.

<u>Load Group</u>	<u>Months</u>	<u>Hours</u>
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 demands for Summer Daytime, Summer Evening, Winter Daytime, and Winter Evening load groups are approximated using three vertical slices (rectangles): Peak(highest 2% of load), Near Peak(next 49% of load) and OffPeak (lowest 49% of load). The remaining load groups contain two segments, Near Peak (highest 50% of load) and OffPeak (lowest 50% of load) for a total of 22 load segments. The twenty-two load segments are assigned rankings from lowest (1=baseload) to highest (22=peak) and the order varies from region to region. The maximum hourly demand is used as the height of the Peak segment in order to accurately capture the total need for capacity. The average demand is used for the Near Peak and Offpeak segments to accurately capture the need for electricity generation.

ECP Variable: ECP\$XPH
Definition: Length of explicit planning horizon
Units: Years (6)
Alias: LP Dimension: $y = 1, ECP\$XPH$
Level of Aggregation: None
Subroutines: ELECP, ECPOML, EP\$ALLOW, EP\$ETT, EP\$BLD, EP\$PCL, EP\$RETRO, EP\$BDSP, EPFLPRC, EP\$INT, EP\$BRNW, EP\$DSM, EPO\$BILD, EPO\$AVOID, EPO\$BANK

- 1 = First Year of Planning Horizon
- 2 = Second Year of Planning Horizon
- 3 = Third Year of Planning Horizon
- 4 = Fourth Year of Planning Horizon
- 5 = Fifth Year of Planning Horizon
- 6 = Last Year of Planning Horizon

ECP Variable: ECPACT
Definition: Year to write out ACTFILE (e.g. 1995)
Units: Scalar (Default = First Year of Electricity Capacity Planning Submodule Execution.)
Alias: None
Level of Aggregation: None
Source: Run Time Option: User Specified
Subroutines: ECPOML

ECP Variable: ECPBASIS
Definition: Switch to control starting basis
Units: Scalar (Default = 0)
Alias: None
Level of Aggregation: None
Source: Run Time Option: User Specified
Subroutines: ECPOML

- 0 Use starting basis from previous year's solution
- 1 Use starting basis provided as input file

ECP Variable: EFD\$CAP
Definition: Number of dispatchable and renewable capacity types in Electricity Fuel Dispatching Submodule
Units: Scalar (EFD\$DSP(16) + EFD\$RNW(8) = 24)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD

- 1 = Bituminous
- 2 = Bituminous/Subbituminous
- 3 = Subbituminous
- 4 = Subbituminous/Lignite
- 5 = Lignite
- 6 = Oil Steam
- 7 = Oil/Gas Steam
- 8 = Gas Steam
- 9 = Oil Turbine
- 10 = Oil/Gas Turbine
- 11 = Gas Turbines
- 12 = Oil Combined Cycle
- 13 = Oil/Gas Combined Cycle
- 14 = Gas Combined Cycle
- 15 = Nuclear Boiling Water Reactor
- 16 = Nuclear Pressure Water Reactor
- 17 = Conventional Hydroelectric
- 18 = Hydro Pipeline
- 19 = Hydro Reversible
- 20 = Geothermal
- 21 = Municipal Solid Waste
- 22 = Wood/Biomass
- 23 = Solar
- 24 = Wind

ECP Variable: EFD\$DSP
Definition: Number of dispatchable capacity types in Electricity Fuel Dispatching Submodule
Units: Scalar (16)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD

- 1 Bituminous
- 2 Bituminous/Subbituminous
- 3 Subbituminous
- 4 Subbituminous/Lignite
- 5 Lignite
- 6 Oil Steam
- 7 Oil/Gas Steam
- 8 Gas Steam
- 9 Oil Turbine
- 10 Oil/Gas Turbine
- 11 Gas Turbines
- 12 Oil Combined Cycle
- 13 Oil/Gas Combined Cycle
- 14 Gas Combined Cycle
- 15 Nuclear Boiling Water Reactor
- 16 Nuclear Pressure Water Reactor

ECP Variable: EFD\$FPP
Definition: Number of fuel types used by a plant type in Electricity Fuel Dispatching
Units: Scalar (4 -- 1 primary and 3 alternate fuels)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$RETRO

- 1 Primary Fuel
- 2 Secondary Fuel
- 3 Third Choice Fuel
- 4 Fourth Choice

ECP Variable: EFD\$MFRG
Definition: Maximum number of fuel supply regions (including U.S. total) by fuel type in Electricity Fuel Dispatching
Units: Scalar (24 -- 11 Oil Regions (Census Divisions), 22 Gas Regions, 24 Coal Regions)
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC

ECP Variable: EFD\$MSP
Definition: Number of seasonal periods in Electricity Fuel Dispatching
Units: Scalar (6 2-month periods)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$ETT

- 1 = January and February
- 2 = December and March
- 3 = May and April
- 4 = June and September
- 5 = July and August
- 6 = November and October

ECP Variable: EFD\$NFL
Definition: Number of input fuel types (including total) in Electricity Fuel Dispatching
Units: Scalar (20)
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EP\$ODSP

- 1 UILL Low Sulfur Lignite Coal
- 2 UILM Medium Sulfur Lignite Coal
- 3 UILH High Sulfur Lignite Coal
- 4 UILV Very High Sulfur Coal
- 5 UISL Low Sulfur Subbituminous Coal
- 6 UISM Medium Sulfur Subbituminous Coal
- 7 UISH High Sulfur Subbituminous Coal
- 8 UISV Very High Sulfur Subbituminous Coal
- 9 UIBL Low Sulfur Bituminous Coal
- 10 UIBM Medium Sulfur Bituminous Coal
- 11 UIBH High Sulfur Bituminous Coal
- 12 UIBV Very High Sulfur Bituminous Coal
- 13 UIDS Distillate Oil
- 14 UIRL Residual Low Sulfur Oil
- 15 UIRH Residual High Sulfur Oil
- 16 UIGF Natural Gas - Firm
- 17 UIGC Natural Gas - Interruptible
- 18 UIGI Natural Gas - Competitive
- 19 UIUF Nuclear
- 20 UIUR Uranium

ECP Variable: EMMIO
Definition: Memory requirement for LP model in ECP
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: ECPOML

ECP Variable: MNUMCR
Definition: Number of Census Divisions
Units: Scalar (11)
Alias: None
Level of Aggregation: None
Source: Integrating Module
Subroutines: EPFLPRC

- | | |
|----|--------------------|
| 1 | New England |
| 2 | Middle Atlantic |
| 3 | East North Central |
| 4 | West North Central |
| 5 | South Atlantic |
| 6 | East South Central |
| 7 | West South Central |
| 8 | Mountain |
| 9 | Pacific |
| 10 | California |
| 11 | U.S. Total |

ECP Variable: MNUMNR
Definition: Number of Electricity Supply Regions
Units: Scalar (16)
Alias: None
Level of Aggregation: None
Source: Integrating Module
Subroutines: ELECP

- | | | |
|----|-------|-------------------------------------|
| 1 | ECAR | East Central |
| 2 | ERCOT | Texas |
| 3 | MAAC | Mid-Atlantic |
| 4 | MAIN | Mid-American |
| 5 | MAPP | Mid-Continent |
| 6 | NY | New York |
| 7 | NE | New England |
| 8 | FL | Florida |
| 9 | STV | Southern & Tennessee Valley |
| 10 | SPP | Southwest Power Pool |
| 11 | NWP | Northwest Power Pool |
| 12 | RA | Rocky Mountain, Arizona, New Mexico |
| 13 | CNV | California, Southern Nevada |
| 14 | ASCC | Alaska |
| 15 | | Hawaii |
| 16 | | National Total |

ECP Variable: MNUMYR
Definition: Number of NEMS Forecast Years
Units: Scalar (29)
Alias: None
Level of Aggregation: None
Source: Integrating Module
Subroutines: ELECP, ECPOML, EP\$RETRO, EP\$BDSP, EP\$INT, EP\$BRNW, EPO\$BILD

1990-2015, 2020, 2025, 2030

ECP Variable: UIBL
Definition: Index for low-sulfur bituminous coal
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UIBM
Definition: Index for medium-sulfur bituminous coal
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UIBH
Definition: Index for high-sulfur bituminous coal
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UIBV
Definition: Index for very high-sulfur bituminous coal
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UISL
Definition: Index for low-sulfur subbituminous coal
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UISM
Definition: Index for medium-sulfur subbituminous coal
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UISH
Definition: Index for high-sulfur subbituminous coal
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UISV
Definition: Index for very high-sulfur subbituminous coal
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UILL
Definition: Index for low-sulfur lignite
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UILM
Definition: Index for medium-sulfur lignite
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UILH
Definition: Index for high-sulfur lignite
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UISV
Definition: Index for very high-sulfur lignite
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC, EPO\$BILD

ECP Variable: UNFUELS
Definition: Number of input fuels for dispatching
Units: Scalar (19)
Alias: None
Level of Aggregation: None
Subroutines: EPFLPRC

- 1 UILL Low Sulfur Lignite Coal
- 2 UILM Medium Sulfur Lignite Coal
- 3 UILH High Sulfur Lignite Coal
- 4 UILV Very High Sulfur Coal
- 5 UISL Low Sulfur Subbituminous Coal
- 6 UISM Medium Sulfur Subbituminous Coal
- 7 UISH High Sulfur Subbituminous Coal
- 8 UISV Very High Sulfur Subbituminous Coal
- 9 UIBL Low Sulfur Bituminous Coal
- 10 UIBM Medium Sulfur Bituminous Coal
- 11 UIBH High Sulfur Bituminous Coal
- 12 UIBV Very High Sulfur Bituminous Coal
- 13 UIDS Distillite Oil
- 14 UIRL Residual Low Sulfur Oil
- 15 UIRH Residual High Sulfur Oil
- 16 UIGF Natural Gas - Firm
- 17 UIGC Natural Gas - Interruptible
- 18 UIGI Natural Gas - Competitive
- 19 UIUF Nuclear

ECP Variable: UNRGNS
Definition: Number of Electricity Supply Regions
Units: Scalar (13--excludes Alaska and Hawaii)
Allas: LP Dimension: r = 1,UNRGNS
Level of Aggregation: None
Subroutines: ECPOML, EP\$ETT, EPO\$ETT

1	ECAR	East Central
2	ERCOT	Texas
3	MAAC	Mid-Atlantic
4	MAIN	Mid-American
5	MAPP	Mid-Continent
6	NY	New York
7	NE	New England
8	FL	Florida
9	STV	Southern & Tennessee Valley
0	SPP	Southwest Power Pool
A	NWP	Northwest Power Pool
B	RA	Rocky Mountain, Arizona, New Mexico
C	CNV	California, Southern Nevada

ECP Variable: UPBND
Definition: Name of bound row for LP model
Units: Character ('BND1')
Allas: None
Level of Aggregation: None
Subroutines: ECPOML, EP\$ALLOW, EP\$ETT, EP\$MRM, EP\$BLD, EP\$BDSP, EP\$INT, EP\$BRNW, EP\$ORNW

ECP Variable: UPDETT
Definition: Switch to allow/disallow interregional build decisions for dispatchable technologies
Units: Scalar
Allas: None
Level of Aggregation: Dispatchable capacity types
Subroutines: EP\$BLD, EP\$BDSP, EPO\$BILD

0	Disallow
1	Allow

ECP Variable: UPDMCD
Definition: Code for DSM program groups
Units: Character ('D1' - 'DB')
Alias: None
Level of Aggregation: DSM program groups
Source: Load and Demand-Side Management Submodule (not yet linked)
Subroutines: EP\$DSM

ECP Variable: UPDNUG
Definition: Switch to allow/disallow nonutility build decisions for dispatchable capacity types
Units: Scalar
Alias: None
Level of Aggregation: Dispatchable capacity types
Subroutines: EP\$BLD, EP\$BDSP

0 Disallow
 1 Allow

ECP Variable: UPEFPT
Definition: Asset type for pricing
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

'1' Coal
 '3' Steam
 '5' Combined Cycle
 '9' Combustion Turbine
 '10' Nuclear
 '11' Pumped Storage
 '12' Renewables

ECP Variable: UPFLCD
Definition: Fuels codes for column names in LP model
Units: Character
Alias: None
Level of Aggregation: Sulfur categories for coal
Subroutines: EPO\$DSP

CL Low-Sulfur Coal ($\text{SO}_2 \leq 1.2$ lb/mmbtu)
 CM Medium Sulfur ($1.2 < \text{SO}_2 \leq 2.5$)
 CH High Sulfur ($2.5 < \text{SO}_2 \leq 3.34$)
 CV Very High Sulfur ($\text{SO}_2 > 3.34$)
 DS Distillate Fuel Oil
 RL Low-Sulfur Residual Fuel Oil ($\leq 1\%$ sulfur)
 RH High-Sulfur Residual Fuel Oil ($> 1\%$ sulfur)
 GF Natural Gas--Firm (combined cycle, single-fired steam)
 GI Natural Gas--Interruptible (combustion turbines)
 GC Natural Gas--Competitive (dual-fired steam)

UR	Uranium
WA	Water
GS	Geothermal Steam
RF	Refuse
WO	Wood
WI	Wind
SU	Sun
GH	Max Gas/Max RH/Min RL
GL	Max Gas/Max RL/Min RH
GD	Max Gas/Min DS

ECP Variable: UPIETT
Definition: Switch to allow/disallow interregional build decisions for intermittent technologies
Units: Scalar
Alias: None
Level of Aggregation: Intermittent capacity types
Subroutines: EP\$INT, EPO\$BILD

0	Disallow
1	Allow

ECP Variable: UPINCD
Definition: Intermittent technology codes for row/column names in LP model
Units: Character
Alias: None
Level of Aggregation: None
Subroutines: EP\$INT, EPO\$BILD

SO	Solar
WN	Wind

ECP Variable: UPINUG
Definition: Switch to allow/disallow nonutility build decisions for intermittent technologies
Units: Scalar
Alias: None
Level of Aggregation: Intermittent technologies
Subroutines: EP\$INT, EP\$BDSP

0	Disallow
1	Allow

ECP Variable: UPLDCD
Definition: Load segment codes for row/column names in LP model
Units: Character ('1' - 'L')
Alias: None
Level of Aggregation: None
Subroutines: EP\$ETT, EP\$LOAD, EP\$INT, EP\$ORNW, EPO\$AVOID

The twenty-two load slices are derived from the nine load groups defined below.

		<u>Hours in Load Group</u>	<u>Load Segments</u>
1	Summer Daytime	7:00 a.m. - 6:00 p.m.	Peak, Near Peak, Off Peak
2	Summer Evening	5:00 a.m. - 7:00 a.m. 6:00 p.m. - 12:00 p.m.	Peak, Near Peak, Off Peak
3	Summer Night	12:00 p.m. - 5:00 a.m.	Peak & Off Peak
4	Winter Daytime	7:00 a.m. - 6:00 p.m.	Peak, Near Peak, Off Peak
5	Winter Evening	5:00 a.m. - 7:00 a.m. 6:00 p.m. - 12:00 p.m.	Peak, Near Peak, Off Peak
6	Winter Night	12:00 p.m. - 5:00 a.m.	Peak & Off Peak
7	Fall/Spring Daytime	7:00 a.m. - 6:00 p.m.	Peak & Off Peak
8	Fall/Spring Evening	5:00 a.m. - 7:00 a.m. 6:00 p.m. - 12:00 p.m.	Peak & Off Peak
9	Fall/Spring Night	12:00 p.m. - 5:00 a.m.	Peak & Off Peak

The Summer Daytime, Summer Evening, Winter Daytime and Winter Evening load groups are broken into three segments: Peak(20% of load), Near Peak(49% of Load) and OffPeak(49% of Load). The remaining load groups contain two segments, Peak(50%) and Off Peak(50%) for a total of 22 load segments. The twenty-two load segments are assigned rankings from Base Load (1) to Peak Load (22) based on regional load curves. The one character code used to represent the twenty-two load segments in the ECP are 1 (Base) through L (Peak).

ECP Variable: UPMDCD
Definition: Mode of operation (e.g., base, intermediate, peak) codes for column names in LP model
Units: Character ('1' - 'L')
Alias: None
Level of Aggregation: None
Subroutines: EP\$ODSP

- 1 Operates in Load Segments 1-22 ("Base" Mode-of-Operation)
- 2 Operates in Load Segments 2-22
- 3 Operates in Load Segments 3-22
- 4 Operates in Load Segments 4-22
- 5 Operates in Load Segments 5-22
- 6 Operates in Load Segments 6-22
- 7 Operates in Load Segments 7-22
- 8 Operates in Load Segments 8-22
- 9 Operates in Load Segments 9-22
- 0 Operates in Load Segments 10-22

A	Operates in Load Segments 11-22
B	Operates in Load Segments 12-22
C	Operates in Load Segments 13-22
D	Operates in Load Segments 14-22
E	Operates in Load Segments 15-22
F	Operates in Load Segments 16-22
G	Operates in Load Segments 17-22
H	Operates in Load Segments 18-22
I	Operates in Load Segments 19-22
J	Operates in Load Segments 20-22
K	Operates in Load Segments 21-22
L	Operates in Load Segment 22 ("Peak" Mode-of-Operation)

ECP Variable: UPOBJ
Definition: Name of objective function in LP model
Units: Character ('ECPCOSTS')
Alias: None
Level of Aggregation: None
Subroutines: ECPOML, EP\$ETT, EP\$MRM, EP\$BLD, EP\$RETRO, EP\$BDSP, EP\$ODSP, EP\$INT, EP\$BRNW, EP\$ORNW, EP\$DSM

ECP Variable: UPOWNCD
Definition: Type of ownership for row/column names in LP model
Units: Character
Alias: None
Level of Aggregation: None
Subroutines: EP\$BLD, EP\$BDSP, EP\$INT, EP\$BRNW, EP\$OBILD

U Utility
N Nonutility

ECP Variable: UPPLCD
Definition: Dispatchable capacity type codes for row/column names in LP model
Units: Character
Alias: None
Level of Aggregation: None
Subroutines: EP\$BLD, EP\$RETRO, EP\$BDSP, EP\$ODSP, EPO\$BILD

XL	Existing Unscrubbed Coal with SO2 standard \leq 1.20 lbs / MMbtu
XM	Existing Unscrubbed Coal with SO2 standard \leq 2.50 lbs / MMbtu
XH	Existing Unscrubbed Coal with SO2 standard \leq 3.34 lbs / MMbtu
XV	Existing Unscrubbed Coal with SO2 standard $>$ 3.34 lbs / MMbtu
SL	Existing Scrubbed Coal with SO2 standard \leq 1.20 lbs / MMbtu
SM	Existing Scrubbed Coal with SO2 standard \leq 2.50 lbs / MMbtu
SH	Existing Scrubbed Coal with SO2 standard \leq 3.34 lbs / MMbtu
SV	Existing Scrubbed Coal with SO2 standard $>$ 3.34 lbs / MMbtu
PC	New Pulverized Coal with Scrubber
IG	Advanced Clean Coal Technology
ST	Gas/Oil Steam (New or existing)
CC	Conventional Gas/Oil Combined Cycle (New or existing)
AC	Advanced Gas/Oil Combined Cycle
CT	Conventional Combustion Turbine (New or existing)

AT	Advanced Combustion Turbine
CN	Conventional Nuclear (New or existing)
AN	Advanced Nuclear

ECP Variable: UPRETT
Definition: Switch to allow/disallow interregional build decisions for renewable (excluding intermittent) technologies
Units: Scalar
Alias: None
Level of Aggregation: Renewable capacity types
Subroutines: EP\$BLD, EP\$BRNW, EPO\$BILD

0	Disallow
1	Allow

ECP Variable: UPRGCD
Definition: Electricity Supply Region codes for row/column names in LP model
Units: Character ('1' - 'U')
Alias: None
Level of Aggregation: None
Subroutines: EP\$ETT, EP\$MRM, EP\$BLD, EP\$PCL, EP\$LOAD, EP\$RETRO, EP\$BDSP, EP\$ODSP, EP\$INT, EP\$BRNW, EP\$ORNW, EP\$DSM, EPO\$BILD, EPO\$RETRO, EPO\$AVOID, EPO\$ETT

1	ECAR	East Central
2	ERCOT	Texas
3	MAAC	Mid-Atlantic
4	MAIN	Mid-American
5	MAPP	Mid-Continent
6	NY	New York
7	NE	New England
8	FL	Florida
9	STV	Southern & Tennessee Valley
0	SPP	Southwest Power Pool
A	NWP	Northwest Power Pool
B	RA	Rocky Mountain, Arizona, New Mexico
C	CNV	California, Southern Nevada
U		Total United States

ECP Variable: UPRHS
Definition: Name of right-hand side vector in LP model
Units: Character ('RHSECP')
Alias: None
Level of Aggregation: None
Subroutines: ECPOML, EP\$ALLOW, EP\$ETT, EP\$MRM, EP\$BLD, EP\$PCL, EP\$LOAD, EP\$RETRO, EP\$INT, EP\$BRNW

ECP Variable: UPRNCD
Definition: Renewable (excluding intermittent) technology codes for row/column names in LP model
Units: Character
Alias: None
Level of Aggregation: None
Subroutines: EP\$BLD, EP\$BRNW, EP\$ORNW, EPO\$BILD

HY Conventional Hydro
 PS Pump Storage Hydro
 GT Geothermal
 WD Wood
 MS Municipal Solid Waste

ECP Variable: UPRNUG
Definition: Switch to allow/disallow nonutility build decisions for renewable (excluding intermittent) technologies
Units: Scalar
Alias: None
Level of Aggregation: Renewable capacity types
Subroutines: EP\$INT, EP\$BDSP

0 Disallow
 1 Allow

ECP Variable: UPSSCD
Definition: Retrofit cluster code column names in LP model
Units: Character ('1')
Alias: None
Level of Aggregation: None
Subroutines: EP\$RETRO, EPO\$RETRO

ECP Variable: UPVTYP
Definition: Vintage type
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EP\$BLD, EP\$BDSP, EP\$INT, EP\$BRNW, EPO\$BILD

0 Existing
 1 New

ECP Variable: UPYRCD
Definition: Year code for row/column names in LP model
Units: Character ('1' - '6')
Alias: None
Level of Aggregation: None
Subroutines: EP\$ALLOW, EP\$ETT, EP\$MRM, EP\$BLD, EP\$PCL, EP\$LOAD, EP\$RETRO, EP\$BDSP, EP\$ODSP, EP\$INT, EP\$BRNW, EP\$ORNW, EP\$DSM, EPO\$BILD, EPO\$RETRO, EPO\$AVOID, EPO\$BANK, EPO\$ETT

1 First Year of Planning Horizon
 2 Second Year of Planning Horizon
 3 Third Year of Planning Horizon
 4 Fourth Year of Planning Horizon
 5 Fifth Year of Planning Horizon
 6 Last Year of Planning Horizon

ECP Variable: USW_ECP
Definition: Switch to allow/disallow execution of Electricity Capacity Planning Submodule (user-option)
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: ELECP

0 Disallow
 1 Allow

ECP Variable: USW_RNW
Definition: Switch to allow/disallow penetration of renewable technologies (user-option)
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EP\$INT, EP\$BRNW

0 Disallow
 1 Allow

ECP Variable: USYEAR
Definition: Actual year corresponding to the forecast year
Units: Scalar (e.g., 1=1990)
Alias: None
Level of Aggregation: None
Subroutines: ELECP, ECPOML, EP\$BLD, EPO\$BILD, EPO\$RETRO

INPUT VARIABLES

ECP Variable: BIOUP
Definition: Upper bound for biomass capacity additions
Units: Megawatts
Alias: RNWL_r
Level of Aggregation: Electricity Supply Region
Source: Renewable Fuels Module
Subroutines: EP\$BRNW

ECP Variable: CURITR
Definition: Current NEMS Iteration
Units: Scalar
Alias: None
Level of Aggregation: None
Source: Integrating Module
Subroutines: ECPOML

ECP Variable: CURIYR
Definition: Current NEMS Forecast Year (1 = 1990)
Units: Scalar
Alias: None
Level of Aggregation: None
Source: Integrating Module
Subroutines: ELECP, ECPOML, EP\$ALLOW, EP\$ETT, EP\$BLD, EP\$RETRO, EP\$BDSP, EPFLPRC, EP\$ODSP, EP\$INT, EP\$BRNW, EP\$ORNW, EPO\$BILD, EPO\$RETRO, EPO\$BANK, EPO\$ETT

ECP Variable: EPALSO2
Definition: Sulfur dioxide emissions allowances
Units: Thousand tons
Alias: ALW_y
Level of Aggregation: National
Source: Environmental Protection Agency, "National Allowance Data Base - Version 2.11"
Subroutines: EP\$ALLOW

ECP Variable: EPCCRF
Definition: Fixed charge factor for transmission
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region/Capacity Type
Source: Office of Integrated Analysis and Forecasting
Subroutines: EP\$BDSP, EP\$INT, EP\$BRNW

ECP Variable: EPCFOM
Definition: Fixed operations and maintenance cost for transmission
Units: \$ per Kilowatt
Alias: CTRN_{year}
Level of Aggregation: Electricity Supply Region/Capacity Type
Source: OnLocation, Inc.
 "Draft Data Inputs for Implementation of ETT"
 Deliverable 6, Task 92086, Contract DE-AC01-88EI21033
 March 1993
Subroutines: EP\$BDSP, EP\$INT, EP\$BRNW

ECP Variable: EPCLRG
Definition: Coal Distribution Supply (CDS) Region for siting new coal-fired units
Units: None
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Office of Integrated Analysis and Forecasting
Subroutines: EPO\$BILD

ECP Variable: EPCOVR
Definition: Overnight capital cost for transmission
Units: \$ per Kilowatt
Alias: None
Level of Aggregation: Electricity Supply Region
Source: OnLocation, Inc.
 "Draft Data Inputs for Implementation of ETT"
 Deliverable 6, Task 92086, Contract DE-AC01-88EI21033
 March 1993
Subroutines: EP\$BDSP, EP\$INT, EP\$BRNW, EPO\$BILD

ECP Variable: EPCRMP
Definition: Electricity Supply Region to Census Division Mapping
Units: Million Btu
Alias: None
Level of Aggregation: Electricity Supply Regions/Census Divisions
Source: Electricity Fuel Dispatch (EFD) Submodule
Subroutines: EPFLPRC

ECP Variable: EPDCCR
Definition: Contribution to reserve margin made by Demand-Side Management Technologies
Units: Fraction
Alias: RMD_{yrzd}
Level of Aggregation: Electricity Supply Region
Source: Load and Demand-Side Management (LDSM) Submodule
Subroutines: EP\$DSM

ECP Variable: EPDINV
Definition: Cumulative net present value of DSM investments
Units: \$ per Kilowatt (nominal)
Alias: CDSM_{yr}
Level of Aggregation: Electricity Supply Region
Source: Load and Demand-Side Management (LDSM) Submodule
Subroutines: EP\$DSM

ECP Variable: EPDLSI
Definition: Amount of capacity requirement eliminated or created in vertical load slices by Demand-Side Management Technologies.
Units: Fraction
Alias: ELD_{yrzdl}
Level of Aggregation: Electricity Supply Region
Source: Load and Demand-Side Management (LDSM) Submodule
Subroutines: EP\$DSM

ECP Variable: EPDSCRT
Definition: Utility discount rate (nominal, tax-adjusted rate of return)
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Electricity Finance and Pricing (EFP) Submodule
Subroutines: EP\$ETT, EP\$RETRO, EP\$BDSP, EP\$FLPRC, EP\$ODSP, EP\$INT, EP\$BRNW, EP\$ORNW

ECP Variable: EPFLRG
Definition: Electricity Supply Region to Fuel Supply Region Mapping
Units: Million Btu
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Electricity Fuel Dispatch (EFD) Submodule
Subroutines: EP\$FLPRC

ECP Variable: EPFLTP
Definition: Input fuels used in dispatchable capacity types
Units: None
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting
Subroutines: EP\$ODSP

ECP Variable:	EPFMAP
Definition:	Mapping between EFD and ECP fuel types
Units:	Million Btu
Alias:	None
Level of Aggregation:	None
Source:	Electricity Fuel Dispatch (EFD) Submodule
Subroutines:	EPFLPRC, EP\$ODSP

ECP Variable:	EPFSOX
Definition:	Sulfur dioxide emission rate by fuel type
Units:	Pounds per million BTU
Alias:	None
Level of Aggregation:	Electricity Supply Region
Source:	Fuel Supply Modules
Subroutines:	EP\$ODSP

ECP Variable:	EPHGHT
Definition:	Height of vertical load slices
Units:	Gigawatts
Alias:	ELC _{yr}
Level of Aggregation:	Electricity Supply Region
Source:	Load and Demand Side Management (LDSM) Submodule
Subroutines:	EP\$ODSP, EP\$LOAD

ECP Variable:	EPIACF
Definition:	Average capacity factor for intermittent renewable capacity types
Units:	Fraction
Alias:	None
Level of Aggregation:	Electricity Supply Region
Source:	Renewable Fuels Module
Subroutines:	EP\$INT, EP\$BILD

ECP Variable:	EPIAVL
Definition:	Commercial operation date for intermittent renewable capacity types
Units:	Year
Alias:	None
Level of Aggregation:	None
Source:	Renewable Fuels Module
Subroutines:	EP\$INT

ECP Variable: EPICAP
Definition: Existing capacity for intermittent renewable capacity types
Units: Megawatts
Alias: EXI_{yri}
Level of Aggregation: Electricity Supply Region
Source: EIA Form-860, EIA Form-867: Existing & Planned Capacity
 Previous years ECP model output: Unplanned Capacity
Subroutines: EP\$INT

ECP Variable: EPICCR
Definition: Capacity credit for intermittent renewable capacity types
Units: Fraction
Alias: RMI_{yri}
Level of Aggregation: Electricity Supply Region
Source: Renewable Fuels Module
Subroutines: EP\$INT

ECP Variable: EPICFC
Definition: Capacity factor by load segment for intermittent renewable capacity types
Units: Fraction
Alias: ELI_{yri}
Level of Aggregation: Electricity Supply Region and Seasonal/Time-of-Day Period
Source: Renewable Fuels Module
Subroutines: EP\$INT

ECP Variable: EPICLT
Definition: Construction lead time for intermittent renewable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EP\$INT, EPO\$BILD

ECP Variable: EPICPR
Definition: Construction profile for intermittent renewable capacity types
Units: Fraction
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EP\$INT, EPO\$BILD

ECP Variable: EPIELF
Definition: Economic life for intermittent renewable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EP\$INT, EPO\$BILD

ECP Variable: EPIEXT
Definition: Externality costs for intermittent renewable capacity types
Units: \$ per Thousand Kilowatthours
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Putnam, Hayes & Bartlett, Inc.
 "Impact of Externality Regulations on Coal-Based Technologies for Electricity Generation"
 April 1993
Subroutines: EP\$INT

ECP Variable: EPIFOM
Definition: Fixed operations and maintenance cost for intermittent renewable capacity types
Units: \$ per Kilowatt
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EP\$INT, EPO\$BILD

ECP Variable: EPIHRT
Definition: Heat rate for intermittent renewable capacity types
Units: Btu per Kilowatthour
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EP\$INT, EPO\$BILD

ECP Variable: EPINCLF
Definition: Contract life for nonutility intermittent renewable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: OnLocation, Inc.
 "NUGS Model Revisions"
 Deliverable 9, Task 92080, Contract DE-AC01-88EI21033
 January 1993
Subroutines: EP\$INT, EPO\$BILD

ECP Variable: EPINLLF
Definition: Loan life for nonutility intermittent renewable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: OnLocation, Inc.
 "NUGS Model Revisions"
 Deliverable 9, Task 92080, Contract DE-AC01-88EI21033
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Subroutines: EP\$INT, EPO\$BILD

ECP Variable: EPIOVR
Definition: Overnight capital cost for intermittent renewable capacity types
Units: \$ per Kilowatt
Alias: CINT_{yr}
Level of Aggregation: Electricity Supply Region
Source: Renewable Fuels Module
Subroutines: EP\$INT, EPO\$BILD

ECP Variable: EPITLF
Definition: Tax life for intermittent renewable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Tax Reform Act of 1986
Subroutines: EP\$INT, EPO\$BILD

ECP Variable: EPIUCLF
Definition: Contract life for utility intermittent renewable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting
Subroutines: EP\$INT

ECP Variable: EPIVOM
Definition: Variable operations and maintenance cost for intermittent renewable capacity types
Units: \$ per Thousand Kilowatthours
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Renewable Fuels Module
Subroutines: EP\$INT

ECP Variable: EPLDGR
Definition: Load group category
Units: None
Alias: None
Level of Aggregation: Season/Time-of-Day Period
Source: Load and Demand-Side Management (LDSM) Submodule
Subroutines: EP\$MRM, EP\$BLD, EP\$LOAD, EP\$ODSP, EP\$BRNW

ECP Variable: EPMRM
Definition: Minimum reserve margin
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: North American Electric Reliability Council
 "Coordinated Bulk Power Supply Report"
Subroutines: EP\$MRM, EP\$BLD, EP\$BRNW

ECP Variable: EPNFDT
Definition: Nonutility debt fraction
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: OnLocation, Inc.
 "NUGS Model Revisions"
 Deliverable 9, Task 92080, Contract DE-AC01-88EI21033
 January 1993
Subroutines: EP\$BDSP, EP\$INT, EP\$BRNW, EPO\$BILD

ECP Variable: EPNIPRM
Definition: Nonutility interest premium
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: OnLocation, Inc.
 "NUGS Model Revisions"
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Subroutines: EP\$BDSP, EP\$INT, EP\$BRNW, EPO\$BILD

ECP Variable: EPNRPRM
Definition: Nonutility return-on-equity premium
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: OnLocation, Inc.
 "NUGS Model Revisions"
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Subroutines: EP\$BDSP, EP\$INT, EP\$BRNW, EPO\$BILD

ECP Variable: EPNSCR
Definition: Number of plants in a retrofit group (cluster)
Units: None
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Electricity Fuel Dispatch (EFD) Submodule
Subroutines: EPO\$RETRO

ECP Variable: EPNSTP
Definition: Number of vertical segments in load duration curve
Units: None
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting
Subroutines: EP\$LOAD, EP\$ODSP

ECP Variable: EPPAVL
Definition: Commercial operation date for dispatchable capacity types
Units: Year
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$BDSP, EP\$ODSP

ECP Variable: EPPCAP
Definition: Existing capacity for dispatchable capacity types
Units: Megawatts
Alias: EXC_{yr}
Level of Aggregation: Electricity Supply Region
Source: EIA Form-860, EIA Form-867: Existing & Planned Capacity
 Previous years ECP model output: Unplanned Capacity
Subroutines: EP\$BLD, EP\$BDSP, EP\$BRNW

ECP Variable: EPPCFB
Definition: Capacity factor bounds for dispatchable capacity types
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$ODSP, EP\$BRNW

ECP Variable: EPPCLT
Definition: Construction lead time for dispatchable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$BLD, EP\$BDSP, EP\$BRNW

ECP Variable: EPPCPR
Definition: Construction profile for dispatchable capacity types
Units: Fraction
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: EPPEAK
Definition: Peak Load
Units: Gigawatts
Alias: RMQ_{yr}
Level of Aggregation: None
Source: Load and Demand-Side Management (LDSM) Submodule
Subroutines: EP\$MRM, EP\$BLD, EP\$INT, EP\$BRNW

ECP Variable: EPPELF
Definition: Economic life for dispatchable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: EPPEXT
Definition: Externality costs for dispatchable capacity types
Units: \$ per Thousand Kilowatthours
Alias: None
Level of Aggregation: Electricity Supply Regions
Source: Putnam, Hayes & Bartlett, Inc.
 "Impact of Externality Regulations on Coal-Based Technologies for Electricity
 Generation"
 April 1993
Subroutines: EP\$ODSP

ECP Variable: EPPFL
Definition: Present value of expected fuel prices
Units: \$ per Million Btu (nominal) at start year for current planning cycle
Alias: None
Level of Aggregation: None
Source: Integrating Module: Constant dollar fuel prices
 Macroeconomic Module: Inflation rates
Subroutines: EPFLPRC, EP\$ODSP

ECP Variable: EPPFOM
Definition: Fixed operations and maintenance cost for dispatchable capacity types
Units: \$ per Kilowatt
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: EPPFOR
Definition: Forced outage rate for dispatchable capacity types
Units: Fraction
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$ODSP

ECP Variable: EPPHRT
Definition: Heat rate for dispatchable capacity types
Units: Btu per Kilowatthour
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies": New Technologies
 EIA Form-860, EIA Form-867: Existing Technologies
Subroutines: EP\$ODSP, EPO\$BILD

ECP Variable: EPPMAP
Definition: Mapping from ECP to EFD plant types
Units: None
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting
Subroutines: EPO\$BILD

ECP Variable: EPPMCF
Definition: Maximum capacity factor for dispatchable capacity types
Units: None
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Argonne National Laboratories
"Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$ODSP

ECP Variable: EPPNCLF
Definition: Contract life for nonutility dispatchable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: OnLocation, Inc.
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Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: EPPNLLF
Definition: Loan life for nonutility dispatchable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: OnLocation, Inc.
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Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: EPPOVR
Definition: Overnight capital cost for dispatchable capacity types
Units: \$ per Kilowatt
Alias: CBLD_{yr00}
Level of Aggregation: Electricity Supply Region
Source: Argonne National Laboratories
"Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: EPPPMR
Definition: Planned maintenance rate for dispatchable capacity types
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Argonne National Laboratories
"Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$ODSP

ECP Variable: EPPSEF
Definition: Scrubber efficiency rate
Units: Fraction
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$ODSP

ECP Variable: EPPSRT
Definition: Sulfur dioxide emission rate for scrubbed plants
Units: Pounds per Million Btu
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$ODSP

ECP Variable: EPPTLF
Definition: Tax life for dispatchable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Tax Reform Act of 1986
Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: EPPUCLF
Definition: Contract life for utility dispatchable capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting
Subroutines: EP\$BDSP

ECP Variable: EPPVOM
Definition: Variable operations and maintenance cost for dispatchable capacity types
Units: \$ per Thousand Kilowatthours
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$ODSP

ECP Variable: EPRAVL
Definition: Commercial operation date for renewable (excluding intermittent) capacity types
Units: Year
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EP\$BRNW

ECP Variable: EPRCAP
Definition: Existing capacity for renewable (excluding intermittent) capacity types
Units: Megawatts
Alias: EXR_{ym}
Level of Aggregation: Electricity Supply Region
Source: EIA Form-860, EIA Form-867: Existing & Planned Capacity
 Previous years ECP model output: Unplanned Capacity
Subroutines: EP\$BLD, EP\$BRNW, EP\$ORNW

ECP Variable: EPRCCR
Definition: Capacity credit for renewable (excluding intermittent) capacity types
Units: Fraction
Alias: RMR_{ym}
Level of Aggregation: Electricity Supply Region
Source: Renewable Fuels Module
Subroutines: EP\$BLD, EP\$BRNW

ECP Variable: EPRCFC
Definition: Maximum capacity factor for renewable (excluding intermittent) capacity types
Units: Fraction
Alias: ELR_{ymim}
Level of Aggregation: Electricity Supply Region
Source: Renewable Fuels Module
Subroutines: EP\$ORNW, EPO\$BILD

ECP Variable: EPRCLT
Definition: Construction lead time for renewable (excluding intermittent) capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EP\$BLD, EP\$BRNW, EPO\$BILD

ECP Variable: EPRCPR
Definition: Construction profile for renewable (excluding intermittent) capacity types
Units: Fraction
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EP\$BRNW, EPO\$BILD

ECP Variable: EPRELF
Definition: Economic life for renewable (excluding intermittent) capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EP\$BRNW, EPO\$BILD

ECP Variable: EPREXT
Definition: Externality costs for renewable (excluding intermittent) capacity types
Units: \$ per Thousand Kilowatthours
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Putnam, Hayes & Bartlett, Inc.
 "Impact of Externality Regulations on Coal-Based Technologies for Electricity
 Generation"
 April 1993
Subroutines: EP\$ORNW

ECP Variable: EPRFOM
Definition: Fixed operation and maintenance cost for renewable (excluding intermittent) capacity types
Units: \$ per Kilowatt
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EP\$BRNW

ECP Variable: EPRFOR
Definition: Forced outage rate for renewable (excluding intermittent) capacity types
Units: Fraction
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EP\$ORNW

ECP Variable: EPRHRT
Definition: Heat rate for renewable (excluding intermittent) capacity types
Units: Btu per Kilowatthour
Alias: None
Level of Aggregation: None
Source: Renewable Fuels Module
Subroutines: EPO\$BILD

ECP Variable: EPRNCLF
Definition: Contract life for nonutility renewable (excluding intermittent) capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: OnLocation, Inc.
 "NUGS Model Revisions"
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 January 1993
Subroutines: EP\$BRNW, EPO\$BILD

ECP Variable: EPRNLLF
Definition: Loan life for nonutility renewable (excluding intermittent) capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: OnLocation, Inc.
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Subroutines: EP\$BRNW, EPO\$BILD

ECP Variable: EPROVR
Definition: Overnight capital cost for renewable (excluding intermittent) capacity types
Units: \$ per Kilowatt
Alias: CRNW_{ymo}
Level of Aggregation: Electricity Supply Region
Source: Renewable Fuels Module
Subroutines: EP\$BRNW, EPO\$BILD

ECP Variable: EPRTBS
Definition: Initial utility rate base
Units: Millions of \$ (nominal)
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Electricity Finance & Pricing (EFP) Submodule
Subroutines: EP\$PCL

ECP Variable: EPRTLF
Definition: Tax life for renewable (excluding intermittent) capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Tax Reform Act of 1986
Subroutines: EP\$BRNW, EPO\$BII.D

ECP Variable: EPRUCLF
Definition: Contract life for utility renewable (excluding intermittent) capacity types
Units: Years
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting
Subroutines: EP\$BRNW

ECP Variable: EPRVOM
Definition: Variable operations and maintenance cost for renewable (excluding intermittent) capacity types
Units: \$ per Thousand Kilowatthours
Alias: $COPR_{ym}$
Level of Aggregation: Electricity Supply Region
Source: Renewable Fuels Module
Subroutines: EP\$ORNW

ECP Variable: EPSCAP
Definition: Upper limit on existing capacity that can be retrofitted with scrubbers
Units: Megawatts
Alias: $FGDL_{cru}$
Level of Aggregation: Electricity Supply Region
Source: Environmental Protection Agency
 "Retrofit Costs for SO₂ and NO_x Control Options at 200 Coal-Fired Plants"
 March 1991
Subroutines: EP\$RETRO

ECP Variable: EPSCLT
Definition: Construction leadtime for installing retrofits on existing capacity
Units: Years
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$RETRO, EPO\$RETRO

ECP Variable: EPSCPEN
Definition: Capacity penalty for operating scrubbers
Units: Fraction
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Retrofit Emission Controls"
Subroutines: EP\$RETRO, EPO\$RETRO

ECP Variable: EPSCPR
Definition: Construction profile for installing retrofits on existing capacity.
Units: Fraction
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$RETRO

ECP Variable: EPSCR2
Definition: Capacity type for existing unit retrofitted with scrubbers (i.e., unscrubbed instead of scrubbed)
Units: None
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting
Subroutines: EP\$RETRO, EPO\$RETRO

ECP Variable: EPSELF
Definition: Economic life for scrubber retrofits on existing capacity
Units: Years
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting
Subroutines: EP\$RETRO, EPO\$RETRO

ECP Variable: EPSHPEN
Definition: Heat rate (efficiency) penalty for operating scrubbers
Units: Fraction
Alias: None
Level of Aggregation: None
Source: Argonne National Laboratories
 "Retrofit Emission Controls"
Subroutines: EPO\$RETRO

ECP Variable: EPSOVR
Definition: Overnight capital cost for retrofitting existing capacity with scrubbers
Units: \$ per Kilowatt
Alias: CFGD_{yrcku}
Level of Aggregation: Electricity Supply Region and Retrofit Cluster
Source: Environmental Protection Agency
 "Retrofit Costs for SO₂ and NO_x Control Options at 200 Coal-Fired Plants"
 March 1991: Unit-specific retrofit factors
 Argonne National Laboratories
 "Retrofit Emission Controls": Generic retrofit costs
Subroutines: EP\$RETRO, EPO\$RETRO

ECP Variable: EPSPK
Definition: Peak load
Units: Gigawatts
Alias: None
Level of Aggregation: Electricity Supply Region and Seasonal/Time-of-Day Period
Source: Load and Demand Side Management Submodule
Subroutines: EP\$ODSP

ECP Variable: EPSREC
Definition: Plant database record number for retrofitted capacity Peak load
Units: Gigawatts
Alias: None
Level of Aggregation: Electricity Supply Region and Retrofit Cluster
Source: Electricity Fuel Dispatch (EFD) Submodule
Subroutines: EPO\$RETRO

ECP Variable: EPTCRF
Definition: Transmission annuity factor for interregional capacity additions
Units: Fraction
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting
Subroutines: EP\$BDSP, EP\$INT, EP\$BRNW

ECP Variable: EPTCST
Definition: Transmission cost for interregional capacity additions
Units: \$ per Kilowatt
Alias: None
Level of Aggregation: Electricity Supply Region
Source: North American Electric Reliability Council
 "Coordinated Bulk Power Supply Report"
Subroutines: EP\$BDSP, EP\$INT, EP\$BRNW

ECP Variable: EPTIRGN
Definition: Import region for interregional capacity additions
Units: None
Alias: None
Level of Aggregation: Electricity Supply Region
Source: North American Electric Reliability Council
 "Coordinated Bulk Power Supply Report"
Subroutines: EP\$BLD, EP\$BDSP, EP\$INT, EP\$BRNW, EPO\$BILD

ECP Variable: EPTLOSS
Definition: Transmission loss factor for interregional capacity additions
Units: Fraction
Alias: TLOSS_{year}
Level of Aggregation: Electricity Supply Region
Source: OnLocation, Inc.
 "Draft Data Inputs for Implementation of ETT"
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Subroutines: EP\$BLD, EP\$BDSP, EP\$INT, EPO\$BILD

ECP Variable: EPTXRT
Definition: Net tax rate
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Tax Reform Act of 1986
Subroutines: EP\$PCL, EP\$RETRO, EP\$BDSP, EP\$INT, EP\$BRNW

ECP Variable: EPUCRE
Definition: Return on common equity for utilities
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Electricity and Finance Pricing (EFP) Submodule
Subroutines: EP\$BDSP, EP\$INT, EP\$BRNW, EPO\$BILD

ECP Variable: EPUFDT
Definition: Debt fraction for utilities
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Electricity and Finance Pricing (EFP) Submodule
Subroutines: EP\$BDSP, EP\$INT, EP\$BRNW, EPO\$BILD

ECP Variable: EPUFPE
Definition: Ratio of equity rate to rate of return for utilities
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Electricity and Finance Pricing (EFP) Submodule
Subroutines: EP\$BDSP, EP\$INT, EP\$BRNW, EPO\$BILD

ECP Variable: EPUIRT
Definition: Interest rate for utilities
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Electricity and Finance Pricing (EFP) Submodule
Subroutines: EP\$PCL, CRCONST, EP\$RETRO, EP\$BDSP, EP\$INT, EP\$BRNW, EPO\$BILD

ECP Variable: EPUROR
Definition: Rate of return (weighted average of debt and equity) for utilities
Units: Fraction
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Electricity and Finance Pricing (EFP) Submodule
Subroutines: EP\$PCL, CRCONST, EP\$RETRO, EP\$BDSP, EP\$INT, EP\$BRNW

ECP Variable: EPWIDTH
Definition: Width of vertical load slices
Units: Hours
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Load and Demand Side Management (LDSM) Submodule
Subroutines: EP\$ODSP, EP\$ORNW

ECP Variable: FIRSYR
Definition: Initial forecast year (i.e., 1 = 1990)
Units: None
Alias: None
Level of Aggregation: None
Source: Integrating Module
Subroutines: ECPOML

ECP Variable: MC_PGDP
Definition: Implicit price deflator (index of inflation)
Units: Scalar
Alias: None
Level of Aggregation: None
Source: Macroeconomic Module
Subroutines: ECPOML

ECP Variable: NEMMIO
Definition: Size of Workspace for EMM Matrix
Units: Kilobytes
Alias: None
Level of Aggregation: None
Source: Integrating Module
Subroutines: ECPOML

ECP Variable: UCISCF
Definition: Capacity factor for Canadian imports
Units: Fraction
Alias: ELCH_{yrsl}
Level of Aggregation: Electricity Supply Region
Source: Department of Energy
 "Northern Lights: The Economic and Practical Potential of Imported Power from
 Canada" (DOE/PE-0079)
Subroutines: EP\$ETT, EPO\$ETT

ECP Variable: UCIS CST
Definition: Cost for Canadian imports
Units: \$ per Thousand Kilowatthours
Alias: CBCH_{yrsl}
Level of Aggregation: Electricity Supply Region
Source: Department of Energy
 "Northern Lights: The Economic and Practical Potential of Imported Power from
 Canada" (DOE/PE-0079)
Subroutines: EP\$ETT, EPO\$ETT

ECP Variable: UCISFMW
Definition: Firm Canadian import capacity available
Units: Megawatts
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Department of Energy
 "Northern Lights: The Economic and Practical Potential of Imported Power from
 Canada" (DOE/PE-0079)
Subroutines: EP\$ETT

ECP Variable: UEITAJ
Definition: Interregional transfers
Units: Gigawatts
Alias: None
Level of Aggregation: Electricity Supply Region and Seasonal Period
Source: North American Electric Reliability Council
 "Coordinated Bulk Power Supply Report"
Subroutines: EP\$MRM, EP\$BLD, EP\$LOAD, EP\$BRNW

ECP Variable: UIALLW
Definition: Sulfur dioxide allowances allocated
Units: Thousand Tons
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Environmental Protection Agency
 "The National Allowance Data Base, Version 2.11, Technical Support Document"
 March 1993: Initial allocation of allowances
 Electricity Capacity Planning Submodule: Prior banking decisions
Subroutines: EP\$ALLOW, EPO\$BANK

ECP Variable: UPDLC
Definition: Capital cost learning factor for dispatchable technologies
Units: Fraction
Alias: None
Level of Aggregation: Dispatchable capacity types
Source: Assumed to be 0.0 (will be provided when New Technologies Submodule is linked)
Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: UPDOPT
Definition: Contingency factor for dispatchable technologies
Units: Fraction
Alias: None
Level of Aggregation: Dispatchable capacity types
Source: Argonne National Laboratories
 "Cost and Performance Database for New Generating Technologies"
Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: UPF759
Definition: Primary fuel code from Form EIA-759
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Source: Form EIA-759
Subroutines: EPO\$BILD

ECP Variable: UPF860
Definition: Primary fuel code from Form EIA-860
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Source: Form EIA-860
Subroutines: EPO\$BILD

ECP Variable: UPFUEL
Definition: Delivered fuel prices for year prior to beginning of forecast horizon
Units: Dollars per Million Btu
Alias: None
Level of Aggregation: Fuel Supply Regions
Source: Fuel Supply Modules
Subroutines: EPFLPRC

ECP Variable: UPGNPD
Definition: Inflation rate for converting to nominal dollars (equals MC_PGDP)
Units: Scalar
Alias: None
Level of Aggregation: None
Source: Macroeconomic Module
Subroutines: ECPOML, EP\$ETT, EP\$RETRO, EP\$BDSP, EPFLPRC, EP\$ODSP, EP\$INT, EP\$BRNW, EP\$ORNW

ECP Variable: UPICAPD
Definition: Real escalation rate for intermittent technologies
Units: Scalar
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting (Assumed to be 0.0)
Subroutines: EP\$INT, EPO\$BILD

ECP Variable: UPILC
Definition: Capital cost learning factor for intermittent technologies
Units: Fraction
Alias: None
Level of Aggregation: Intermittent capacity types
Source: Assumed to be 0.0 (will be provided when New Technologies Submodule is linked)
Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: UPIOPT
Definition: Contingency factor for intermittent technologies
Units: Fraction
Alias: None
Level of Aggregation: Intermittent technologies
Source: Electric Power Research Institute
 "Technical Assessment Guide, Electricity Supply-1993"
 June 1993
Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: UPM759
Definition: Prime mover (e.g., steam, combustion turbine) code from Form EIA-759
Units: Character
Alias: None
Level of Aggregation: None
Source: Form EIA-759
Subroutines: EPO\$BILD

ECP Variable: UPM860
Definition: Prime mover (e.g., steam, combustion turbine) code from Form EIA-860
Units: Character
Alias: None
Level of Aggregation: None
Source: Form EIA-860
Subroutines: EPO\$BILD

ECP Variable: UPPCAPD
Definition: Real escalation rate for dispatchable capacity types
Units: Scalar
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting (Assumed to be 0.0)
Subroutines: EP\$RETRO, EP\$BDSP, EPO\$BILD

ECP Variable: UPRCAPD
Definition: Real escalation rate for renewable (excluding intermittent) technologies
Units: Scalar
Alias: None
Level of Aggregation: None
Source: Office of Integrated Analysis and Forecasting (Assumed to be 0.0)
Subroutines: EP\$BRNW, EPO\$BILD

ECP Variable: UPRLC
Definition: Capital cost learning factor for renewable (excluding intermittent) technologies
Units: Fraction
Alias: None
Level of Aggregation: Renewable capacity types
Source: Assumed to be 0.0 (will be provided when New Technologies Submodule is linked)
Subroutines: EP\$BRNW, EPO\$BILD

ECP Variable: UPROPT
Definition: Contingency factor for renewable (excluding intermittent) technologies
Units: Fraction
Alias: None
Level of Aggregation: Renewable capacity types
Source: Electric Power Research Institute
 "Technical Assessment Guide, Electricity Supply-1993"
 June 1993
Subroutines: EP\$BDSP, EPO\$BILD

ECP Variable: UPSTYR
Definition: Initial forecast year for execution of Electricity Capacity Planning Submodule
Units: Year
Alias: None
Level of Aggregation: None
Source: User-specified
Subroutines: ELECP, ECPOML, EP\$BLD

ECP Variable: UPTCRT
Definition: Target coverage ratio for purchased capacity
Units: Fraction
Alias: None
Level of Aggregation: None
Source: OnLocation, Inc.
 "Establishing Constraints on Purchased Nonutility Generation"
 Deliverable 6, Task 92086, Contract DE-AC01-88EI21033
 March 1993
Subroutines: EP\$PCL, CRCONST, EP\$RETRO, EP\$BDSP, EP\$INT, EP\$BRNW

ECP Variable: URNCST
Definition: Maximum export capacity during summer season
Units: Gigawatts
Alias: EXP_{yr}
Level of Aggregation: Electricity Supply Regions
Source: North American Electric Reliability Council
 "Coordinated Bulk Power Supply Report"
Subroutines: EP\$ETT

ECP Variable: URNCWT
Definition: Maximum export capacity during winter season
Units: Gigawatts
Alias: EXP_y
Level of Aggregation: Electricity Supply Regions
Source: North American Electric Reliability Council
 "Coordinated Bulk Power Supply Report"
Subroutines: EP\$ETT

ECP Variable: USF759
Definition: Secondary fuel code from Form EIA-759
Units: Character
Alias: None
Level of Aggregation: None
Source: Form EIA-759
Subroutines: EPO\$BILD

ECP Variable: USF860
Definition: Secondary fuel code from Form EIA-860
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Source: Form EIA-860
Subroutines: EPO\$BILD

ECP Variable: WCAMSEL
Definition: Available capacity for Municipal Solid Waste
Units: Megawatts
Alias: RNWL_{nr}
Level of Aggregation: Electricity Supply Regions
Source: Renewable Fuels Module
Subroutines: EP\$BRNW

ECP Variable: WCASTEL
Definition: Available capacity for solar
Units: Megawatts
Alias: INTL_{ir}
Level of Aggregation: Electricity Supply Regions
Source: Renewable Fuels Module
Subroutines: EP\$INT

ECP Variable: WCAWIEL
Definition: Available capacity for wind
Units: Megawatts
Alias: INTL_r
Level of Aggregation: Electricity Supply Regions
Source: Renewable Fuels Module
Subroutines: EP\$INT

ECP Variable: XPCLELN
Definition: Expected coal price
Units: Dollars per Million Btu
Alias: None
Level of Aggregation: Electricity Supply Region
Source: Office of Integrated Analysis and Forecasting
Subroutines: EPFLPRC

ECP Variable: XPCLEL
Definition: Expected coal price
Units: Dollars per Million Btu
Alias: None
Level of Aggregation: Census Division
Source: Integrating Module
Subroutines: EPFLPRC

ECP Variable: XPDSEL
Definition: Expected distillate fuel oil price
Units: Dollars per Million Btu
Alias: None
Level of Aggregation: Census Division
Source: Integrating Module
Subroutines: EPFLPRC

ECP Variable: XPGFEL
Definition: Expected firm natural gas price
Units: Dollars per Million Btu
Alias: None
Level of Aggregation: Census Division
Source: Integrating Module
Subroutines: EPFLPRC

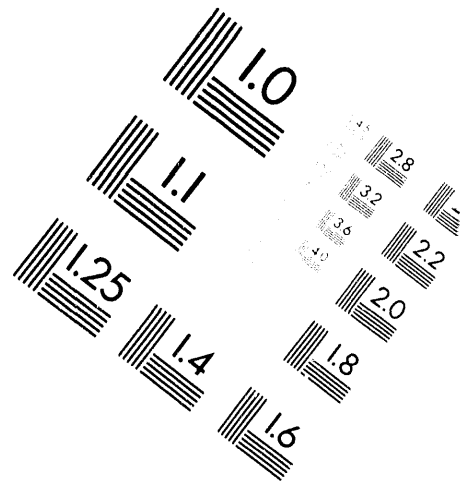
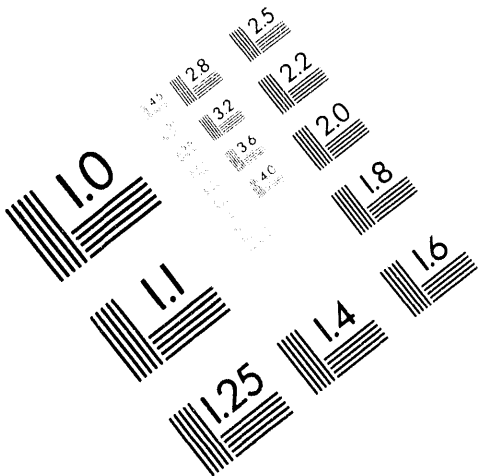


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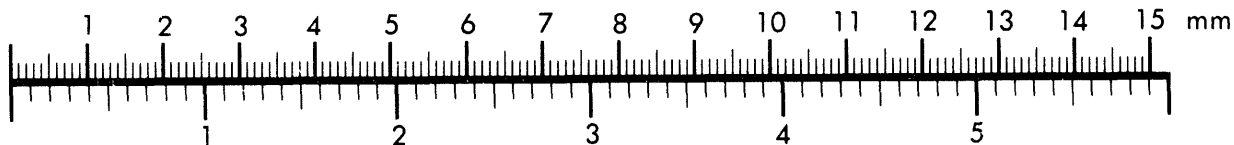
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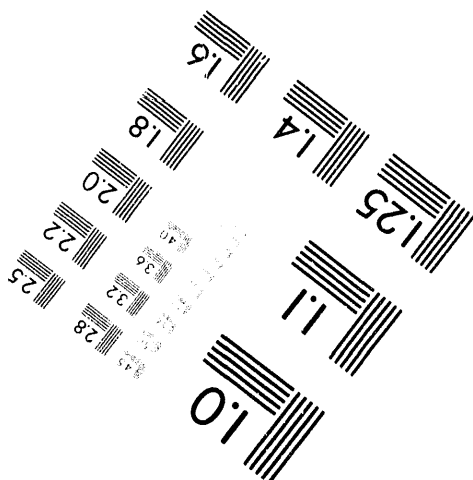
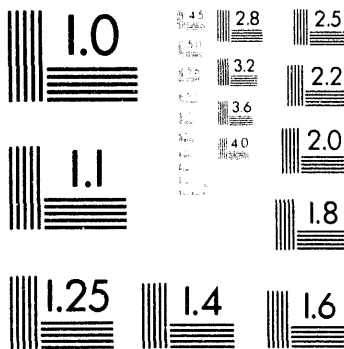
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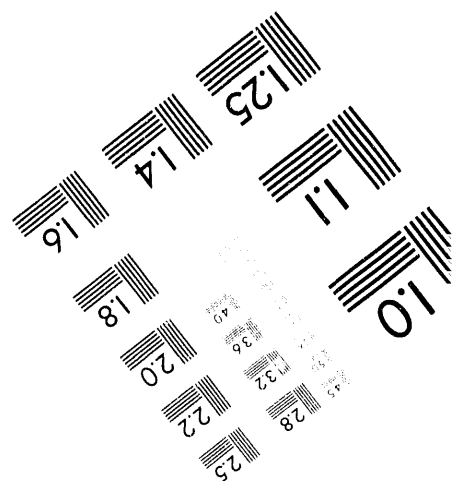
Centimeter



Inches



MANUFACTURED TO AIIM STANDARDS
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ECP Variable: XPGIEL
Definition: Expected interruptible natural gas price
Units: Dollars per Million Btu
Alias: None
Level of Aggregation: Census Division
Source: Integrating Module
Subroutines: EPFLPRC

ECP Variable: XPRHEL
Definition: Expected high-sulfur residual fuel oil price
Units: Dollars per Million Btu
Alias: None
Level of Aggregation: Census Division
Source: Integrating Module
Subroutines: EPFLPRC

ECP Variable: XPRLEL
Definition: Expected low-sulfur residual fuel oil price
Units: Dollars per Million Btu
Alias: None
Level of Aggregation: Census Division
Source: Integrating Module
Subroutines: EPFLPRC

ECP Variable: XPUREL
Definition: Expected uranium price
Units: Dollars per Million Btu
Alias: None
Level of Aggregation: Census Division
Source: Integrating Module
Subroutines: EPFLPRC

OUTPUT VARIABLES

ECP Variable: BIOBLDS
Definition: Cumulative Biomass Additions
Units: Megawatts
Alias: RNW_{ymo}
Level of Aggregation: Electricity Supply Region
Subroutines: ELECP, EP\$BRNW, EPO\$BILD

ECP Variable: ECLCAP
Definition: Total coal-fired capacity by coal region and year, including existing units, planned and unplanned additions, and scheduled retirements
Units: Megawatts
Alias: None
Level of Aggregation: Coal Distribution Submodule (CDS) Regions
Subroutines: EPO\$BILD

ECP Variable: EPALLOW
Definition: Current year allowance cost for sulfur dioxide
Units: \$ per Ton
Alias: None
Level of Aggregation: National
Subroutines: EPO\$BANK

ECP Variable: EPAVOID
Definition: Avoided cost of electricity
Units: Million \$ per Gigawatt
Alias: None
Level of Aggregation: Electricity Supply Region
Subroutines: EP\$AVOID

ECP Variable: EPBANK
Definition: Current-year banking decision for sulfur dioxide emissions allowances
Units: Million Tons
Alias: BNK_{yn}
Level of Aggregation: National
Subroutines: EPO\$BANK

ECP Variable: EPRMRGN
Definition: Avoided cost (dual-value) for reserve margin constraint
Units: \$ per Kilowatt
Alias: None
Level of Aggregation: Electricity Supply Region
Subroutines: EPO\$AVOID

ECP Variable: UCANBLD
Definition: Canadian build decisions
Units: Gigawatts
Alias: BCH_{ys}
Level of Aggregation: Electricity Supply Region
Subroutines: EPO\$ETT

ECP Variable: WCFLAG
Definition: Code to identify source of average capacity factor
Units: Scalar (4=Electricity Capacity Planning Submodule)
Alias: None
Level of Aggregation: Dispatchable and renewable technologies
Subroutines: EPO\$BILD

ECP Variable: WCOMB
Definition: Code to indicate if units are grouped or not for dispatching
Units: Scalar (0=not grouped, 1=grouped)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WCPLUS
Definition: Code to identify plant location
Units: Character
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WC_NP
Definition: Nameplate capacity of capacity planning decisions
Units: Megawatts
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WC_SUM
Definition: Net summer capability of capacity planning decisions
Units: Megawatts
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WC_TOT
Definition: Total nameplate capacity of capacity planning decisions
Units: Megawatts
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WC_WIN
Definition: Net winter capability of capacity planning decisions
Units: Megawatts
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WEFPT
Definition: Financial asset type code for capacity planning decisions
Units: Character
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WFLT
Definition: Fuel type codes for capacity planning decisions for use in Electricity Fuel Dispatching Submodule
Units: Character
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WFOWN
Definition: Ownership type for capacity planning decisions
Units: Character
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WHFLAG
Definition: Code to identify source of heatrate
Units: Scalar (4=Electricity Capacity Planning Submodule)
Alias: None
Level of Aggregation: Dispatchable and renewable technologies
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WMKWH
Definition: Weighted average cost of electricity
Units: Dollars per Thousand Kilowatthours
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD

ECP Variable: WMKWH1
Definition: Average cost of electricity using primary fuel
Units: Dollars per Thousand Kilowatthours
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD

ECP Variable: WMKWH2
Type: Output
Definition: Average cost of electricity using secondary fuel
Units: Dollars per Thousand Kilowatthours
Alias: None
Level of Aggregation: None
Source:
Subroutines: EPO\$BILD

ECP Variable: WNEMST
Definition: Plant type code for capacity planning decisions
Units: Character
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WNEWGRP
Definition: Code to identify plant group for new unplanned capacity additions
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WNGRPS
Definition: Number of new plant groups
Units: Scalar
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WO_RMO
Definition: Month of completion for retrofitting existing capacity with scrubbers (i.e., existing unscrubbed unit is retired and new scrubbed unit begins operation)
Units: Month (e.g., 1=January)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$RETRO

ECP Variable: WO_RYR
Definition: Year of completion for retrofitting existing capacity with scrubbers (i.e., existing unscrubbed unit is retired and new scrubbed unit begins operation)
Units: Year (e.g., 1995)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$RETRO

ECP Variable: WPCST
Definition: Overnight capital cost of build or retrofit decision
Units: Dollars per Kilowatt
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WPF759
Definition: Primary fuel code corresponding to Form EIA-759 for capacity addition
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WPF860
Definition: Primary fuel code corresponding to Form EIA-860
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WPFshr
Definition: Maximum fuel share for primary fuel
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WPM759
Definition: Prime mover code (e.g., steam) corresponding to Form EIA-759 for capacity addition
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WPM860
Definition: Prime mover code (e.g., steam) corresponding to Form EIA-860
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WS2ACT
Definition: Actual sulfur dioxide emission rate (assumed to equal standard for new units)
Units: Pounds per Million Btu
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WS2STD
Definition: Sulfur dioxide emission standard
Units: Pounds per Million Btu
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WSCBEF
Definition: Sulfur dioxide removal rate for scrubbers retrofits
Units: Fraction
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WSCBTP
Definition: Code to indicate scrubber is a retrofit
Units: Character
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WSCBYR
Definition: Initial operating date for existing capacity retrofitted with scrubber
Units: Year
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WSF759
Definition: Secondary fuel code corresponding to Form EIA-759 for capacity addition
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WSF860
Definition: Secondary fuel code corresponding to Form EIA-860
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WSFSHR
Definition: Maximum fuel share for secondary fuel
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WSTAT1
Definition: Current status code
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WSTAT2
Definition: Future status code
Units: Character
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD

ECP Variable: WTYPE
Definition: Code to indicate type of new unit
Units: Scalar (0=renewable, 1=nonrenewable)
Alias: None
Level of Aggregation: Capacity types (dispatchable, renewable, and intermittent)
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: WVIN
Definition: Code to indicate type of new unit
Units: Scalar (3=capacity expansion decision, 9=retrofit decision)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: W_CF
Definition: Average capacity factor for new capacity
Units: Fraction
Alias: None
Level of Aggregation: Renewable technologies
Subroutines: EPO\$BILD

ECP Variable: W_RMO
Definition: Month that capacity addition or retrofitted unit will be retired
Units: Month (e.g., 1=January)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: W_RYR
Definition: Year that capacity addition or retrofitted unit will be retired
Units: Year (e.g., 1995)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: W_SMO
Definition: Month that capacity addition or retrofitted unit will begin operation
Units: Month (e.g., 1=January)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: W_SYR
Definition: Year that capacity addition or retrofitted unit will begin operation
Units: Year (e.g., 1995)
Alias: None
Level of Aggregation: None
Subroutines: EPO\$BILD, EPO\$RETRO

ECP Variable: ZTIMPD
Definition: Cost of firm Canadian power imports
Units: Millions of \$
Alias: None
Level of Aggregation: Electricity Supply Region
Subroutines: EPO\$ETT

Appendix B

ELECTRICITY CAPACITY PLANNING (ECP) SUBMODULE SUBROUTINES AND FUNCTIONS

This appendix contains a description of the FORTRAN subroutines of the ECP, including a mathematical specification of the equations that derive the coefficients of the objective function and constraint matrix of the LP model.

SUBROUTINE: ELECP

Description: This subroutine is the main controlling module of the ECP. ELECP initializes variables and checks a user-specified switch that determines if the ECP will be executed. If the ECP is turned off, then the capacity planning decisions from a previous NEMS run are used.

Called By: UTIL
Calls: ECPOML

Equations: NONE

SUBROUTINE: ECPOML

Description: ECPOML initializes the LP database and sets up the starting matrix using OML subroutines. Next, it calls a series of subroutines that compute the revisions to objective function coefficients, row/column intersections, and right-hand sides for the constraint matrix. ECPOML then executes OML subroutines to load the matrix and starting basis, solve the model, and retrieve the solution.

Called By: ELECP
Calls: EP\$ALLOW,EP\$ETT,GETBLD,EP\$BLD,EP\$PCL,EPFLPRC,
 GETEIJ,EP\$MRM,EP\$LOAD,EP\$RETRO,EP\$BDSP,EP\$BRNW,
 EP\$ODSP,EP\$ORNW,EP\$INT,EP\$DSM,EPO\$BANK,EPO\$ETT,
 EPO\$AVOID,EPO\$BILD,EPO\$RETRO,STRBOUT

Equations: NONE

SUBROUTINE: EP\$ALLOW

Description: EP\$ALLOW revises the right-hand side of the emissions constraints and sets upper bounds on the allowance banking columns for each year of the planning horizon. For sulfur dioxide (SO₂), the limit corresponds to the sum of the emissions allowances allocated in accordance with the CAAA and is adjusted as a result of prior banking decisions. The limit is implemented as a national constraint since allowances can be traded. This subroutine calls GETSO2, which obtains the SO₂ allowances from an EMM input file.

Called By: ECPOML
Calls: GETSO2

Equations: Revise the RHS value of the SO₂ Emissions Constraints for each year y. (Million Tons)

$$ALW_y \leq UIALLW_y * 0.001$$

for y = 1995, 1996, . . . , 2010.

$$ALW_y \leq 22000.0$$

for y = 1990, 1991, 1992, 1993, 1994.

where: UIALLW_y = Initial SO₂ Allowances for year y. (Thousand Tons)

Revise the Upper Bound on the Allowance Banking Columns (ALW_{ynt}) for each year y. (Million Tons)

$$BNK_{ynt} \leq 50000.0$$

for y = 1995, 1996, . . . , 2010 and n LE last year in planning horizon.

$$BNK_{ynt} = 0.0$$

for y = 1990, 1991, 1992, 1993, 1994

where: n = the year that allowances are banked to (y+1)
t = pollutant SO₂

SUBROUTINE: EP\$ETT

Description: EP\$ETT sets up the interregional transmission constraints and incorporates limits on imports from new Canadian hydroelectric projects for each region for all years in the planning horizon. The corresponding contributions to reserve margin requirements are also included. EP\$ETT calls GETEIJ, which obtains transmission and trade data from an EMM input file.

Called By: ECPOML
Calls: GETEIJ

Equations: Revise the RHS value of the interregional transmission constraints for each region r and year y (Gigawatts).

$$EXP_{yr} = \text{MAX}(URNCST_{yr}, URNCWT_{yr})$$

where: $URNCST_{yr}$ = Summer Exports for year y, region r. (Gigawatt)
 $URNCWT_{yr}$ = Winter Exports for year y, region r. (Gigawatt)

Revise the matrix coefficients of the build canadian hydro capacity vectors (BCH_{yrs}) for each import region r, year y and canadian import supply step s.

Column Upper Bound (Gigawatts):

$$BCH_{yrs} \leq UCI\$FMW_{yrs} * 0.001$$

where: $UCI\$FMW_{yrs}$ = Firm canadian supply capacity available for year y, region r and canadian supply step s. (Megawatts)

Objective Function Coefficient (Million \$ / Gigawatt):

$$VALUE = UCI\$CST_{yrs} * UCI\$CF_{yrs} * UPGNPD_y * 0.0876$$

If last year of planning horizon

$$VALUE = VALUE / CRF(EPDSCRT, (ECP\$FPH - ECP\$XPH))$$

Endif

$$CBCH_{yrs} = VALUE * PWF(EPDSCRT, YEAR)$$

where: $UCI\$CST_{yrs}$ = Variable operating cost for canadian hydroelectric capacity for year y, import region r and canadian supply step s. (\$/Thousand Kilowatthours)

$UCI\$CF_{yrs}$ = Maximum Capacity Factor for canadian hydroelectric capacity for year y, import region r and canadian supply step s. (Percent)

$UPGNPD_y$ = Inflation rate for converting to nominal dollars.

$EPDSCRT$ = Utility discount rate (nominal, tax-adjusted rate of return)

$ECP\$FPH$ = Length of Full Planning Horizon (30 Years)

$ECP\$XPH$ = Length of Explicit Planning Horizon (6 Years)

CRF = Capital Recovery Factor Function

PWF = Present Worth Factor Function

Reserve Margin Coefficient (Fraction):

$$RMC_{yrc} = UCI\$CF_{yrs} * 0.01$$

where: $UCI\$CF_{yrs}$ = Maximum Capacity Factor for canadian hydroelectric capacity for year y, import region r and canadian supply step s. (Percent)

Purchased Capacity Coefficient (Million \$/Gigawatt):

$$PPCC_{yrs} = CBCH_{yrs}$$

The contribution to the purchase capacity is set to the objective value function calculated above.

Load Requirements Row Coefficient (Fraction):

$$ELR_{yrl} = UCI\$CF_{yrs} * 0.01$$

SUBROUTINE: EP\$MRM

Description: This subroutine determines the minimum capacity requirements for each electricity supply region in each year of the planning horizon. The total available capacity must exceed the expected peak demand by at least the minimum reserve margin, accounting for imports/exports of electricity during the peak load segment. This quantity is represented as the right-hand side of the reserve margin constraint.

Called By: ECPOML

Equations: The total capacity requirement (Gigawatt) for each region r and year y is given by

$$RMQ_{yr} = EPPEAK_{yr} * (1 + EEMRM_r) + UEITAJ_{yrs}.$$

where: $EPPEAK_{yr}$ = Peak Load for region r year y . (Gigawatt)
 $EEMRM_r$ = Minimum Reserve Margin Requirement for region r . (Fraction)
 $UEITAJ_{yrs}$ = Interregional transfers for year y region r and season s (the season in which the peak load occurs for region r).

SUBROUTINE: EP\$BLD

Description: EP\$BLD revises the right-hand sides and row/column intersections of constraints that restrict capacity additions over and above the reserve margin requirement. This 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. EP\$BLD also calls GETEIJ in order to incorporate contributions to the reserve margin requirement of plants built in one region to serve another.

Called By: ECPOML
Calls: GETEIJ

Equations: Revise the RHS value of the dispatchable capacity build constraints for each region r and year y (Gigawatt).

$$CAPL_{yr} = EPPPEAK_{yr} \cdot (1 + EPMRM_r) + UEITAJ_{sr} - \sum_c EPPCAP_{yrc} \cdot .001 - \sum_n EPRCAP_{ym} \cdot .001$$

where: EPPEAK_{yr} = Peak Load for region r year y. (Gigawatt)
EEMRM_r = Minimum Reserve Margin Requirement for region r. (Fraction)
UEITAJ_{yr} = Interregional transfers for year y region r and season s (the season in which the peak load occurs for region r).
EPPCAP_{yrc} = Existing Capacity for dispatchable capacity c in region r year y. (Megawatt)
EPRCAP_{ym} = Existing Capacity for renewable dispatchable capacity n in region r year y. (Megawatt)

Revise the matrix coefficients of the dispatchable capacity build constraints for each region r and year j.

Build new dispatchable capacity (BLD_{yrc}): 1.0

Build dispatchable capacity for another region (BDI_{yrg}): EPTLOSS_{yrg}

Build new renewable capacity (RNW_{ym}): EPRCCR_{ym}

Build renewable capacity for another region (BRI_{yrg}): EPRCCR_{ym} * EPTLOSS_{yrg}

for j = (y + construction lead time for dispatchable capacity type c or renewable dispatchable capacity type n, ECP\$XPH)

where: EPTLOSS_{yrg} = Transmission loss factor for interregional capacity additions from region r to region g in year y. (Fraction)
EPRCCR_{ym} = Capacity credit for renewable capacity type n in region r year y. (Fraction)
ECP\$XPH = Length of explicit planning horizon. (6 Years)

SUBROUTINE: EP\$PCL

Description: EP\$PCL places limits on the amount of capacity that can be purchased from nonutility suppliers. In a given region, capacity additions by nonutility suppliers are allowed as long as 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.

Called By: ECPOML

Equations: Revise RHS value of the purchased capacity constraints for each region r and year y (Million \$).

$$B = (EPUROR_{yr} * EPUFPE_{yr}) / (1.0 - EPTXRT_{yr}) \quad (\text{Equity Component})$$

$$D = (EPUFDT_{yr} * EPUIRT_{yr}) \quad (\text{Debt Component})$$

$$VALUE_{yr} = EPRTBS_{yr} * COEFCR(B,D,UPTCRT)$$

$$VALUE_{yr} = \text{MAX}(0.0, VALUE_{yr})$$

For first year of planning horizon:

$$VALUE_{yr} = VALUE_{yr}$$

For second through last year of planning horizon:

$$VALUE_{yr} = VALUE_{yr} * (1.0 - .03)$$

where: $EPUROR_{yr}$ = Utility Rate of Return for region r year y.

$EPUFPE_{yr}$ = Taxable portion of utility rate of return for region r year y. (Fraction)

$EPTXRT_{yr}$ = Net Tax Rate for region r year y.

$EPUFDT_{yr}$ = Utility debt fraction for region r year y. (Fraction)

$EPUIRT_{yr}$ = Utility interest rate for region r year y.

$EPRTBS_{yr}$ = Initial utility rate base for region r year y.

$UPTCRT$ = Target coverage ratio for purchased capacity in region r year y.

$COEFCR$ = function that calculates the excess dollars available to 'cover' purchase power payments as though they were debt payments.

SUBROUTINE: EP\$LOAD

Description: EP\$LOAD revises the right-hand side of the load requirements constraints, which insure that sufficient generating capacity is allocated or DSM programs are implemented to satisfy both the capacity and energy needs in each region and year of the planning horizon. These right-hand side values are computed for each of the seasonal/time-of-day load segments in the ECP.

Called By: ECPOML

Equations: Revise the RHS value of the Electricity load requirement constraints for each region r, year y and vertical load step l (Gigawatt).

$$ELC_{yrl} = EPHGHT_{yrl} + UEITAJ_{yrs}$$

where: $EPHGHT_{yrl}$ = Height of the vertical load segment l for region r year y. (Gigawatt)
 $UEITAJ_{yrs}$ = Interregional transfers for year y region r and season s (the season in which the load segment l occurs for region r). (Gigawatt)

SUBROUTINE: EP\$RETRO

Description: EP\$RETRO revises the right-hand side of the constraints that limits scrubber retrofits to units that satisfy prespecified criteria for size and age and adjusting for prior retrofit decisions. This subroutine also computes the cost coefficients for retrofit decisions. EP\$RETRO calls EPINCST to calculate the installed cost of a generating unit, and EPNBLD to compute the present value of the revenue requirements for installing retrofits. This subroutine also adjusts the row/column coefficients in the capacity balance rows, which shift capacity from unscrubbed to scrubbed to reflect the resulting lower emission rates.

Called By: ECPOML
Calls: EPNBLD,EPINCST

Equations: Revise the RHS value of the Retrofit constraints for each unscrubbed capacity type c, retrofit cluster u and region r (Gigawatt).

$$FGDL_{rcu} = EPSCAP_{yrcu} * .001$$

where: $EPSCAP_{yrcu}$ = Upper limit on existing capacity c that can be retrofitted in region r year r and retrofit cluster code u. (Megawatt)

Revise the matrix coefficients of the retrofit unscrubbed coal capacity vectors (FGD_{yrcku}) for each unscrubbed capacity type c, scrubbed capacity type k, retrofit cluster u, region r, and year y.

Objective Function Coefficient (Million \$/Gigawatt):

```
OVRNST = EPSOVRyrcku
CALL EPINCST(MNUMYR,ECP$XPH,ECP$FPH,EPSCLTyrc,CURIYR,y,
              OVRNST,EPSCPRyrc,UPPCAPDc,UPGNPDy,EPUIRTyr,
              EPUFDTyr,EPURORyr,TXBOOK,FNBOOK)
URATIO = TXBOOK / FNBOOK
CAPUNSTL = FNBOOK
CALL EPNBLD(EPURORyr,EPDSCRT,URATIO,EPUFPEyr,EPSELFyrc,EPSELFyrc,
            EPTXRTyr,EPSELFyrc,CAPUTIL)
CFGDyrcku = ((CAPUNSTL * CAPUTIL) / CRF(EPDSCRT,IFPH2)) *
            PWF(EPDSCRT,OLYR)
```

where: $EPSOVR_{yrcku}$ = Overnight capital cost for retrofitting existing capacity with scrubbers. (\$/Kilowatt)
MNUMYR = Number of years in NEMS forecast horizon (29 years).
ECP\$FPH = Length of Full Planning Horizon (30 Years).
ECP\$XPH = Length of Explicit Planning Horizon (6 Years).
EPSCLT_{yrc} = Construction lead time for installing retrofits on existing dispatchable capacity type c in region r year y. (Years)
CURIYR = Current forecast year of NEMS run (1 = 1990)
EPSCPR_{yrc} = Construction profile for retrofitting dispatchable capacity type c in region r year y. (Fraction)
UPPCAPD_c = Real capital cost deflator for dispatchable capacity type c. (Fraction)
UPGNPD_y = Inflation rate for converting to nominal dollars
EPUIRT_{yr} = Utility Interest Rate for region r year y.
EPUFDT_{yr} = Utility debt fraction for region r year y. (Fraction)

EPUROR _{yr}	= Utility Rate of Return for region r year y.
TXBOOK	= Tax basis installed costs returned from EPINCST
FNBOOK	= Book value installed costs returned from EPINCST
EPDSCRT	= Utility discount rate (nominal,tax-adjusted rate of return)
EPUFPE _{yr}	= Taxable portion of utility rate of return in region r year y. (Fraction)
EPSELF _{yr}	= Economic life for scrubber retrofits on existing capacity c in region r year y. (Years)
EPTXRT _{yr}	= Net Tax Rate for region r year y.
CAPUTIL	= Fixed charged factor to transform the installed book value into a fixed nominal annuity returned from EPNBLD.
CRF	= Capital Recovery Factor Function
PWF	= Present Worth Factor Function
OLYR	= On line year for retrofit (y + EPSCLT _{yr})
IFPH2	= ECP\$FPH - OLYR

Reserve Margin Row Coefficient (Fraction):

$$VALUE_{jrcku} = (EPSCPEN_{yrku} - 1.0)$$

for j = OLYR,ECP\$XPH

where: EPSCPEN_{yrku} = Capacity penalty for operating scrubbed capacity type k, retrofit cluster u in region r, and year y. (Fraction)

Purchased Capacity Row Coefficient (Million \$/Gigawatt):

$$VALUE_{jrcku} = CAPUNSTL * CRCONST(UPTCRT,EPUFPE_{yr},EPUROR_{yr},EPUFDT_{yr},EPUIRT_{yr},EPTXRT_{yr},EPSELF_{yr},EPSELF_{yr},URATIO,PYR)$$

for j = OLYR,ECP\$XPH

where: CRCONST = Function that calculates a scalar that represents the excess earnings available to utility to support its fixed commitments to purchased power contracts per dollar invested in rate base.

UPTCRT = Target coverage ratio.

PYR = j - OLYR + 1

Capacity Balance Row Coefficient for Scrubbed Capacity Type k (Fraction):

$$VALUE_{jrcku} = -EPSCPEN_{yrcku}$$

for j = OLYR,ECP\$XPH

SUBROUTINE: EP\$BDSP

Description: EP\$BDSP revises the upper bounds on existing dispatchable capacity vectors for each year of the current planning horizon. However, EP\$BDSP's primary function is the revision of the objective function value for the build vectors of each dispatchable capacity type. For each capacity type there are up to four build types as defined by the combination of ownership (utility versus non-utility) and end use market (own use versus export). The choice of ownership is reflected in both the cost of financing and the resulting impact on the financial health of the electric utility which will use the new generation capacity. Building for export includes the additional cost of transmission capacity required to deliver electricity to the import region, as well as, a decrement to the available capacity to capture the additional transmission losses. The objective function value is the present value at the beginning of the planning horizon of all electric utility cash flows including fixed operations and maintenance expenses required to pay for one unit of generation capacity and the associated increment of transmission capacity.

Several financial functions are used to produce the objective function value. The PVV function determines the present value of a vector of numbers. The PWF function calculates a factor that equates a future value to present value terms. The EPINCST function converts an overnight cost, a construction profile and the cost of capital into an installed cost on both a book and a tax basis. For utility builds, EPNBLD function determines the fixed charge factor to transform the installed book value into a fixed nominal annuity. Similarly, EPCNBLD function determines the fixed charge factor for non-utility builds. The CRF function returns an annuity factor associated with a discount rate and a term. Consequently, the reciprocal of the CRF function converts an annuity over a given term to a present value.

This subroutine also computes the contribution/decrement to the purchased capacity constraint for utility/non-utility build vectors, respectfully. For non-utility vectors the decrement to the purchased capacity constraint is the capital cost annuity. For utility vectors, the CRCONST function calculates a factor relating excess earnings available to support purchased power contracts to an investment in rate base and thus defines the contribution to the purchased capacity constraint.

Called By: ECPOML
Calls: EPNBLD,EPINCST,EPCNBLD

Equations: Revise upper bound on the existing capacity vectors (EXC_{yrc}) for each dispatchable capacity type c, region r and year y (Gigawatt).

$$EXC_{yrc} \leq EPPCAP_{yrc} * .001$$

where: $EPPCAP_{yrc}$ = Existing Capacity for dispatchable capacity c in region r year y.
(Megawatt)

Calculate present value of fixed o&m costs at OLYR (on line year for plant build - construction lead time + y.

$$FOM_j = (EPPFOM_{yrc} + EPCFOM_{yrc}) * UPGNPD_{(j+curlyr+olyr-2)}$$

for $j = 1, IFPH2$

$$PV\$FOM = PVV(FOM,ECP\$FPH,IFPH2,EPDSCRT) *$$

PWF(EPDSCRT,OLYR)

where: EPPFOM_{yr_c} = Fixed operating and maintenance costs for dispatchable capacity type c in region r year y. (\$/Kilowatt)
 EPCFOM_{yr_c} = Fixed operating and maintenance transmission costs for dispatchable capacity type c in region r year y. (\$/Kilowatt)
 UPGNPD_y = Inflation rate for converting to nominal dollars
 OLYR = On line year for capacity type c build.
 IFPH2 = ECP\$FPH - OLYR + 1
 ECP\$FPH = Length of Full Planning Horizon (30 Years)
 EPDSCRT = Utility discount rate (nominal,tax-adjusted rate of return)
 PVV = function that calculates the present value of a vector of numbers.
 PWF = Present Worth Factor Function

Revise matrix coefficients of the utility builds (o=U)

Revise matrix coefficients of the build dispatchable capacity vectors (BLD_{yrco}) for each dispatchable capacity type c, region r and year y.

Objective Function Coefficient (Million \$/Gigawatt):

OVRCST = EPPOVR_{yr_c} * UPDOPT_c * UPDLC_c
 CALL EPINCST(MNUMYR,ECP\$XPH,ECP\$FPH,EPPCLT_{yr_c},CURIYR,y,
 OVRCST,EPPCPR_{yr_c},UPPCAPD_c,UPGNPD_y,EPUIRT_{yr},
 EPUFDT_{yr},EPUROR_{yr},TXBOOK,FNBOOK)
 URATIO = TXBOOK/FNBOOK
 CAPUNSTL = FNBOOK
 CALL EPNBLD(EPUROR_{yr},EPDSCRT,URATIO,EPUFPE_{yr},EPPELF_{yr_c},EPPTLF_{yr_c},
 EPTXRT_{yr},EPPUCLF_{yr_c},CAPUTIL)
 TRANS = EPCOVR_{yr_c} * UPGNPD_y * EPCCRF_{yr_c}
 OBJVAL = ((CAPUNSTL * CAPUTIL + TRANS) / (CRF(EPDSCRT,IFPH2) *
 PWF(EPDSCRT,OLYR)
 CBLD_{yrco} = OBJVAL + PV\$FOM

where: EPPOVR_{yr_c} = Overnight capital cost for dispatchable capacity type c in region r year y. (\$/Kilowatt)
 UPDOPT_c = Technical optimism factor for dispatchable capacity type c.
 UPDLC_c = Learning Curve factor for dispatchable capacity type c.
 MNUMYR = Current year of NEMS run (1990 - 2010)
 ECP\$FPH = Length of Full Planning Horizon (30 Years)
 ECP\$XPH = Length of Explicit Planning Horizon (6 Years)
 EPPCLT_{yr_c} = Construction lead time for dispatchable capacity type c in region r year y. (Years)
 CURIYR = Current forecast year of NEMS run (1 = 1990)
 EPPCPR_{yr_c} = Construction profile for dispatchable capacity type c in region r year y. (Fraction)
 UPPCAPD_c = Real capital cost deflator for dispatchable capacity type c.
 EPUIRT_{yr} = Utility Interest Rate in region r year y.
 EPUFDT_{yr} = Utility debt fraction for region r year y. (Fraction)
 EPUROR_{yr} = Utility Rate of Return for region r year y.

TXBOOK	= Tax basis installed costs returned from EPINCST
FNBOOK	= Book value installed costs returned from EPINCST
EPUFPE _{yr}	= Taxable portion of utility rate of return in region r year y. (Fraction)
EPPELF _{yr}	= Economic life for dispatchable capacity type c in region r year y. (Years)
EPPTLF _{yr}	= Tax life for dispatchable capacity type c in region r year y. (Years)
EPPUCLF _{yr}	= Contract life for utility dispatchable capacity type c in region r year y. (Years)
EPTXRT _{yr}	= Net Tax Rate for region r year y.
CAPUTIL	= Fixed charged factor to transform the installed book value into a fixed nominal annuity returned from EPNBLD.
EPCOVR _{yr}	= Overnight capital costs for transmissions for dispatchable capacity type c in region r year y. (\$/Kilowatt)
UPGNPD _y	= Inflation rate for converting to nominal dollars
EPCCRF _{yr}	= Fixed charge factor for transmissions for dispatchable capacity type c in region r year y. (Fraction)
CRF	= Capital Recovery Factor Function
PWF	= Present Worth Factor Function

Purchased Capacity Row Coefficient (Million \$/Gigawatt):

$$VALUE_{yrj} = CAPUNSTL * CRCONST(UPTCRT, EPUFPE_{yr}, EPUROR_{yr}, EPUFDT_{yr}, EPUIRT_{yr}, EPTXRT_{yr}, EPPTLF_{yr}, EPPELF_{yr}, URATIO, PYR)$$

for j = OLYR, ECP\$XPH

where: CRCONST = Function that calculates a scalar that represents the excess earnings available to utility to support its fixed commitments to purchased power contracts per dollar invested in rate base.

UPTCRT = Target coverage ratio.

PYR = j - OLYR + 1.

Revise matrix coefficients of the build dispatchable capacity for another region vectors (BDI_{yrj}) for each dispatchable capacity type c, region r, import region g, and year y.

Objective Function Coefficient (Million \$/Gigawatt):

$$\begin{aligned} TRANS &= EPTCST_{yr} * UPGNPD_y * EPTCRF_{yr} \\ OBJVAL &= ((CAPUNSTL * CAPUTIL + TRANS) / (CRF(EPDSCRT, IFPH2) * PWF(EPDSCRT, OLYR)) \\ CBDI_{yrj} &= OBJVAL + PV\$FOM \end{aligned}$$

where: EPTCST_{yr} = Transmission costs for interregional capacity additions from region r to region g in year y. (\$/Kilowatt)

EPTCRF_{yr} = Transmission annuity factor for interregional capacity additions from region r to region g in year y. (Fraction)

Purchased Capacity Row (for import region) Coefficient (Million \$/Gigawatt):

$$\text{VALUE}_{ygc} = \text{CAPUNSTL} * \text{CRCONST}(\text{UPTCRT}, \text{EPUFPE}_{yr}, \text{EPUROR}_{yr}, \text{EPUFDT}_{yr}, \text{EPUIRT}_{yr}, \text{EPTXRT}_{yr}, \text{EPPTLF}_{yrc}, \text{EPPELF}_{yrc}, \text{URATIO}, \text{PYR})$$

for j = OLYR, ECP\$XPH

Reserve Margin Row (for import region) Coefficient (Fraction):

$$\text{VALUE}_{jgc} = \text{EPTLOSS}_{yrg}$$

for j = OLYR, ECP\$XPH

where: EPTLOSS_{yrg} = Transmission loss factor for interregional capacity additions from region r to region g in year y. (Fraction)

Capacity Balance Row (for import region) Coefficient (Fraction):

$$\text{VALUE}_{jgc} = - \text{EPTLOSS}_{yrg}$$

for j = OLYR, ECP\$XPH

Revise matrix coefficients of the non-utility builds (o=N)

Revise matrix coefficients of the build dispatchable capacity vectors (BLD_{yrc}) for each dispatchable capacity type c, region r and year y.

Objective Function Coefficient (Million \$/Gigawatt):

$$\begin{aligned} \text{EWGROE} &= \text{EPUCRE}_{yr} + \text{EPNRPRM}_{yr} \\ \text{EWGINT} &= \text{EPUIRT}_{yr} + \text{EPNIPRM}_{yr} \\ \text{EWGROR} &= \text{EWGROE} * (1.0 - \text{EPNFDT}_{yr}) + \text{EWGINT} * \text{EPNFDT}_{yr} \\ \text{OVR CST} &= \text{EPPOVR}_{yrc} * \text{UPDOPT}_c * \text{UPDLC}_c \\ \text{CALL EPINCST} &(\text{MNUMYR}, \text{ECP\$XPH}, \text{ECP\$FPH}, \text{EPPCLT}_{yrc}, \text{CURIYR}, y, \\ &\quad \text{OVR CST}, \text{EPPCPR}_{yrc}, \text{UPPCAPD}_c, \text{UPGNPD}_y, \text{EWGINT}, \\ &\quad \text{EPNFDT}_{yr}, \text{EWGROR}, \text{TXBOOK}, \text{FNBOOK}) \\ \text{PRATIO} &= \text{TXBOOK} / \text{FNBOOK} \\ \text{CAPNNSTL} &= \text{FNBOOK} \\ \text{CALL EPCNBLD} &(\text{EPNFDT}_{yr}, \text{PRATIO}, \text{EPNRPRM}_{yr}, \text{EPNIPRM}_{yr}, \text{EPUCRE}_{yr}, \\ &\quad \text{EPUIRT}_{yr}, \text{EPTXRT}_{yr}, \text{EPPTLF}_{yrc}, \text{EPPNCLF}_{yrc}, \text{EPPNLLF}_{yrc}, \text{CAPNUG}) \\ \text{TRANS} &= \text{EPCOVR}_{yrc} * \text{UPGNPD}_y * \text{EPCCRF}_{yrc} \\ \text{OBJVAL} &= ((\text{CAPNNSTL} * \text{CAPNUG} + \text{TRANS}) / (\text{CRF}(\text{EPDSCRT}, \text{IFPH2}) * \\ &\quad \text{PWF}(\text{EPDSCRT}, \text{OLYR})) \\ \text{CBLD}_{yrc} &= \text{OBJVAL} + \text{PV\$FOM} \end{aligned}$$

where: EPUCRE_{yr} = Utility return on common equity in region r year y.
 EPNRPRM_{yr} = Non-utility return-on-equity premium in region r year y.
 EPNIPRM_{yr} = Non-utility interest premium in region r year y.
 EPNFDT_{yr} = Non-utility debt fraction for region r year y.
 EPPNLLF_{yrc} = Loan life for non-utility dispatchable capacity type c in region r year y. (Years)

$EPPNCLF_{yrc}$ = Contract life for non-utility dispatchable capacity type c in region r year y. (Years)
 $CAPNUG$ = Fixed charged factor to transform the installed book value into a fixed nominal annuity for non-utility builds returned from EPNCBLD.

Purchased Capacity Row Coefficient (Million \$/Gigawatt):

$VALUE_{yjc} = OBJVAL$ (from above calculation)

for j = OLYR,ECP\$XPH

Revise matrix coefficients of the build dispatchable capacity for another region vectors (BDI_{yrcgo}) for each dispatchable capacity type c, region r, import region g, and year y.

Objective Function Coefficient (Million \$/Gigawatt):

$TRANS = EPTCST_{yrg} * UPGNPD_y * EPTCRF_{yrg}$
 $OBJVAL = ((CAPNNSTL * CAPNUG + TRANS) / (CRF(EPDSCRT,IFPH2) * PWF(EPDSCRT,OLYR))$
 $CBDI_{yrcgo} = OBJVAL + PV\FOM

Purchased Capacity Row (for import region) Coefficient (Million \$/Gigawatt):

$VALUE_{yjc} = OBJVAL$ (from above calculation)

for j = OLYR,ECP\$XPH

Reserve Margin Row (for import region) Coefficient (Fraction):

$VALUE_{jgc} = EPTLOSS_{yrg}$

for j = OLYR,ECP\$XPH

Capacity Balance Row (for import region) Coefficient (Fraction):

$VALUE_{jgc} = - EPTLOSS_{yrg}$

for j = OLYR,ECP\$XPH

SUBROUTINE: EPINCST

Description: EPINCST converts an overnight cost, a construction profile and the cost of capital into an installed cost on both a book and a tax basis.

Called By: EP\$RETRO,EP\$BDSP,EP\$INT,EP\$BRNW

Equations:

$$TXBOOK = \sum_{I=1}^{CLT} (YCWP + (TXBOOK + (0.5 \cdot YCWP)) \cdot INTR \cdot DEBT_F)$$

$$BVBOOK = \sum_{I=1}^{CLT} (YCWP + (BVBOOK + (0.5 \cdot YCWP)) \cdot ROR)$$

where: $YCWP = OVR CST \cdot PROFILE(I) \cdot CAPE SC(J) \cdot GNPF(J)$
 $J = CYR + FYR + I - 2$

CLT = Construction Lead Time

INTR = Interest Costs

DEBT_F = Construction Debt Financing

ROR = Rate of Return

TXBOOK = Tax Basis Installed Costs

BVBOOK = Book Value Installed Costs

YCWP = Annual Construction Work in Progress

CYR = Current Model Year

FYR = First Year in the Construction Cycle

OVR CST = Overnight Costs

PROFILE(XPH) = Annual expenditure Percentage

CAPE SC(NYR+XPH) = Capital Escalation/Real

GNPF(NYR+FPH) = General Inflation

NYR = Number of Model Years

XPH = # of Years in Full Planning Horizon (6 Years)

FPH = # of Years in Full Planning Horizon (30 Years)

SUBROUTINE: EPNBLD

Description: EPNBLD determines the fixed charge factor to transform the installed book value into a fixed nominal annuity for utility builds.

Called By: EP\$RETRO,EP\$BDSP,EP\$INT,EP\$BRNW

Equations: Calculate Present Value of Rate Base

Calculate Present Value of Accumulated Tax Depreciation

$$X = \text{TAXDEPR}(J,I)$$

$$D(J) = U$$

$$U = U + X$$

where $j = 1,21$

$l = 1-5$, based on tax life of unit

$$Z = \text{PVV}(D,CL,CL,DR)$$

Calculate Present Value of the Rate Base

$$Y = \text{PVBV}(EL,CL,DR)$$

$$X = 1/\text{CRF}(DR,CL)$$

$$\text{PVRB} = X - Y - (Z - Y) * T * \text{RATIO}$$

Calculate Remainder of the Capital Charge

$$X = \text{PVRB} * \text{ROR}$$

$$Y = (1/\text{REAL}(EL))/\text{CRF}(DR,CL)$$

$$Z = \text{PVRB} * \text{PE} * \text{ROR} * T / (1 - T)$$

$$\text{UTIL} = X + Y + Z$$

$$\text{NBLDP1} = \text{UTIL} * \text{CRF}(DR,CL)$$

where:

TAXDEPR = Tax depreciation rates.

CRF = Function that calculates the present value of the book value outstanding.

PVV = Function that calculates the present value of a vector of numbers.

PVBV = Function that calculates the present value of the book value outstanding.

ROR = Rate of Return

DR = Utility Discount Rate (nominal, tax-adjusted rate of return)

RATIO = Ratio of tax basis to book basis.

PE = Taxable Portion of ROR

EL = Economic Life of Unit

TL = Tax Life of Unit

T = Net Tax Rate

CL = Contract Life of Unit

SUBROUTINE: EPCNBLD

Description: EPCNBLD determines the fixed charge factor to transform the installed book value into a fixed nominal annuity for non-utility builds.

Called By: EP\$BDSP,EP\$INT,EP\$BRNW

Equations: EWGROE = ROEPRM + UTROE
EWGINT = INTPRM + UTINT
EFRAC2 = 1 - DF2
X = REAL(DL2)

DPP = 1/X * DF2
PVDPP = DPP/CRF(EWGROE,DL2)
PVDEBT = (X/EWGROE * (1-((1-(1+EWGROE)**(-X))/(X*EWGROE))))/X*DF2
PVINT = PVDEBT

D(J) = TAXDEPR(J,I)

where J = 1,21
I = 1-5, based on tax life of unit

PVTB = PVV(TAXDEPR(1,I),21,TL,EWGROE) * RATIO
CAP = (EFRAC2/(1-TR)+PVINT-(TR/(1-TR)*PVTB)+PVDPP/(1-TR)
CAP = CAP * CRF(EWGROE,CL)

where:

TAXDEPR = Tax depreciation rates.
CRF = Function that calculates the present value of the book value outstanding.
PVV = Function that calculates the present value of a vector of numbers.
PVBV = Function that calculates the present value of the book value outstanding.
RATIO = Ratio of tax basis to book basis.
EL = Economic Life of Unit
TL = Tax Life of Unit
TR = Net Tax Rate
CL = Non-Utility Contract Life of Unit
UTROE = Utility ROE
UTINT = Utility Interest Rate
INTPRM = Non-Utility Interest Rate Premium
ROEPRM = Non-Utility Equity ROR Premium
DF2 = Non-Utility Debt Fraction
DL2 = Non-Utility Debt Loan Life <= Contract Life
EWGROE = Non-Utility Required ROE (Utility plus Premium)
EWGINT = Non-Utility Required Interest (Utility + Premium)
EFRAC2 = Non-Utility Equity Fraction
DPP = Debt Principal Payment
PVDPP = Present Value of Debt Principal Payment
PVDEBT = Present Value of Outstanding Debt Principal
PVINT = Present Value of Interest Payments
PVTB = Present Value of Tax Depreciation Benefits

SUBROUTINE: EPFLPRC

Description: EPFLPRC creates expected fuel prices for each ECP fuel category in each time period of the planning horizon and for each planning region. This is accomplished by combining previous model year EFD supply region prices, real price growth expectations computed at either supply, reporting or planning regions, expected inflation index, utility discount rate and three sets of mapping factors. First, a quantity weighted average price is computed at the planning region level across the supply regions for each EFD fuel type. Second, a weighted average real price growth index is computed for each year in the full planning horizon and for each planning region. Finally, the results of the first two steps is combined with mapping from EFD to ECP fuel categories and the inflation index to produce nominal ECP fuel prices for each period in the planning horizon. The discount rate is used to discount these prices to the beginning of the planning horizon.

Called By: ECPOML
Calls: PWF,PVV
Equations: Average Real Cost of Fuels by EFD Category i

$$AVGEFD_i = \sum_r UPFUEL_{ir} * EPFLRG_{ir} / \sum_r EPFLRG_{ir}$$

For r = 1 to Maximum Number of Fuel Supply Regions

where: $UPFUEL_{ir}$ = Delivered price of EFD Fuel i in fuel supply region r.
 $EPFLRG_{ir}$ = Electricity supply region to fuel supply region mapping

Average Growth Rate by EFD Category i and Planning Year y

$$EFDPRC_{iy} = \sum_r GROWTH_{iy,r} * EPCRMP_{ir} / \sum_r EPCRMP_{ir}$$

For y = 1 to ECP\$FPH and r = 1 to Maximum Number of Census Regions

where: $GROWTH_{iy,r}$ = Expected price of EFD fuel i in census region r year y.
 $EPCRMP_{ir}$ = Electricity supply region to census region mapping.

Nominal Present Value ECP Prices, Category j and Planning Year y - Single Year Periods

$$EPPFL_{iy} = PWF(EPDSCRT,y) * UPGNPD_y * (\sum_i AVGEFD_i * EFDPRC_{iy} * EPFMAP_{ij} / \sum_i EPFMAP_{ij})$$

For y = 1 to ECP\$XPH - 1

where: $UPGNPD_y$ = Inflation rate for converting to nominal dollars
 PWF = Present Worth Factor Function
 $EPDSCRT$ = Utility discount rate (nominal,tax-adjusted rate of return)
 $EPFMAP_{ij}$ = EFD fuel type to ECP fuel type mapping.

Nominal Present Value ECP Price for Final Multiyear Planning Period, Category j

$$ECPPRC2_{iy} = UPGNPD_y * (\sum_i AVGEFD_i * EFDPRC_{iy} * EPFMAP_{ij} / \sum_i EPFMAP_{iy})$$

$$EPPFL_{iy} = PVV (ECPPRC2_{iy} , ECP\$FPH - ECP\$XPH - 1 , EPDSCRT)$$

$$* PWF (EPDSCRT , ECP\$XPH)$$

For Y = ECP\\$XPH and y = ECP\\$XPH to ECP\\$FPH

where: PVV = function that calculates the present value of a vector of numbers.

ECP\\$FPH = Length of Full Planning Horizon (30 Years)

ECP\\$XPH = Length of Explicit Planning Horizon (6 Years)

SUBROUTINE: EP\$ODSP

Description: EP\$ODSP revised the operate vectors for dispatchable capacity types to reflect current fuel price expectations and shifts in the load shape. Subroutine EPDRATE is called to determine the appropriate derate factor for each capacity type in each load slice for every time period in the planning horizon. The product of the derate factor times the width of the load slice gives the quantity of electricity produced by one unit of capacity for the load slice. The sum of this product across all the load slices served by an operate vector provides the quantity of electricity produced per unit of capacity utilized by the operate vector. The objective function value for the operate is determined by computing the fuel cost and other variable operation and maintenance costs required to produce this amount of electricity. Similarly, the amount of sulfur dioxide added to the emission constraint is a function of the electricity produced.

Called By: ECPOML
Calls: EPDRATE

Equations: Calculate the SO₂ content of ECP fuels by mapping the SO₂ content of the Electricity Fuel Dispatch (EFD) fuels to ECP fuels.

$$\begin{aligned} \text{SO2_CNT}_f &= \sum_d \text{EPFSOX}_{yrd} \cdot \text{EPFMAP}_{yrd} \\ \text{SO2_WGHT} &= \sum_d \text{EPFMAP}_{yrd} \\ \text{SO2_CNT}_f &= \text{SO2_CNT}_f / \text{SO2_WGHT} \end{aligned}$$

where: EPFSOX_{yrd} = Sulfur dioxide emission rate for EFD fuel type d in region r year y. (Pounds / Million Btu)
 EPFMAP_{yrd} = Mapping between EFD fuel type d and ECP fuel type f in region r year y.

Revise matrix coefficients of operate dispatchable capacity vectors (OPD_{yrcfm}) for each dispatchable capacity type c, fuel type f, mode m, region r and year y.

Load Requirements Row Coefficient - Derate (Fraction):
Derates updated only as necessary during special 1-2 year runs of the ECP LP because of time constraints during NEMS production runs.

CALL EPDRATE(EPHGHT_{yrl}, EPWDTH_{yrl}, EPSPK_{yr}, EPLDGR_{yrl}, EPPMCF_{yr},
EPPPMR_{yr}, EPPFOR_{yr}, DERATE)
 $\text{ELA}_{yrcfm} = \text{DERATE}_{yrcf}$

for $l = 1, (\text{ECP\$VLS} - m + 1)$

where: EPHGHT_{yrl} = Height of vertical load segment l in region r year l. (Gigawatt)
 EPWDTH_{yrl} = Width of vertical load segment l in region r year l. (Hours)
 EPSPK_{yr} = Peak load for season s in region r year y. (Hours)
 EPLDGR_{yrl} = Load group for vertical load segment l in region r year y.
 EPPMCF_{yr} = Maximum capacity factor for dispatchable capacity type c in region r year y. (Fraction)
 EPPPMR_{yr} = Planned maintenance rate for dispatchable capacity type c in region r year y. (Fraction)

$EPPFOR_{yrc}$ = Forced outage rate for dispatchable capacity type c in region r year y. (Fraction)
 $DERATE$ = Derate factor returned from EPDRATE (Fraction)
 $ECP\$VLS$ = Number of vertical load slices (22).

Calculate the total generation over all load segments in the current mode.

$$GEN = \sum_i DERATE_{yri} \cdot EPWDTH_{yri}$$

Objective Function Coefficient (Million \$/Gigawatt):

$$\begin{aligned}
 VOMCST &= UPGNPD_y \cdot (EPPVOM_{yrc} + EPPEXT_{yrc}) \\
 VOMCST &= VOMCST \cdot PWF(EPDSCRT,y) \\
 COPD_{yrdm} &= 0.000001 \cdot GEN \cdot (VOMCST + EPPHRT_{yrc} \cdot EPPFL_{yri})
 \end{aligned}$$

where: $EPPVOM_{yrc}$ = Variable operating and maintenance costs for dispatchable capacity type c in region r year y. (\$/Thousand kilowatthours)
 $EPPEXT_{yrc}$ = Externality costs for intermittent capacity type i in region r year y. (\$/Thousand kilowatthours)
 $EPPHRT_{yrc}$ = Heat rate for dispatchable capacity type c in region r year y. (BTU/Kilowatthour)
 $EPPFL_{yri}$ = Present value of expected fuel price for fuel type f in region r year y. (\$/Million Btu)

SO2 Emission Constraint Coefficient (Million TONS/Gigawatt):

$$SO2_{yrdm} = 0.0000005 \cdot GEN \cdot EPPHRT_{yrc} \cdot SO2_CNT_i \cdot (1.0 - EPPSEF_{yrc})$$

where: $EPPSEF_{yrc}$ = Scrubber efficiency rate for dispatchable capacity c in region r year y. (Fraction)

SUBROUTINE: EPDRATE

Description: EPDRATE calculates the derates factors for dispatchable capacity types across all load slices. The derate 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. The forced outages apply equally to all load segments. Planned maintenance outages are inversely proportional to the height of the peak segment in each season. The load following outages are inversely proportional to height of each segment within a daily load cycle. This methodology tends to levelize the risk of a loss of load across all load segments.

Called By: EP\$ODSP

Equations: Derate Factor for Load Segment I

$$DERATE_I = T\$FO_I * T\$PM_I * T\$LF_I$$

Forced Outage Factor Load Segment I

$$T\$FO_I = 1.0 - FOR$$

Planned Maintenance Outage Factor for Load Segment I

$$T\$PM_I = \text{MIN} (1.0 , \text{PEAK}_I / \text{PM\$HGHT})$$

PEAK_I is peak in the season containing segment I.

PM\$HGHT is minimum height which allows all planned maintenance to be scheduled.

Load Following Outage Factor for Load Segment I

$$T\$LF_I = \text{MIN} (1.0 , \text{HGHT}_I / \text{LF\$HGHT})$$

HGHT_I is height of segment I.

LF\$HGHT is minimum daily height which allows all load following to be performed.

SUBROUTINE: EP\$INT

Description: EP\$INT revises the upper bounds on existing intermittent capacity vectors for each year of the current planning horizon. Like EP\$BDSP, EP\$INT's primary function is the revision of the objective function value for the build vectors of each intermittent capacity type. The same four build types apply and the same financial functions are used (PVV, PWF, EPINCST, EPNBLD, EPCNBLD, CRF, and CRCONST) to calculate the objective function values and coefficients in the purchased capacity constraint. For intermittents with applicable subsidies, the objective function values are adjusted to reflect these subsidies. The contributions to load are also revised in this subroutine. In addition, penetration and resource constraints are revised in this subroutine.

Called By: ECPOML
Calls: EPINCST,EPNBLD,EPCNBLD

Equations: Revise matrix coefficients of the existing intermittent capacity vectors (EXI_{yni}) for each intermittent capacity type i, region r and year y.

Column Upper Bound

$$EXI_{yni} \leq EPICAP_{yni} * .001$$

where: $EPICAP_{yni}$ = Existing Capacity for intermittent capacity i in region r year y. (Megawatt)

Reserve Margin Row Coefficient (Fraction):

$$RMI_{yni} = EPICFC_{yni1} * 0.5$$

where: $EPICFC_{yni1}$ = Maximum capacity factor for peak load (vertical load segment 1) for intermittent capacity i in region r year y. (Megawatt)

Load Requirements Row Coefficient:

$$ELI_{ynil} = EPICFC_{ynil}$$

where: $EPICFC_{ynil}$ = Maximum capacity factor for vertical load segment l for intermittent capacity i in region r year y. (Megawatt)

Calculate present value of intermittent variable cost subsidies, variable costs and fixed O&M costs at on line year (construction lead time + y).

$$SOM_j = WCSUWN_{(j+OLYR-1)} * UPGNPD_{(j+OLYR+OLYR-2)}$$

$$FOM_j = (EPIFOM_{yni} + EPCFOM_{yni}) * UPGNPD_{(j+OLYR+OLYR-2)}$$

$$VOM_j = (EPIVOM_{yni} * 8.76 * EPIACF_{yni} + EPIEXT_{yni}) * UPGNPD_{(j+OLYR+OLYR-2)}$$

for j = 1 , IFPH2 (ECP\$FPH - OLYR + 1)

$$PV\$SOM = PVV(SOM,ECP\$FPH,IFPH2,EPDSCRT) * PWF(EPDSCRT,OLYR)$$

$$PV\$FOM = PVV(FOM, ECP\$FPH, IFPH2, EPDSCRT) * PWF(EPDSCRT, OLYR)$$

$$PV\$VOM = PVV(VOM, ECP\$FPH, IFPH2, EPDSCRT) * PWF(EPDSCRT, OLYR)$$

where: WCSUWN_y = Variable cost subsidies for wind capacity in year y. (\$/Thousand Kilowatthours) Note: There are no variable cost subsidies for solar thermal capacity.

UPGNPD_y = Inflation rate for converting to nominal dollars.

EPIFOM_{yri} = Fixed operating and maintenance costs for intermittent capacity type i in region r year y. (\$/Kilowatthour)

EPCFOM_{yri} = Fixed operating and maintenance transmission costs for capacity type i in region r year y. (\$/Kilowatthour)

EPIVOM_{yri} = Variable operating and maintenance costs for intermittent capacity type i in region r year y. (\$/Thousand Kilowatthours)

EPIACF_{yri} = Average capacity factor for intermittent capacity type i in region r year y. (Fraction)

EPIEXT_{yri} = Externality costs for intermittent capacity type i in region r year y. (\$/Thousand Kilowatthours)

OLYR = On line year for capacity type c build.

IFPH2 = ECP\$FPH - OLYR + 1

ECP\$FPH = Length of Full Planning Horizon (30 Years)

EPDSCRT = Utility discount rate (nominal, tax-adjusted rate of return)

PVV = function that calculates the present value of a vector of numbers.

PWF = Present Worth Factor Function

Revise RHS value of the intermittent build limit constraints for each intermittent capacity type i, and region r.

$$INTL_{ir} = (ILIMIT_{1r} - EPICAP_{yri}) * .001$$

where: ILIMIT_{1r} = WCAWIEL_{1r} - Total available wind capacity in the first year of the planning horizon in region r. (Megawatt)

= WCASTEL_{1r} - Total available solar thermal capacity in the first year of the planning horizon in region r. (Megawatt)

Revise matrix coefficients of the utility intermittent builds (o=U)

Revise matrix coefficients of build intermittent capacity vectors (INT_{yrio}) for each intermittent capacity type i, region r, and year y.

Objective Function Coefficient (Million \$/Gigawatt):

$$OVR CST = EPIOVR_{yri} * UPIOPT_i * UPILC_i$$

$$CALL EPINCST(MNUMYR, ECP\$XPH, ECP\$FPH, EPICLT_{yri}, CURIYR, y, OVR CST, EPICPR_{yri}, UPICAPD_i, UPGNPD_y, EPUIRT_{yri}, EPUFDT_{yri}, EPUROR_{yri}, TXBOOK, FNBOOK)$$

$$URATIO = TXBOOK / FNBOOK$$

CAPUNSTL = FNBOOK
 CALL EPNBLD(EPUROR_{yr}, EPDSCRT, URATIO, EPUFPE_{yr}, EPIELF_{yn}, EPITLF_{yn},
 EPTXRT_{yr}, EPIUCLF_{yn}, CAPUTIL)
 TRANS = EPCOVR_{yn} * UPGNPD_y * EPCCRF_{yn}
 OBJVAL = ((CAPUNSTL * CAPUTIL + TRANS) / (CRF(EPDSCRT, IFPH2) *
 PWF(EPDSCRT, OLYR))
 CINT_{yn} = OBJVAL + PV\$FOM + PV\$VOM - PV\$SOM

where: EPIOVR_{yn} = Overnight capital cost for intermittent capacity type i in region
 r year y. (\$/Kilowatt)
 UPIOPT_i = Technical optimism factor for intermittent capacity type i.
 UPILC_i = Learning Curve factor for intermittent capacity type i.
 MNUMYR = Current year of NEMS run (1990 - 2010)
 ECP\$FPH = Length of Full Planning Horizon (30 Years)
 ECP\$XPH = Length of Explicit Planning Horizon (6 Years)
 EPICLT_{yn} = Construction lead time for intermittent capacity type i in region
 r year y. (Years)
 CURIYR = Current forecast year of NEMS run (1 = 1990)
 EPICPR_{yn} = Construction profile for intermittent capacity type i in region r
 year y. (Fraction)
 UPICAPD_i = Real capital cost deflator for intermittent capacity type i.
 EPUIRT_{yr} = Utility Interest Rate in region r year y.
 EPUFDT_{yr} = Utility debt fraction for region r year y. (Fraction)
 EPUROR_{yr} = Utility Rate of Return for region r year y.
 TXBOOK = Tax basis installed costs returned from EPINCST
 FNBOOK = Book value installed costs returned from EPINCST
 EPDSCRT = Utility discount rate (nominal, tax-adjusted rate of return)
 EPUFPE_{yr} = Taxable portion of utility rate of return in region r year y.
 (Fraction)
 EPIELF_{yn} = Economic life for intermittent capacity type i in region r year y.
 (Years)
 EPITLF_{yn} = Tax life for intermittent capacity type i in region r year y. (Years)
 EPIUCLF_{yn} = Contract life for utility intermittent capacity type i in region r year
 y. (Years)
 EPTXRT_{yr} = Net Tax Rate for region r year y.
 CAPUTIL = Fixed charged factor to transform the installed book value into
 a fixed nominal annuity returned from EPNBLD.
 EPCOVR_{yn} = Overnight capital costs for transmissions for capacity type i in
 region r year y. (\$/Kilowatt)
 UPGNPD_y = Inflation rate for converting to nominal dollars
 EPCCRF_{yn} = Fixed charge factor for transmissions for capacity type i in
 region r year y. (Fraction)
 CRF = Capital Recovery Factor Function
 PWF = Present Worth Factor Function

Reserve Margin Row Coefficient (Fraction):

$$RMI_{jri} = EPICFC_{yn1} * 0.5$$

for j = OLYR, ECP\$XPH

Load Requirement Row Coefficient (Fraction):

$$ELI_{jri} = EPICFC_{yri}$$

for j = OLYR,ECP\$XPH

Purchased Capacity Row Coefficient (Million \$/Gigawatt):

$$VALUE_{yri} = CAPUNSTL * CRCONST(UPTCRT,EPUFPE_{yr},EPUROR_{yr},EPUFDT_{yr},EPUIRT_{yr},EPTXRT_{yr},EPITLF_{yri},EPIELF_{yri},URATIO,PYR)$$

for j = OLYR,ECP\$XPH

where: CRCONST = Function that calculates a scalar that represents the excess earnings available to utility to support its fixed commitments to purchased power contracts per dollar invested in rate base.

UPTCRT = Target coverage ratio.

PYR = j - OLYR + 1.

Revise matrix coefficients of the build intermittent capacity for another region vectors (BII_{yrgo}) for each intermittent capacity i, region r, import region g, and year y.

Objective Function Coefficient (Million \$/Gigawatt):

$$\begin{aligned} TRANS &= EPTCST_{yrg} * UPGNPD_y * EPTCRF_{yrg} \\ OBJVAL &= ((CAPUNSTL * CAPUTIL + TRANS) / (CRF(EPDSCRT,IFPH2) * PWF(EPDSCRT,OLYR)) \\ CBII_{yrgo} &= OBJVAL + PV\$FOM + PV\$VOM - PV\$SOM \end{aligned}$$

where: EPTCST_{yrg} = Transmission costs for interregional capacity additions from region r to region g in year y. (\$/Kilowatt)

EPTCRF_{yrg} = Transmission annuity factor for interregional capacity additions from region r to region g in year y. (Fraction)

Purchased Capacity Row (for import region) Coefficient (Million \$/Gigawatt):

$$VALUE_{ygi} = CAPUNSTL * CRCONST(UPTCRT,EPUFPE_{yr},EPUROR_{yr},EPUFDT_{yr},EPUIRT_{yr},EPTXRT_{yr},EPITLF_{yri},EPIELF_{yri},URATIO,PYR)$$

for j = OLYR,ECP\$XPH

Reserve Margin Row (for import region) Coefficient (Fraction):

$$VALUE_{jgi} = EPICFC_{yri} * EPTLOSS_{yrg} * .05$$

for j = OLYR,ECP\$XPH

where: EPTLOSS_{yrg} = Transmission loss factor for interregional capacity additions from region r to region g in year y. (Fraction)

Load Requirements Row (for import region) Coefficient (Fraction):

$$ELI_{jri} = EPICFC_{yri}$$

for j = OLYR,ECP\$XPH

Revise matrix coefficients of the intermittent non-utility builds (o=N)

Revise matrix coefficients of the build intermittent capacity vectors (INT_{yrio}) for each intermittent capacity type i, region r and year y.

Objective Function Coefficient (Million \$/Gigawatt):

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EWGROE = EPUCREyr + EPNRPRMyr
EWGINT = EPUIRTyr + EPNIPRMyr
EWGROR = EWGROE * (1.0 - EPNFDTyr) + EWGINT * EPNFDTyr
OVR CST = EPIOVRyri * UPIOPTi * UPILCi
CALL EPINCST(MNUMYR,ECP$XPH,ECP$FPH,EPICLTyri,CURIYR,y,
              OVR CST,EPICPRyri,UPICAPDi,UPGNPDy,EWGINT,
              EPNFDTyr,EWGROR,TXBOOK,FNBOOK)
PRATIO = TXBOOK/FNBOOK
CAPNNSTL = FNBOOK
CALL EPCNBLD(EPNFDTyr,PRATIO,EPNRPRMyr,EPNIPRMyr,EPUCREyr,
              EPUIRTyr,EPTXRTyr,EPITLFyri,EPINCLFyri,EPINLLFyri,CAPNUG)
TRANS = EPCOVRyri * UPGNPDy * EPCCRFyri
OBJVAL = ((CAPNNSTL * CAPNUG + TRANS) / (CRF(EPDSCRT,IFPH2) *
PWF(EPDSCRT,OLYR)
CINTyrio = OBJVAL + PV$FOM + PV$VOM - PV$SOM

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where: EPUCRE_{yr} = Utility return on common equity in region r year y.
 EPNRPRM_{yr} = Non-utility return-on-equity premium in region r year y.
 EPNIPRM_{yr} = Non-utility interest premium in region r year y.
 EPNFDT_{yr} = Non-utility debt fraction for region r year y.
 EPPINLF_{yrc} = Loan life for non-utility intermittent capacity type c in region r year y. (Years)
 EPPICLF_{yrc} = Contract life for non-utility intermittent capacity type c in region r year y. (Years)
 CAPNUG = Fixed charged factor to transform the installed book value into a fixed nominal annuity for non-utility builds returned from EPCNBLD.

Reserve Margin Row Coefficient (Fraction):

$$RMI_{jri} = EPICFC_{yri1} * 0.5$$

for j = OLYR,ECP\$XPH

Load Requirements Row Coefficient (Fraction):

$$ELI_{jri} = EPICFC_{yni}$$

for j = OLYR,ECP\$XPH

Purchased Capacity Row Coefficient (Million \$/Gigawatt):

$$VALUE_{yni} = OBJVAL \text{ (from above calculation)}$$

for j = OLYR,ECP\$XPH

Revise matrix coefficients of the build intermittent capacity for another region vectors (BII_{ynigo}) for each intermittent capacity i, region r, import region g, and year y.

Objective Function Coefficient (Million \$/Gigawatt):

$$\begin{aligned} TRANS &= EPTCST_{yrg} * UPGNPD_y * EPTCRF_{yrg} \\ OBJVAL &= ((CAPNNSTL * CAPNUG + TRANS) / (CRF(EPDSCRT,IFPH2) * \\ &PWF(EPDSCRT,OLYR) \\ CBII_{ynigo} &= OBJVAL + PV\$FOM + PV\$VOM - PV\$SOM \end{aligned}$$

Purchased Capacity Row (for import region) Coefficient (Million\$/Gigawatt):

$$VALUE_{ygi} = OBJVAL \text{ (from above calculation)}$$

for j = OLYR,ECP\$XPH

Reserve Margin Row (for import region) Coefficient (Fraction):

$$VALUE_{jgi} = EPICFC_{yni} * EPTLOSS_{yrg} * .05$$

for j = OLYR,ECP\$XPH

Load Requirements Row (for import region) Coefficient (Fraction):

$$ELI_{jgi} = EPICFC_{yni}$$

for j = OLYR,ECP\$XPH

SUBROUTINE: EP\$BRNW

Description: EP\$BRNW revises the upper bounds on existing renewable capacity vectors for each year of the current planning horizon. Like EP\$BDSP and EP\$INT, EP\$INT's primary function is the revision of the objective function value for the build vectors of each non-intermittent renewable capacity type. The same four build types apply and the same financial functions are used (PVV, PWF, EPINCST, EPNBLD, EPCNBLD, CRF, and CRCONST) to calculate the objective function values and coefficients in the purchased capacity constraint. In addition, penetration and resource constraints are revised in this subroutine.

Called By: ECPOML
Calls: EPINCST, EPNBLD, EPCNBLD

Equations: Revise upper bound on existing renewable capacity vectors for each renewable capacity n, region r and year y. (Gigawatt)

$$EXR_{ym} \leq EPRCAP_{ym} * .001$$

where: $EPRCAP_{ym}$ = Existing Capacity for renewable capacity n in region r year y.
(Megawatt)

Calculate present value of fixed O&M costs at on line year (construction lead time + y).

$$FOM_j = (EPRFOM_{ym} + EPCFOM_{ym}) * UPGNPD_{(j+curiyr+olr-2)}$$

for $j = 1$, IFPH2 (ECP\$FPH - OLYR + 1)

$$PV\$FOM = PVV(FOM, ECP\$FPH, IFPH2, EPDSCRT) * PWF(EPDSCRT, OLYR)$$

where: UPGNPD_y = Inflation rate for converting to nominal dollars.
EPRFOM_{ym} = Fixed operating and maintenance costs for renewable capacity type n in region r year y. (\$/Kilowatt)
EPCFOM_{ym} = Fixed operating and maintenance transmission costs for capacity type n in region r year y. (\$/Kilowatt)
OLYR = On line year for capacity type n build.
CURIYR = Current year of NEMS run. (1 = 1990)
IFPH2 = ECP\$FPH - OLYR + 1
ECP\$FPH = Length of Full Planning Horizon (30 Years)
EPDSCRT = Utility discount rate (nominal, tax-adjusted rate of return)
PVV = function that calculates the present value of a vector of numbers.
PWF = Present Worth Factor Function

Revise RHS value for renewable build limit constraints for each renewable capacity type n and region r. (Gigawatt)

$$RNWL_{nr} = (RLIMIT_{1r} - EPRCAP_{1m}) * .001$$

where: $RLIMIT_{1r}$ = $WCAGFEL_{1r}$ - Total available geothermal capacity in the first year of the planning horizon in region r. (Megawatt)
= $WCABMEL_{1r}$ - Total available biomass capacity in the first year of the planning horizon in region r. (Megawatt)
= $WCAMSEL_{1r}$ - Total available MSW capacity in the first year of the planning horizon in region r. (Megawatt)

Revise matrix coefficients of the renewable utility builds (o=U)

Revise matrix coefficients of the build renewable capacity vectors (RNW_{ymo}) for each renewable capacity type n, region r, and year y.

Objective Function Coefficient (Million \$/Gigawatt):

```

OVR CST = EPROVRym * UPROPTn * UPRLCn
CALL EPINCST(MNUMYR,ECP$XPH,ECP$FPH,EPRCLTym,CURIYR,y,
             OVR CST,EPRCPRym,UPRCAPDn,UPGNPDy,EPUIRTyr,
             EPUFDTyr,EPURORyr,TXBOOK,FNBOOK)
URATIO = TXBOOK/FNBOOK
CAPUNSTL = FNBOOK
CALL EPNBLD(EPURORym,EPDSCRT,URATIO,EPUFPEyr,EPRELFym,
            EPRTLFym,EPTXRTyr,EPRUCLFym,CAPUTIL)
TRANS = EPCOVRym * UPGNPDy * EPCCRFym
OBJVAL = ((CAPUNSTL * CAPUTIL + TRANS) /
           (CRF(EPDSCRT,IFPH2) * PWF(EPDSCRT,OLYR))
CRNWymo = OBJVAL + PV$FOM

```

where: $EPROVR_{ym}$ = Overnight capital cost for renewable capacity type n in region r year y. (\$/Kilowatt)
 $UPROPT_n$ = Technical optimism factor for renewable capacity type n.
 $UPRLC_n$ = Learning Curve factor for renewable capacity type n.
 $MNUMYR$ = Current year of NEMS run (1990 - 2010)
 ECPFPH$ = Length of Full Planning Horizon (30 Years)
 ECPXPH$ = Length of Explicit Planning Horizon (6 Years)
 $EPRCLT_{ym}$ = Construction lead time for renewable capacity type n in region r year y. (Years)
 $CURIYR$ = Current forecast year of NEMS run (1 = 1990)
 $EPRCPR_{ym}$ = Construction profile for renewable capacity type n in region r year y. (Fraction)
 $UPRCAPD_n$ = Real capital cost deflator for renewable capacity type n.
 $EPUIRT_{yr}$ = Utility Interest Rate in region r year y.
 $EPUFDT_{yr}$ = Utility debt fraction for region r year y. (Fraction)
 $EPUROR_{yr}$ = Utility Rate of Return for region r year y.
 $TXBOOK$ = Tax basis installed costs returned from EPINCST
 $FNBOOK$ = Book value installed costs returned from EPINCST
 $EPDSCRT$ = Utility discount rate (nominal,tax-adjusted rate of return)
 $EPUFPE_{yr}$ = Taxable portion of utility rate of return in region r year y. (Fraction)

$EPRELF_{ym}$	= Economic life for renewable capacity type n in region r year y. (Years)
$EPRTLF_{ym}$	= Tax life for renewable capacity type n in region r year y. (Years)
$EPRUCLF_{ym}$	= Contract life for utility renewable capacity type n in region r year y. (Years)
$EPTXRT_y$	= Net Tax Rate for region r year y.
$CAPUTIL$	= Fixed charged factor to transform the installed book value into a fixed nominal annuity returned from EPNBLD.
$EPCOVR_{ym}$	= Overnight capital costs for transmissions for capacity type n in region r year y. (\$/Kilowatt)
$UPGNPD_y$	= Inflation rate for converting to nominal dollars
$EPCCRF_{ym}$	= Fixed charge factor for transmissions for capacity type i in region r year y. (Fraction)
CRF	= Capital Recovery Factor Function
PWF	= Present Worth Factor Function

Purchased Capacity Row Coefficient (Million \$/Gigawatt):

$$VALUE_{yrjn} = CAPUNSTL * CRCONST(UPTCRT, EPUPFE_{yr}, EPUROR_{yr}, EPUFDT_{yr}, EPUIRT_{yr}, EPTXRT_{yr}, EPRTLF_{ym}, EPRELF_{ym}, URATIO, PYR)$$

for j = OLYR, ECP\$XPH

where: CRCONST = Function that calculates a scalar that represents the excess earnings available to utility to support its fixed commitments to purchased power contracts per dollar invested in rate base.

UPTCRT = Target coverage ratio.
PYR = j - OLYR + 1.

Reserve Margin Row Coefficient (Fraction):

$$RMR_{jm} = EPRCCR_{ym}$$

for j = OLYR, ECP\$XPH

where: EPRCCR_{ym} = Capacity credit for renewable capacity type n in region r year y. (Fraction)

Revise matrix coefficients of the build renewable capacity for another region vectors (BRI_{ymgo}) for each renewable capacity n, region r, import region g, and year y.

Objective Function Coefficient (Million \$/Gigawatt):

$$\begin{aligned} TRANS &= EPTCST_{yrg} * UPGNPD_y * EPTCRF_{yrg} \\ OBJVAL &= ((CAPUNSTL * CAPUTIL + TRANS) / (CRF(EPDSCRT, IFPH2) * PWF(EPDSCRT, OLYR)) \\ CBRI_{ymgo} &= OBJVAL + PV\$FOM \end{aligned}$$

where: EPTCST_{yrg} = Transmission costs for interregional capacity additions from region r to region g in year y. (\$/Kilowatt)

$EPTCRF_{yrg}$ = Transmission annuity factor for interregional capacity additions from region r to region g in year y. (Fraction)

Purchased Capacity Row (for import region) Coefficient:

$$VALUE_{ygin} = CAPUNSTL * CRCONST(UPTCRT, EPUFPE_{yr}, EPUROR_{yr}, EPUFDT_{yr}, EPUIRT_{yr}, EPTXRT_{yr}, EPRTL_{yrm}, EPREL_{ym}, URATIO, PYR)$$

for j = OLYR, ECP\$XPH

Reserve Margin Row (for import region) Coefficient:

$$VALUE_{jgn} = EPTLOSS_{yrg} * EPRCCR_{ym}$$

for j = OLYR, ECP\$XPH

where: $EPTLOSS_{yrg}$ = Transmission loss factor for interregional capacity additions from region r to region g in year y. (Fraction)

Capacity Balance Row (for import region) Coefficient:

$$VALUE_{jgn} = -EPTLOSS_{yrg}$$

for j = OLYR, ECP\$XPH

Revise matrix coefficients of the renewable non-utility builds (o=N)

Revise matrix coefficients of the build renewable capacity vectors (RNW_{ymo}) for each renewable capacity type n, region r, and year y.

Objective Function Coefficient (Million \$/Gigawatt):

```
EWGROE = EPUCREyr + EPNRPRMyr
EWGINT = EPUIRTyr + EPNIPRMyr
EWGROR = EWGROE * (1.0 - EPNFDTyr) + EWGINT * EPNFDTyr
OVR CST = EPROVRym * UPROPTn * UPRCLn
CALL EPINCST(MNUMYR, ECP$XPH, ECP$FPH, EPRCLTym, CURIYRy,
              OVR CST, EPRCPRym, UPRCAPDn, UPGNPDy, EWGINT,
              EPNFDTyr, EWGROR, TXBOOK, FNBOOK)
PRATIO = TXBOOK/FNBOOK
CAPNNSTL = FNBOOK
CALL EPCNBLD(EPNFDTyr, PRATIO, EPNRPRMyr, EPNIPRMyr, EPUCREyr,
              EPUIRTyr, EPTXRTyr, EPRTLyrm, EPRNCLFym,
              EPRNLLFym, CAPNUG)
TRANS = EPCOVRym * UPGNPDy * EPCCRym
OBJVAL = ((CAPNNSTL * CAPNUG + TRANS) / (CRF(EPDSCRT, IFPH2) *
PWF(EPDSCRT, OLYR)
CRNWymo = OBJVAL + PV$FOM
```

where: $EPUCRE_{yr}$ = Utility return on common equity in region r year y.
 $EPNRPRM_{yr}$ = Non-utility return-on-equity premium in region r year y.
 $EPNIPRM_{yr}$ = Non-utility interest premium in region r year y.
 $EPNFDT_{yr}$ = Non-utility debt fraction for region r year y.
 $EPPRNLF_{yrn}$ = Loan life for non-utility renewable capacity type n in region r year y. (Years)
 $EPPRCLF_{yrn}$ = Contract life for non-utility renewable capacity type n in region r year y. (Years)
CAPNUG = Fixed charged factor to transform the installed book value into a fixed nominal annuity for non-utility builds returned from EPNCBLD.

Purchased Capacity Row Coefficient (Million \$/Gigawatt):

$$VALUE_{yrjn} = OBJVAL \text{ (from above calculation)}$$

for j = OLYR,ECP\$XPH

Reserve Margin Row Coefficient (Fraction):

$$RMR_{jm} = EPRCCR_{ym}$$

for j = OLYR,ECP\$XPH

Revise matrix coefficients of the build renewable capacity for another region vectors (BRI_{ymgo}) for each renewable capacity n, region r, import region g, and year y.

Objective Function Coefficient (Million \$/Gigawatt):

$$\begin{aligned} TRANS &= EPTCST_{yr} * UPGNPD_y * EPTCRF_{yr} \\ OBJVAL &= ((CAPNNSTL * CAPNUG + TRANS) / (CRF(EPDSCRT,IFPH2) * \\ &PWF(EPDSCRT,OLYR) \\ CBRI_{ymgo} &= OBJVAL + PV\$FOM \end{aligned}$$

Purchased Capacity Row (for import region) Coefficient (Million \$/Gigawatt):

$$VALUE_{ygjn} = OBJVAL \text{ (from above calculation)}$$

for j = OLYR,ECP\$XPH

Reserve Margin Row (for import region) Coefficient (Fraction):

$$VALUE_{jgn} = EPTLOSS_{yr} * EPRCCR_{ym}$$

for j = OLYR,ECP\$XPH

Capacity Balance Row (for import region) Coefficient (Fraction):

$$\text{VALUE}_{\text{ign}} = -\text{EPTLOSS}_{\text{yrj}}$$

for j = OLYR,ECP\$XPH

SUBROUTINE: EP\$ORNW

Description: EP\$ORNW revises the operate vectors for renewable technologies. The contribution to load depends on both capacity and available energy to operate the capacity. The objective function value depends on the total electricity generated by the operate vector per unit of capacity and the variable operations and maintenance costs. There are three dispatch options. 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. Third, the capacity constraint can be converted to an energy constraint and capacity utilization can be determined independently for each load segment. For the third option only, each operate vector is bounded at the existing capacity and thus precluding the addition of new capacity.

Called By: ECPOML

Equations: Revise matrix coefficients of the renewable operate vectors (OPR_{ym}) for each renewable capacity type n, region r and year y.

Load Requirements Row Coefficient (Fraction):

$$ELR_{ym} = EPRCFC_{ym}$$

where: $EPRCFC_{ym}$ = Maximum capacity factor for renewable capacity type n in region r year y. (Fraction)

Objective Function Coefficient (Million \$ / Gigawatt):

$$\begin{aligned} VOMCOST &= UPGNPD_y * (EPRVOM_{ym} + EPREXT_{ym}) \\ VOMCOST &= VOMCST * PWF(EPDSCRT,y) \\ COPR_{ym} &= EPRCFC_{ym} * 8.760 * VOMCST \end{aligned}$$

where: $UPGNPD_y$ = Inflation rate for converting to nominal dollars.
 $EPRVOM_{ym}$ = Variable operating and maintenance costs for renewable capacity type n in region r year y. (\$/Thousand Kilowatthours)
 $EPREXT_{ym}$ = Externality costs for renewable capacity type n in region r year y. (\$/Thousand Kilowatthours)

Revise matrix coefficients of the Hydroelectric operate vectors (OPH_{yr}) for each vertical load segment l, region r and year y.

Column Upper Bound:

$$OPH_{yr} \leq EPRCAP_{ym} * .001$$

where: $EPRCAP_{ym}$ = Existing Capacity for renewable capacity n (hydroelectric) in region r year y. (Megawatt)

Load Requirements Row Coefficient (Fraction):

$$ELR_{ym} = 1 - EPRFOR_{ym}$$

where: $EPRFOR_{ym}$ = Forced Outage Rate for renewable capacity n (hydroelectric) in region r year y. (Megawatt)

Objective Function Coefficient (Million \$/Gigawatt):

$$VOMCOST = UPGNPD_y * (EPRVOM_{ym} + EPREXT_{ym})$$

$$VOMCOST = VOMCOST * PWF(EPDSCRT,y)$$

$$COPH_{yn} = (1 - EPRFOR_{ym}) * EPWDTH_{yn} * VOMCOST * .001$$

where: $EPWDTH_{yn}$ = Width of the vertical load segment l in region r year y. (Hours)

Hydro Capacity Balance Row Coefficient:

$$ELR_{ym} = ((1 - EPRFOR_{ym}) * EPWDTH_{yn}) / (EPRCFC_{ym} * 8760.0)$$

SUBROUTINE: EP\$DSM

Description: EP\$DSM revises the DSM investment vectors. Each DSM program can be activated up to 100% in any time period over the planning horizon but is constrained to 100% penetration over the entire planning horizon. The reduction in load and the cost of each DSM option diminishes over time and thus depends on the initial year of implementation.

Called By: ECPOML

Equations: Revise matrix coefficients of the implement DSM vectors (DSM_{yrd}) for each DSM program d, region r and year y.

Objective Function Coefficient (Million \$/Gigawatt):

$$CDSM_{yrd} = EPDINV_{yrd}$$

where: $EPDINV_{yrd}$ = Cumulative net present value of investments in DSM program d in region r year y. (\$/Gigawatt)

Reserve Margin Coefficient:

$$RMD_{yzrd} = EPDCCR_{yrd}$$

for $z = y$, ECP\$XPH

where: $EPDCCR_{yrd}$ = Contribution to reserve margin for DSM program d in region r year y. (Fraction)

Load Requirements Row Coefficient - Derate (Fraction):

Derates updated only as necessary during special 1-2 year runs of the ECP LP because of time constraints during NEMS production runs.

$$ELD_{yzrdl} = EPDLSI_{yrdl}$$

for $z = y$, ECP\$XPH

where: $EPDLSI_{yrdl}$ = Impact of DSM program d on vertical load segment l in region r year y. (Fraction)

SUBROUTINE: EPO\$BILD

Description: EPO\$BILD retrieves the activity level for all build or build/operate vectors which require investment in the current model year in order to achieve the specified on line date. The STRPLT subroutine stores these capacity addition decisions in the plant direct access file for future use by the EFD and ECP modules. The UEXPBLD subroutine is called to transfers new generation and transmission capacity investment to the EFP module.

Called By: ECPOML
Calls: EPINCST,EPCNBLD,STRPLT,UEXPBLD

Equations: NONE

SUBROUTINE: EPO\$RETRO

Description: EPO\$RETRO retrieves the activity level for all flue gas desulfurization retrofit vectors which require investment in the current model year in order to achieve the specified on line date. The GETPLT subroutine is called to retrieve the plant records for the units to be retrofitted. This existing capacity is modified to reflect a retire date which corresponds to a start date for a new retrofitted record. The STRPLT subroutine stores the revised existing capacity data and the new retrofitted capacity data in the plant direct access file for future use by the EFD and ECP modules. The UEXPBLD subroutine is called to transfer the retrofit investment to the EFP module.

Called By: ECPOML
Calls: GETPLT,STRPLT,UEXPBLD

Equations: NONE

SUBROUTINE: EPO\$AVOID

Description: EPO\$AVOID retrieves and stores the dual values from each load slice and the reserve margin constraint. This values are passed to the DSM module in order to prescreen candidate DSM programs so that only the most competitive programs can be selected to compete against the supply options.

Called By: ECPOML

Equations: NONE

SUBROUTINE: EPO\$BANK

Description: EPO\$BANK retrieves and stores the allowances banked in the current year. These values are used to revise the allowed emissions for the current model year dispatch decisions in the EFD submodule and for the next planning cycle in the ECP submodule.

Called By: ECPOML
Calls: GETSO2,STRSO2

Equations: NONE

SUBROUTINE: EPO\$ETT

Description: EPO\$ETT captures the decision to purchase power from new Canadian hydroelectric projects. This information is used by the ETT submodule to increase the firm Canadian imports.

Called By: ECPOML

Calls: GETEIJ

Equations: NONE

SUBROUTINE: GETBLD

Description: GETBLD is a data processing routine of the EMM. It is used by the ECP to obtain cost and performance data for new capacity types.

Called By: ECPOML

Calls: NONE

Equations: NONE

SUBROUTINE: GETEIJ

Description: GETEIJ is a data processing routine of the EMM. It is used by the ECP to obtain cost data and limits on firm power imports and interregional transfers.

Called By: ECPOML, EP\$ETT, EP\$BLD, EP\$BRNW, EPO\$ETT

Calls: NONE

Equations: NONE

SUBROUTINE: GETPLT

Description: GETPLT is a data processing routine of the EMM. It is used by the ECP to obtain input data for existing capacity.

Called By: EPO\$RETRO

Calls: NONE

Equations: NONE

SUBROUTINE: GETSO2

Description: GETSO2 is a data processing routine of the EMM. It is used by the ECP to obtain data on SO₂ allowances in order to determine emissions limits.

Called By: EP\$ALLOW, EPO\$BANK

Calls: NONE

Equations: NONE

SUBROUTINE: GETSO2

Description: GETEIJ is a data processing routine of the EMM. It is used by the ECP to obtain data on SO₂ allowances in order to determine emissions limits.

Called By: EP\$ALLOW, EPO\$BANK

Calls: NONE

Equations: NONE

SUBROUTINE: STRBOUT

Description: STRBOUT is a data processing routine of the EMM. It is used by the ECP to store output data from the ECP for each electricity supply region.

Called By: ECPOML

Calls: NONE

Equations: NONE

SUBROUTINE: STREIJ

Description: STREIJ is a data processing routine of the EMM. It is used by the ECP to store decisions on firm power purchases from the ECP.

Called By: EPO\$ETT

Calls: NONE

Equations: NONE

SUBROUTINE: STRPCNTL

Description: STRPCNTL is a data processing routine of the EMM. It is used by the ECP to store a pointer list for the plant database.

Called By: ECPOML

Calls: NONE

Equations: NONE

SUBROUTINE: STRPLT

Description: STRPLT is a data processing routine of the EMM. It is used by the ECP to store capacity expansion and scrubber retrofit decisions from the ECP on the plant database.

Called By: EPO\$BILD, EPO\$RETRO

Calls: NONE

Equations: NONE

SUBROUTINE: STRSO2

Description: STRSO2 is a data processing routine of the EMM. It is used by the ECP to store banking decisions for emissions allowances from the ECP.

Called By: EPO\$BANK

Calls: NONE

Equations: NONE

SUBROUTINE: UEXPBLD

Description: UEXPBLD is a subroutine of the EFP. It is called by the ECP in order to provide investment cost data to the EFP.

Called By: EPO\$BILD, EPO\$RETRO

Calls: NONE

Equations: NONE

FUNCTION: CRCONST

Description: CRCONST calculates a scalar that represents the excess earnings available to utility to support its fixed commitments to purchased power contracts per dollar invested in rate base.

Called By: EP\$RETRO,EP\$BDSP,EP\$INT,EP\$BRNW

Calls: Functions: SUMVEC,COEFCR

Equations: $B = (EPUROR * EPUFPE) / (1 - EPUTXRT)$ Equity Component
 $D = EPUFDT * EPUIRT$ Debt Component

For first year of planning horizon:

$$OUTRB = 1.0$$

For second through last year of planning horizon:

$$CUMDEPR = (PYR - 1) / EL$$

$$OUTRB = 1 - CUMDEPR - (SUMVEC(TAXDEPR(1,TL),21,PYR-1) - CUMDEPR) * URATIO * EPUTXRT$$

$$CRCONST = -1.0 * COEFCR(B,D,UPTCRT) * OUTRB$$

where: UPTCRT = Target coverage ratio.
 EPUFPE = Taxable portion of utility rate of return in region r year y. (Fraction)
 EPUIRT = Utility Interest Rate in region r year y.
 EPUFDT = Utility debt fraction for region r year y. (Fraction)
 EPUROR = Utility Rate of Return for region r year y.
 EPUTXRT = Net income tax rate.
 TAXDEPR = Tax Depreciation Rates.
 URATIO = Ratio of tax basis to book basis.
 EL = Economic Life of Unit
 TL = Tax Life of Unit
 PYR = Year in planning horizon.
 CUMDEPR = Accumulated financial depreciation.

FUNCTION: COEFCR

Description: COEFCR calculates the excess dollars available to 'cover' purchased power payments as though they were debt payments.

Called By: EP\$PCL,Function CRCONST

Equations:
$$\text{COEFCR} = (B + D * (1 - RT) / (RT - 1)$$
$$\text{COEFCR} = \text{MAX}(\text{COEFCR}, 0.0)$$

where: RT = Target coverage ratio.

B = Equity component calculated in EP\$PCL or CRCONST.

D = Debt component calculated in EP\$PCL or CRCONST.

FUNCTION: SUMVEC

Description: SUMVEC calculates the sum of tax depreciation.

Called By: Function CRCONST

Equations:

$$\text{SUMVEC} = \sum_{I=1}^{\text{YRS}} D(I)$$

where: D = Tax Depreciation Rates.
N = 21 years.
YRS = Planning horizon year (y) - 1

FUNCTION: PVV

Description: PVV calculates the present value of a vector of numbers.

Called By: EP\$BDSP,EPFLPRC,EPNBLD,EP\$INT,EP\$BRNW

Equations:

$$PVV = \sum_{I=1}^M D(I) / ((1+XIR) ** I)$$

where: D = Vector of numbers to be present valued.
XIR = Discount rate.
M = Number of periods to discount.

FUNCTION: PWF

Description: PWF calculates a factor that equates in present value terms a value I years in the future at X discount rate.

Called By: EP\$ETT,EP\$RETRO,EP\$BDSP,EP\$FLPRC,EP\$ODSP,EP\$INT,EP\$BRNW,EP\$ORNW

Equations: $PWF = (1 + XIR)^{-I}$

where: I = Number of years into the future.
 XIR = Discount rate.

FUNCTION: CRF

Description: CRF calculates the annuity factor associated with a input interest rate and term (Years).

Called By: EP\$ETT,EP\$RETRO,EP\$BDSP,EPCNBLD,EPNBLD,EP\$INT,EP\$BRNW,EP\$ORNW

Equations: $CRF = XIR / (1 - (1 + XIR) ** (-I))$

where: I = Term (Years)
 XIR = Interest rate.

Appendix C

OPTIMIZATION AND MODELING LIBRARY (OML) SUBROUTINES AND FUNCTIONS

This appendix provides a summary of the OML routines that are called by the ECP to set up the database, revise coefficients, solve the LP model, and retrieve the solution. OML is a proprietary software package developed by KETRON Management Science.³³

DFOPEN:	Opens the datafile for the LP problem.
DFPINIT:	Initializes processing of the LP problem in the current database.
DFMINIT:	Initializes a database for matrix processing.
DFMEND:	Terminates matrix processing.
DFCLOSE:	Terminates processing of a database file.
WFDEF:	Defines the model space for the LP problem.
WFLOAD:	Loads the matrix for the LP problem into memory.
WFINSRT:	Loads the starting basis for the LP problem.
WFOPT:	Optimizes the model.
WFPUNCH:	Saves the current basis into a standard format file.
DFMRRHS:	Retrieves a right-hand side value.
DFMCRHS:	Creates or changes a right-hand side value.
DFMRBND:	Retrieves a bound value.
DFMCBND:	Creates or changes a bound value.
DFMCVAL:	Creates or changes a coefficient for a row/column intersection.
DFMMVAL:	Changes a coefficient for row/column intersection if it exists.
DFMC RTP:	Declares or changes the row type.
WFSCOL:	Retrieves solution values (e.g., activity, input cost, reduced cost) for a column vector.
WFSROW:	Retrieves solution values (e.g., activity, dual values) for a row.

³³For more information, see Ketrion Management Science, *Optimization and Modeling Library* (Draft), (Arlington, VA, November 1992).

WFRNAME: Retrieves a row name.

WFCNAME: Retrieves a column name.

Appendix D

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Appendix E

MODEL ABSTRACT

Model Name:

Electricity Capacity Planning Submodule

Model Acronym:

ECP

Description:

The Electricity Capacity Planning Submodule is a linear programming model that determines planning decisions for the electric power industry. The model determines the least-cost solution for a multi-year planning horizon based on expectations for future electricity demands and fuel prices. The ECP represents both utility and nonutility suppliers and includes supply-side and demand-side options. Fossil-fuel, nuclear, and renewable technologies are represented.

Purpose:

The ECP is designed to project changes in the mix of generating capacity that are required to meet future demands for electricity and to comply with environmental regulations. It determines the required additions to capacity or the implementation of demand-side management (DSM) programs to offset the need for new electricity supplies. The ECP also represents planning decisions for reducing emissions of sulfur dioxide, including retrofitting existing units with scrubbers and banking allowances. The model structure provides the flexibility to examine other environmental policies such as externality costs and limits on carbon emissions.

Last Model Update:

December 1993

Part of Another Model:

The ECP is a submodule of the Electricity Market Module (EMM), which is the electricity supply component of the National Energy Modeling System (NEMS).

Model Interfaces:

The ECP receives expectations for electricity demands and fuel prices from the Integrating Module of the NEMS. Cost and performance data for renewable technologies are provided by the Renewable Fuels Module (RFM). Cost and performance characteristics for DSM programs are inputs from the Load and Demand-Side Management (LDSM) Submodule. Financial information such as the capital structure and the cost of debt and equity are obtained from the Electricity Finance and Pricing (EFP) Submodule of the EMM. Capacity additions for renewables are provided to the RFM and construction expenditures for new generating units are passed to the EFP.

Official Model Representative:

- **Office:** Office of Integrated Analysis and Forecasting
- **Division:** Energy Supply and Conversion
- **Branch:** Nuclear and Electricity Analysis
- **Model Contact:** Jeffrey S. Jones
- **Telephone:** 202-586-2038

Documentation:

Energy Information Administration, *Model Documentation: Electricity Capacity Planning Submodule of the Electricity Market Module*, Washington, DC, January 1994.

Archive Media and Installation Manual:

The first model archival of the ECP, as part of the NEMS, will be done for the version used for the *Annual Energy Outlook 1994*. This will be available in early 1994.

Energy System Described by the Model:

The ECP is a linear programming model of planning decisions in the electric power industry. It represents the construction of new generating capacity, the initiation of demand-side management programs, and the implementation of compliance strategies for reducing emissions.

Coverage:

- **Geographic:** Thirteen North American Electric Reliability Council (NERC) Regions and Subregions.
- **Time Frequency:** Annually from 1990 through 2010.
- **Products:** Capacity additions for fossil-fuel, nuclear, and renewable generating technologies. Scrubber retrofits for existing coal-fired units and allowance banking.
- **Economic Sector:** Electric utilities and nonutilities.

Modeling Features:

The ECP employs a linear programming methodology to determine the least-cost solution for meeting future capacity needs and environmental requirements. The ECP is executed once for each forecast year and uses a series of FORTRAN subroutines that update the coefficients of the objective function and constraint matrix of a linear program model. The ECP is modular in its relationship with the other components of the EMM. The outputs of the ECP are written to a database that allows the flexibility to operate the rest of the EMM without executing the ECP.

Non-DOE Input Data Sources:

- North American Electric Reliability Council
 - hourly load data
- Argonne National Laboratory

- capital costs for new fossil-fuel and nuclear plants
- operations and maintenance costs for new fossil-fuel and nuclear plants
- heat rates for new fossil-fuel and nuclear plants
- outage rates for new fossil-fuel and nuclear plants
- operating life for new fossil-fuel and nuclear plants
- emission rates for new fossil-fuel and nuclear plants
- scrubber retrofit costs
- Oak Ridge National Laboratory, CONCEPT-5 Model
 - construction profiles for new fossil-fuel plants
- Environmental Protection Agency
 - emissions allowances for sulfur dioxide

DOE Input Data Sources:

- Form EIA-860, "Annual Electric Generator Report"
 - existing utility capacity
 - heat rates for existing capacity
 - planned utility capacity additions
 - planned utility capacity retirements
- Form EIA-867, "Annual Nonutility Power Producer Report"
 - existing nonutility capacity by plant type
 - planned nonutility capacity additions by plant type
 - planned nonutility capacity retirements by plant type
- Form EIA-767, "Steam-Electric Plant Operation and Design Report"
 - emission rates for existing generating units
 - pollution control equipment installed at existing generating units
- Form EIA-759, "Monthly Power Plant Report"
 - capacity factors for hydroelectric plants

Computing Environment:

- **Hardware:** IBM 3090 mainframe
- **Operating System:** MVS
- **Software:** FORTRAN 77
- **Memory Requirement:** 12000K
- **Storage Requirement:** 13000 Tracks
- **Estimated Run Time:** 4 CPU minutes for each year
- **Special Features:** The solution for the ECP is written out to a database, which can be used as an input file in order to execute the rest of the EMM without the ECP.

Independent Expert Reviews:

In October 1992, independent expert reviews of the Component Design Report for the Electricity Capacity Planning Submodule were conducted by:

Howard E. Thompson, Ph.D., Professor,
University of Wisconsin, Madison, Wisconsin

Douglas R. Bohi, Ph.D., Director, Energy and Natural Resources Division,
Resources for the Future (RFF), Washington, DC

Dallas Burtraw, Ph.D., Fellow, Quality of the Environment Division,
Resources for the Future (RFF), Washington, DC

Steven R. Elliott, Ph.D., Energy Division,
Oak Ridge National Laboratory, Oak Ridge, TN

Status of Evaluation Efforts by Sponsor:

None.

Appendix F

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 for all electric generating equipment at an existing or planned facility. The proposal is based on the owner obtaining (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.

Argonne National Laboratories "Cost and Performance Database for New Generating Technologies"

A database of current costs and performance estimates for a wide range of old and existing power generating and emission control options.

Data Sources:

Fossil Fueled Power Plants

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

Nuclear Fueled Power Plants

- o EIA, Advanced Reactor Sourcebook

Emission Control Technologies

- o Vatabuk, estimating Costs of Air Pollution Controls, Louis Publishers, 1990
- o EPRI, 1991: United Engineers and Constructors, "Technical Feasibility and costs of selective Catalytic reduction NOx Control", GS-7276
- o 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", April 1992.

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:

- o EIA "Annual Outlook for U.S. Electric Power", 1987, and EIA survey data.
- o DRI "Energy Review", Winter 1986-1987
- o A survey of Canadian taxes by ICF, Incorporated.
- o New England Power Pool, New York Power Pool, and Western Area Power Administration
- o Reliability data from NERC Mid-Atlantic Area Council, and Northeast Power Coordinating Council.
- o Various electric utilities in both Canada and the United States including; Pacific Gas and Electric, Hydro-Quebec, Manitoba Hydro, and British Columbia Hydro.
- o 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 (SO₂) emissions allowances (credits), as delineated by the Clean Air Act.

Data Sources:

- o 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 SO₂ emissions and emissions rate, 1985 total heat input, and 1985 SO₂ emission limits and associated variables.
- o 1985 National Emissions Data System (NEDS) submittals.
- o Form EIA-767 (EIA, 1982-1989) and Form FPC-67 (FPC, 1980-1981).
- o Form EIA-759 (EIA, 1980-1989).
- o The Federal Energy Regulatory Commission (FERC) Form FERC-423 (FERC, 1985-1989).
- o The EIA Integrated Data Base System (IDBS), which consists of the Form EIA-860 (EIA, 1989a) and Form EIA-861 (EIA, 1989b).

DATE
FILMED

7/15/94

END

