Documentation

Electricity Fuel Dispatch

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1. Introduction

1.1 Purpose of the Report

This report documents the National Energy Modeling System Electricity Fuel Dispatch Submodule (EFD), a submodule of the Electricity Market Module (EMM) as it was used for EIA's *Annual Energy Outlook 1997*. It replaces previous documentation dated March 1994 and subsequent yearly update revisions. The report catalogues and describes the model assumptions, computational methodology, parameter estimation techniques, model source code, and forecast results generated through the synthesis and scenario development based on these components.

This document serves four purposes. First, it is a reference document providing a detailed description of the model for reviewers and potential users of the EFD including energy experts at the Energy Information Administration (EIA), other Federal agencies, state energy agencies, private firms such as utilities and consulting firms, and non-profit groups such as consumer and environmental groups. Second, this report meets the legal requirement of the Energy Information Administration (EIA) to provide adequate documentation in support of its statistical and forecast reports (Public Law 93-275, section 57(b)(1)). Third, it facilitates continuity in model development by providing documentation which details model enhancements that were undertaken for AEO97 and since the previous documentation. Last, because the major use of the EFD is to develop forecasts, this documentation explains the calculations, major inputs and assumptions which were used to generate the AEO97.

1.2 Model Summary

The Electricity Fuel Dispatch Submodule (EFD) determines the annual allocation of available capacity (as determined in the Electricity Capacity Planning Submodule) to meet demand on a least-cost (merit-order) basis subject to current environmental regulations (Figure 1). First, available capacity is ranked from the least to most costly units according to variable costs. Second, the units are dispatched in this order (from least to most costly) until demand is satisfied. (The Electricity Capacity Planning Submodule determines the capacity needed in each year to meet demand; Demand is determined in the Demand Modules with seasonal and hourly demands determined in the Load and Demand Side Management Submodule.) Utilities have the option to purchase or sell energy to neighboring regions if it is economic.

The most significant improvement over previous AEO's is the removal of the endogenous representation of the Clean Air Act Amendments (CAAA)[1] from the EFD to its implementation in the Coal Market Module (CMM). Although still within the NEMS system, SO_2 emissions and the CAAA have more direct influence on coal supply within the CMM. The coal module now directly supplies the coal mix required to meet demand and the CAAA emission limit. NEMS as a whole gains a better modeling approach and a better analysis perspective.

In former versions, the EFD incorporated emission restrictions by an iterative process. First, a penalty cost for emitting SO_2 was added to units which emit SO_2 (in the first iteration, the penalty cost was set to zero). Next, capacity was dispatched under certain considerations and constraints until demand was satisfied and it fell below the limits imposed by the CAAA. Economy trade was then performed. Fuel consumption and emissions were then determined as a function of generation. (Emissions are still calculated here as a function of generation to ensure accuracy compliance from the CMM since the code was already in place.) Last, national SO_2 emissions were computed and examined to see if they were within the CAAA limits. The solution was achieved by iterating this process to find the smallest penalty cost that satisfied the emissions restriction.

[1]The Clean Air Act and its subsequent amendments contain federal regulations for SO_2 and NO_x emissions by electric utilities. The most recent amendments to the CAAA in 1990 set up a system of marketable allowances to emit SO_2. Each allowance entitles the holder to emit one ton of SO_2. Allowances may be traded among utilities and nonutilities, so the limit on total emissions is a national rather than a unit level limit.

During dispatching, emissions could be reduced by switching from fuels with "high" emission rates to fuels with "low" emission rates. As this mainly encompassed fuel switching in coal, the quantities demanded and the prices received from the CMM for different sulfur types of coal had a tendency to oscillate causing convergence problems. Since the penalty also reflects the price differential between high- and low-sulfur coal which is determined from the supply curves in the coal model, the ultimate solution was to move the penalty calculation to the CMM.

The formulation for the way coal was demanded needed to be revised. Formerly, the EFD provided the CMM with the requirement for a specific coal rank and sulfur type for each plant type. Now the EFD only determines the total coal demand for each plant type, without regard to rank and sulfur content. The plant types have been redefined according to vintage. The older units (pre-1965) have a more limited flexibility to switch between coal ranks. Given these constraints, the CMM satisfies the coal demand optimally for each plant type with respect to rank and sulfur. Defined regional supply patterns in the CMM also limit ranks that can be selected to prevent, for instance, lignite from being burned in an exclusively bituminous plant.

As a result of these changes, the coal module now determines the least cost sulfur penalty as well as the mix of coals necessary to meet the EMM demand; the EFD determines only the total demand (in BTUs) for each plant type. In theory, convergence problems could still arise as merit order changes would adjust the consumption of each plant type. In practice, since coal plants typically meet base-load demand, any change in the merit order due to changes in the coal price or sulfur penalty typically move various plants up or down in the merit order but leaves overall coal consumption essentially unchanged. This results in an algorithm that is very robust and significantly improved convergence.

Emissions of nitrogen oxide (NO_x) have been enhanced in the model to account for NO_x emissions by plant type and are determined based on the boiler type, control equipment (if any), and the utilization of capacity. Formerly NO_x emissions were assumed from historical rates and were found not to produce accurate estimates. This enhancement reflects new NO_x regulations and allows the model better forecasting abilities.

Another enhancement, in the fixed and variable O&M costs representation, now allows the rates to change over time. This better reflects historical trends which show rates declining. Fuel consumption is provided to the fuel supply modules while fuel and variable operations and maintenance (O&M) costs are used to determine electricity prices in the Electricity Finance and Pricing (EFP) Submodule. Electricity prices are provided to the demand models to determine electricity demand.

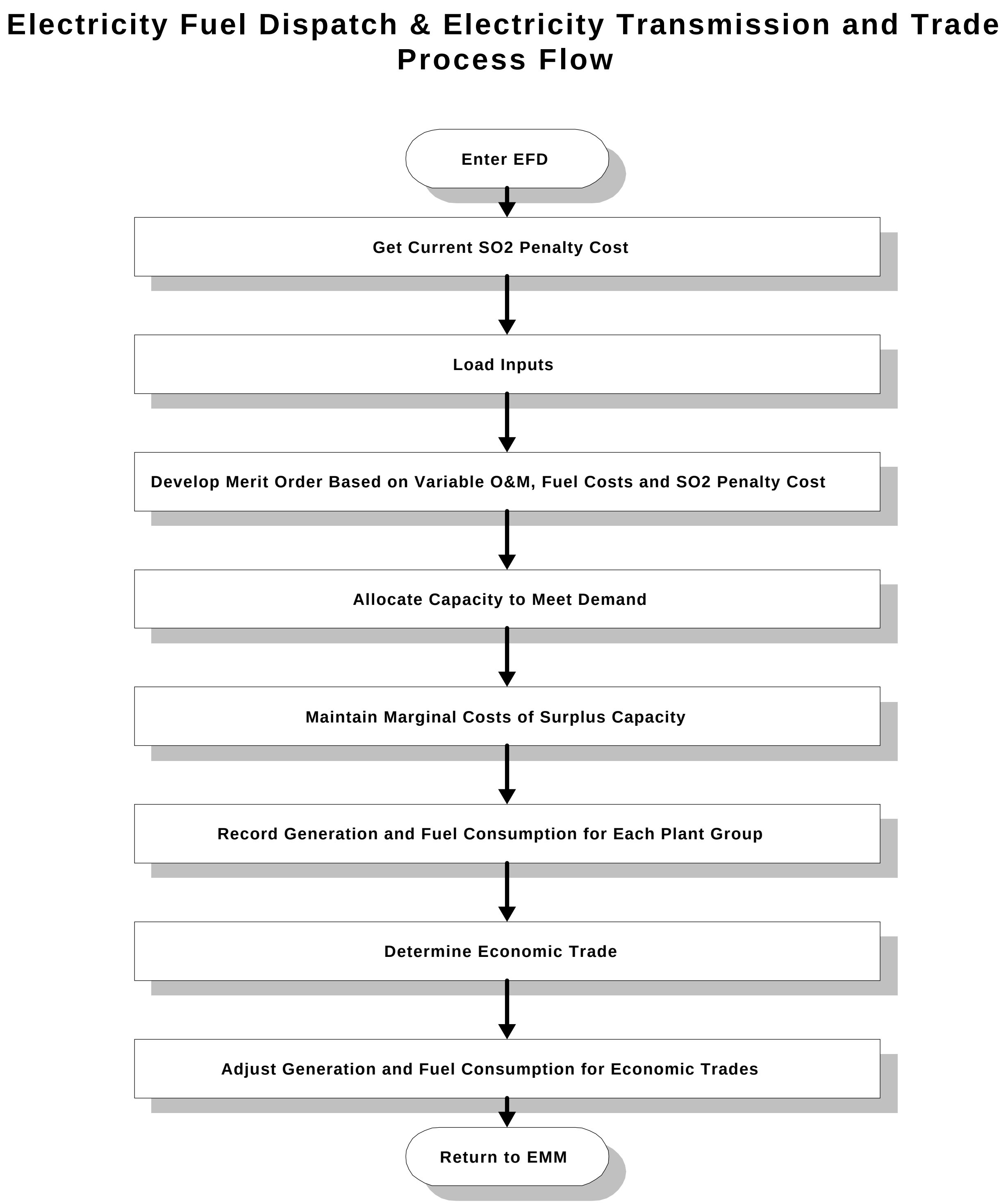
The EFD also represents nonutility (excluding cogenerators) supply and interregional economy sales endogenously. Renewable supply, demand-side management programs, international economy trade and DSM impacts are incorporated by adjusting the demand for capacity prior to the dispatching decision, i.e. the load curve is revised. Cogeneration and generation from intermittent renewable technologies are determined in the Demand Models and Renewable Models, respectively, with the demand curve adjusted to incorporate their contribution to load. The EFD dispatches nonutility supply together with utility fossil-fueled and nuclear generating capacity. Economy sales are also represented in the EFD. Utilities now have the option to purchase electricity from another region in place of generating the power themselves.

1.3 Organization of the Report

Section 2 of this report discusses the purpose of the model, detailing its objectives, primary input and output quantities, and the relationship of the EFD to other modules of the EMM and NEMS systems. Section 3 of the report describes the rationale behind the model design, providing insights into the development of the assumptions utilized in the model. Section 4 details the model structure, using graphics and text to illustrate model flows and key computations.

The Appendices to this report provide supporting documentation for the input data files, code and common blocks currently residing on a computer workstation at EIA. Appendix A lists and defines the input data used to generate parameter estimates and endogenous forecasts, along with the parameter estimates and the outputs of most relevance to the NEMS systems and the model evaluation process. A table referencing the equations and/or subroutine in which each variable appears is also provided in Appendix A. Appendix B contains a mathematical description of the computational algorithms, including model equations and variable transformations. Appendix C contains the Bibliography. Appendix D contains a summary of the Clean Air Act Amendments of 1990 which are represented in the Electricity Market Module (EMM) and have a significant impact on the results of the dispatch decision. Appendix E contains the model abstract and Appendix F outlines the quality of the data and the techniques used as estimates in the EFD.

Figure 1.


Electricity Fuel Dispatch & Electricity Transmission and Trade Process Flow
Enter EFD
Get Current SO2 Penalty Cost
Load Inputs
Develop Merit Order Based on Variable O&M, Fuel Costs and SO2 Penalty Cost
Allocate Capacity to Meet Demand
Maintain Marginal Costs of Surplus Capacity
Record Generation and Fuel Consumption for Each Plant Group
Determine Economic Trade
Adjust Generation and Fuel Consumption for Economic Trades
Return to EMM

2. Model Purpose

2.1 Model Objectives

The objective of the EFD is to represent the economic, operational and environmental considerations in dispatching. The EFD allocates available generating capacity to meet the demand for electricity on a least-cost basis, subject to restrictions on emissions such as SO_2, NO_x and carbon. The primary use of the EFD is to develop projections for the Energy Information Administration's *Annual Energy Outlook.*

The EFD addresses utility and nonutility supplies endogenously; i.e. the EFD dispatches nonutility sources[2] together with utility fossil-fuel and nuclear generating capacity. Cogeneration and intermittent renewable technologies are also represented exogenously with the load curve adjusted prior to dispatching other generating technologies.

The EFD represents the dispatch decision at the regional level. These regions, referred to as NEMS electricity supply regions, are North American Electric Reliability Council (NERC) regions and subregions. (Table 1 and Figure 2). The primary inputs from other NEMS modules are the demands for electricity and fuel prices. The resulting fuel consumption is passed to the respective fuel supply models. The fuel supply modules and end-use demand modules use other regional aggregations (Census regions and divisions, coal and gas supply regions, etc.). The interaction between the EFD and other modules of the NEMS and other regional issues, including the required transformations between different regional structures are described later in this section.

Table 1. NEMS Electricity Supply Regions

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

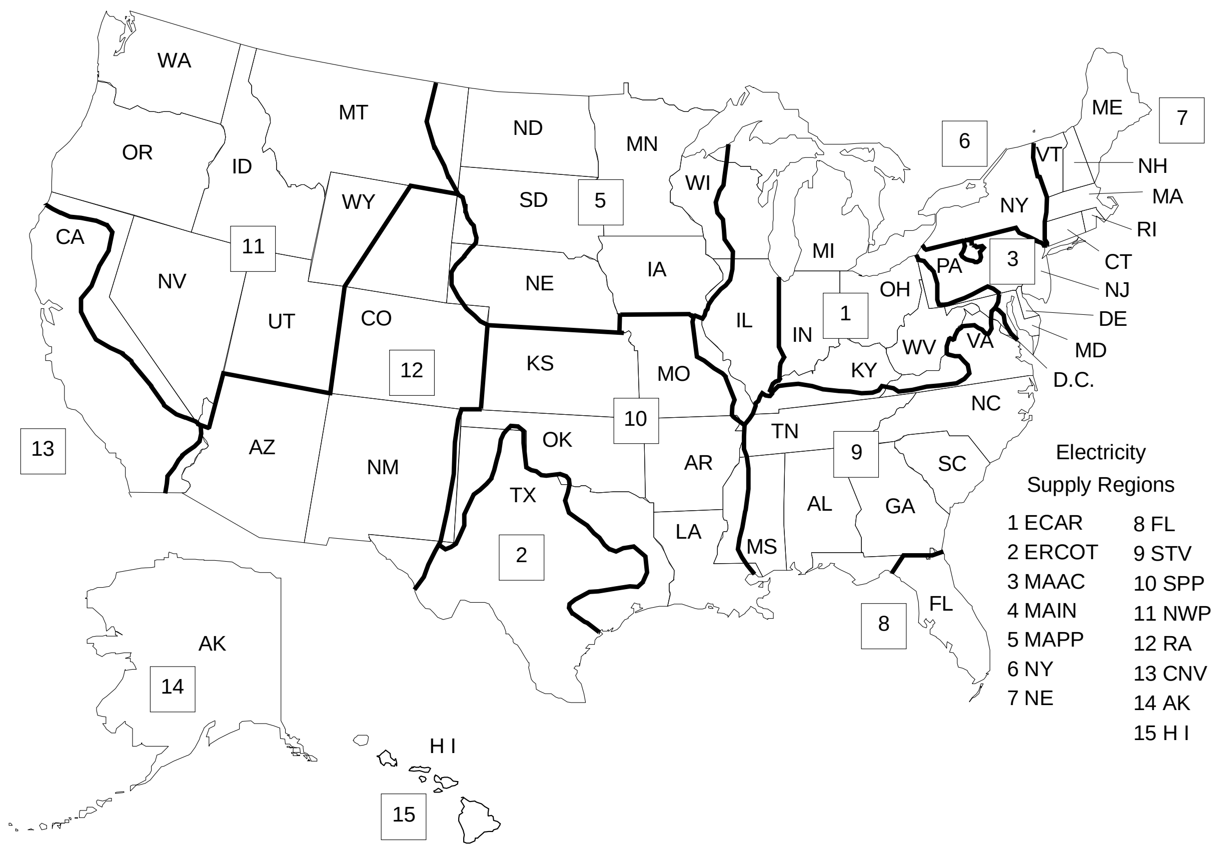
The EFD only incorporates current regulatory strategies to comply with the CAAA that can be implemented during dispatching. These include fuel switching and allowance trading. (Retrofitting units with scrubbers is represented in the ECP).

Another feature of the EFD is the ability of utilities in certain regions to engage in interregional economy transactions. In the EFD, after the original dispatch decision has been completed, utilities in certain regions are allowed to purchase surplus

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

power from utilities in neighboring regions if it is economic to do so.[3]

Figure 2. NEMS Electricity Supply Regions



2.2 Model Input and Output

The EFD requires input data from exogenous sources, other modules of the NEMS, and other submodules of the Electricity Market Module. This section contains an overview of the data flows within the EFD. A more detailed discussion of these flows, including the layout of the input files, the sources for exogenous data, and an inventory of data flows among modules are presented in Appendix A. Table 2 contains an overview of the input and common block work files for the EFD, along with a reference to the file descriptions contained in Appendix A.

2.2.1 Exogenous Inputs

The EFD requires cost and performance data for both existing and future units to complete the dispatch decision. This information is obtained from various EIA forms for existing units, in particular from the Form EIA-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants". Likewise, cost and performance data for future generating units are

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[3] Only select regions are allowed to engage in economy trade. These regions were selected based on historic trade relationships. Additional regions will be incorporated in future versions of NEMS if the potential for trade is identified.

provided by the Office of Integrated Analysis and Forcasting from discussions with various sources - industry, government and the National Laboratories, with the following specific sources -- Solar Thermal: California Energy Commission Memorandum, *Technology Characterization for ER94*, August 6, 1993; Photovoltaic: *Technical Assessment Guide-Electric Power Research Institute* (EPRI-TAG1993); MSW: EPRI-TAG 1993. Transmission constraints and trade relationships[4] are also input to incorporate economy trade.

NO_x, CO_2, Carbon, CO and VOC emission rates and ash retention rates are also provided to determine annual emissions.

Load shape information is also provided exogenously and is based on historic load shapes.

2.2.2 Inputs from Other Modules[5]

The demand modules provide electricity demand by sector. These demands are aggregated and mapped to a load duration curve in the Load and Demand Side Management submodule prior to the dispatch decision.

The commercial and industrial demand modules represent cogeneration and other electricity production at their facilities. The generation provided by these modules is converted to capacity (assuming a 100 percent capacity factor) with the resulting capacity subtracted from the load curve. Likewise, generation from renewable sources is subtracted from the load duration curve prior to the dispatch decision using capacity factors provided by the Renewable Fuels Module.

Fossil fuel prices are provided by the fuel supply modules of NEMS. These prices are used in determining variable costs for each plant type and arranging the plants in merit order.

SO_2 emissions are now provided by the Coal Market Module.

The Electricity Capacity Planning (ECP) submodule provides information to the EFD. The ECP provides the annual available capacity to be used in the dispatch decision.

2.2.3 Outputs

The EFD determines the allocation of generating capacity to meet electricity demand. The output of this decision is needed to determine the price of electricity and to account for: 1) the utilization of the fuel inputs; 2) renewable generation; and, 3) emissions. In particular, the EFP requires fuel costs and variable O&M to determine the price of electricity. The Renewable Fuels Modules is passed generation from renewable sources to compute net generation from renewable sources while the remaining Fuel Supply Modules require the amount of fuel consumed for the pricing of the fuel and for calculating "total" fuel use by all sectors. The EFD provides to the CMM regional SO2 removal rates. Emissions are provided from the CMM through the EFD to the integrating module.

Output reports provide projections of generation and fuel consumption by plant and fuel type, for both electric generation and cogenerators and interregional and international economy trade. Reports include emissions. These reports contain both national and regional projections. National projections are published in the *Annual Energy Outlook 1997* and regional projections are provided on EIA's Web Site http://www.eia.doe.gov in the *Supplement to the Annual Energy Outlook 1997*.

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[4]The transmission links tell the dispatch submodule that the region's are able to trade with each other.

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

Table 2. Summary of Data Flows in the EFD

Input File	Appendix Reference	Common	Appendix Reference	General Description
		emmparm	A2-1	EMM parameters
		parametr	A2-2	NEMS parameters
ECPDAT	A1-4	ecpcntl	A2-3	control/switch file
		ncntrl	A2-4	control/switch file
PLNTDAF	A1-1	plntcntl	A2-7	
		& plntin	A2-6	pant level information
ETTIN	A1-2			constraints file
ETTDEM	A1-3	dispett	A2-8	net flows, Can. sply curve info
& ETT$TMP				
NUGPIPE	A1-7			other cogen(not ind/comm)
SO2CNTL	A1-6	uso2grp	A2-19	SO2 limits and allowances
		dispin	A2-24	overall inputs
ELDATYR	A1-5	dispinyr	A2-9	historical data overwrites
GEODATA	A1-9	emmgeo	A2-13	geothermal and renew capy
COGENMF	A1-8	cogen	A2-12	cogen capy removed from
& Ind/Comm modules				load curve (ind/comm)
Various modules		control	A2-10	electricity demands
CMM module		coalemm	A2-5	coal prices, SO2 emissions
Various modules		qblk	A2-23	price/quantities
LDSM module		dispcrv	A2-20	load shapes
		bildin	A2-11	build info from ECP
Various modules		fuelin	A2-21	fuel quantities
		dispuse	A2-15	EFD working space
		dispout	A2-16	results of the EFD decision one region, current year (generation, cons. & emissions)
		uefdout	A2-17	Same as dispout but for all regions & years (reporting purposes)
		uettout	A2-18	trade results
		emission	A2-14	pollutant emissions
		postpr	A2-22	reporting variables

3. Model Rationale

3.1 Theoretical Approach

3.1.1 Basic Model Approach

The EFD uses an heuristic approach to provide a least-cost solution to allocating (dispatching) capacity to meet demand. Dispatching involves deciding what generating capacity should be operated to meet the demand for electricity, which is subject to seasonal, daily, and hourly fluctuations. The objective of the EFD is to provide an economic / environmental dispatching procedure. In an economic (least-cost) dispatch, the marginal source of electricity is selected to react to each change in load.[6] In environmental dispatching, the demand for electricity must be satisfied without violating certain emissions restrictions. The EFD integrates the cost-minimizing solution with environmental compliance options to produce the least-cost solution that satisfies electricity demand and restricts emissions to be within specified limits.

Environmental issues that are incorporated in the EMM-NEMS include compliance with SO_2 and NO_x restrictions specified in the Clean Air Act (New Source Performance Standards - NSPS, Revised New Source Performance Standards - RNSPS, and Clean Air Act Amendments - CAAA). The implications of Title V of the CAAA in the EFD decision-making process is discussed later in this Chapter in the Fundamental Assumptions section while the specifics of the CAAA outlined in Appendix D.

Demand can be characterized by a load curve, which is a plot of power demand (load) versus time (Figure 3). The highest point on the curve, the peak point, defines the capacity requirement. The capacity allocated to meet this last increment of demand is used infrequently during the entire period. On the other hand, the capacity assigned to satisfy demand at the base, or minimum point of the curve is required on a continuous basis. The percent of time capacity is required at each slice of load is called a capacity factor (utilization rate). The capacity factor for the load at the base of the curve is 100 percent and it approaches 0 percent at the peak of the load curve.

The relationship between capacity requirements and capacity utilization can also be illustrated by a load duration curve, which is obtained by reordering the demands for power in descending order rather than chronologically (Figure 4). This curve shows the capacity utilization requirements for each increment of load. The height of each slice is a measure of capacity, and the width of each slice is a measure of the utilization rate or capacity factor. The product of the two is a measure of electrical energy (e.g. kilowatthours). The problem is to determine which capacity types to assign to each of these slices of load, and what fuels to use in each of these capacity types (in order to represent switching in multi-fuel units).

In the EFD, there are six load curves for each region with each load curve representing two months (see Appendix A for a description of this parameter and the mapping of the seasons). Each load curve contains twenty six vertical slices, categorizing the load by magnitude (height) and time. The EFD dispatches available capacity to meet load in each of these slices. (Note, although the load curve re-orders the load segments, the chronology is maintained to represent maintenance scheduling for capacity and to model economy trade.)

The algorithm used for the dispatch decisions is straightforward. First, capacity to be dispatched is ranked from least to most costly based on the sum of fuel and variable O&M costs.[7] (Previously, this ranking of capacity also included an emission component that has now been removed from the algorithm.) Capacity is then allocated under certain considerations/constraints until demand is satisfied (i.e. engineering considerations limit the range of operation for certain capacity types and are incorporated using minimum and maximum capacity factors). Next, generation is

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

[7]Note, cogeneration and renewables (excluding hydroelectric) capacity is removed from the load duration curve prior to the dispatch decision.

determined as the corresponding area for which the capacity has been allocated using a piece-wise, linear approximation to measure this area (Figure 4). This is done for the area under the original load curve as well as for the area under a curve representing excess production that would be available for export and for an area representing generation that could be displaced by cheaper imports. The calculation to determine the levels of economy trade is then performed.

3.2 Fundamental Assumptions

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

While the marketable allowance program in the CAAA is economically attractive it is difficult to model. (See Appendix D for a summary of the relevant provisions of the CAAA.) The CAAA does not set plant specific emission rate limits. Rather, the CAAA sets national limits on the emissions of SO_2. Utilities are free to choose from a wide array of options to reduce their SO_2 emissions to the level of allowances allotted to them. Among the major options available to utilities are switching to the use of lower sulfur fuels, reducing the utilization of their relatively high emission units while increasing the utilization of their low emission units, adding emissions reduction equipment at some generating facilities, purchasing additional allowances from others or purchasing power from utilities in neighboring regions which have lower emissions. Thus, representing utility efforts to minimize their costs of complying with the CAAA requires a complex nationwide analysis.

The EFD includes operating options for reducing emissions, which are based on short-term, operating (fuel and variable O&M) costs. During dispatching, emissions can be reduced by switching from fuels with "high" emission rates to fuels with "low" emission rates. This includes now only interfuel switching (intrafuel switching within coal sulfur types is now accomplished within the CMM). For example, required reductions in SO_2 emissions can be accomplished by decreasing utilization of coal- or oil-fired units with comparatively high emission rates by increasing the utilization of capacity types that emit little or no SO_2 (gas-fired, nuclear, and renewable plants). This 'fuel-switching' option is also available through interregional economy trade; i.e., a utility may lower its emissions by purchasing surplus power from a utility in a neighboring region which has lower emissions.

For each of the 13 electricity supply regions, the EFD also represents trading of SO_2 allowances. That is, utilities with relatively low costs of reducing emissions may overcomply (i.e. reduce emissions beyond their required level) and sell their excess allowances to utilities with comparatively high reduction costs. This trading of allowances assumes that the market for allowance trading is 'perfect', i.e. is based only on a cost saving. However there are other factors involved in allowance trading which are not currently incorporated i.e., local pressure for utilities to reduce emissions in place of purchasing allowances. On a national level, allowance trading does not lower total emissions but it reduces the overall cost of achieving the specified emissions target.

There are also assumptions regarding both the supply and demand for electricity in the EFD, particularly related to aggregation issues. On the supply side, forced outages are assumed to occur randomly with the amount of capacity that is out-of-service at any given time as the expected value. Also, utilities in each of the 13 electricity supply regions are operated as a "tight" power pool. This aggregation of generating capacity does not address transmission and other engineering constraints that may limit dispatching of particular plants. Therefore, intra- regional trade can not be incorporated. Also, unit level information is not maintained so projections by unit, utility or State (except New York and California) are not available. Only aggregate results are available (by region and for the Nation). On the demand side, the load duration curve aggregates loads from many utilities to 26 points per season and region. This may not fully represent load variations, however, the aggregation is necessary due to time and resource (particularly computer resources) constraints.

Figure 3. Typical Load Curve

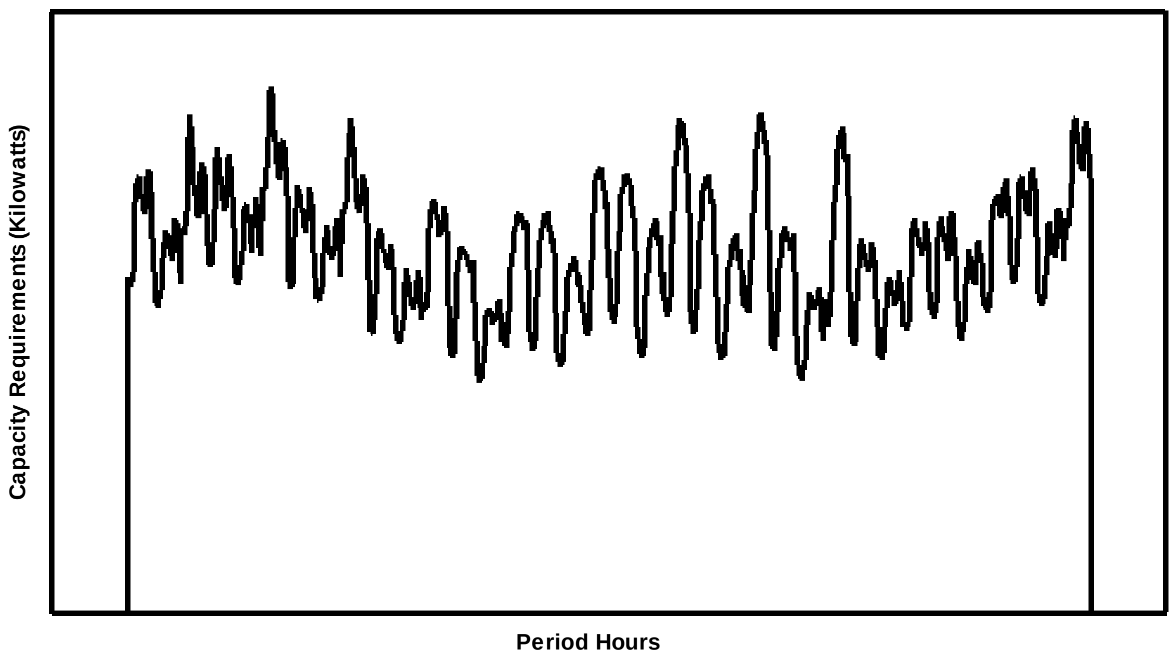
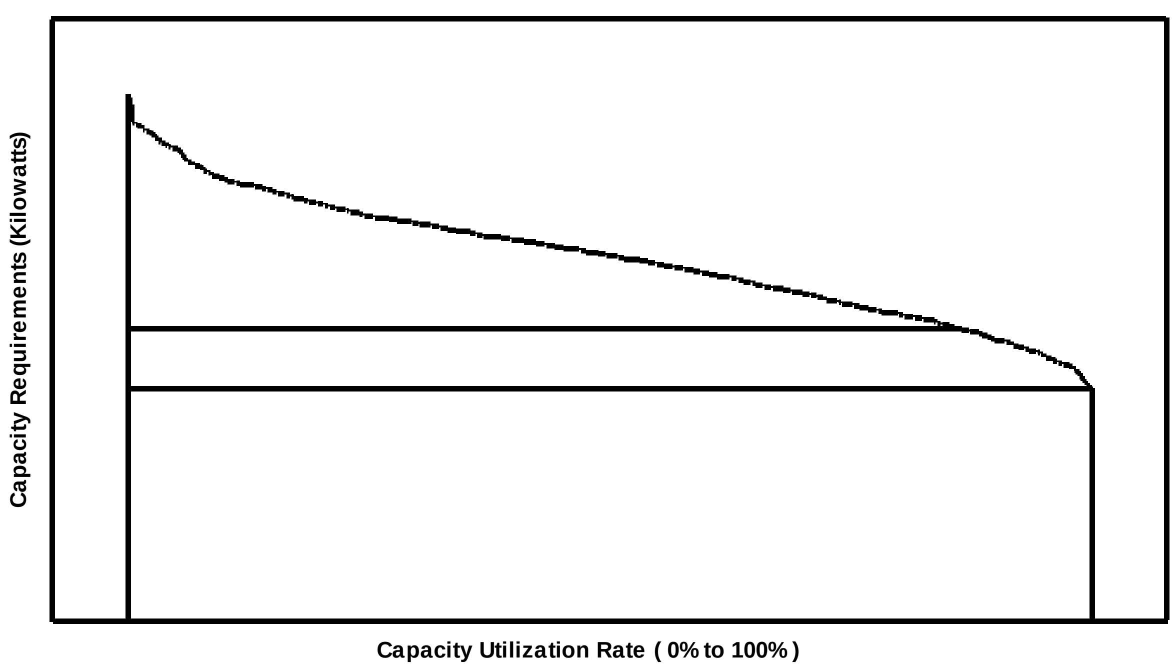


Figure 4. Typical Load Duration Curve



3.3 Alternative Approaches

Early in the NEMS development process, models from other organizations were reviewed as possible methodologies for modeling the dispatch decision in NEMS (including trade and nonutility supply). This section outlines the results of this study, including the reasons for not choosing the methodology discussed.

3.3.1 Modeling the Dispatch Decision

A Lagrangian approach[8] is used in the dispatch decision in NEMS. The Lagrangian approach was chosen because of its quick execution time and ability to manage many intervals for approximating the load duration curves. An LP approach was considered, however, LP models require a considerable execution time and storage.

A variety of models that evaluate methods for reducing emissions have been reviewed[9]. These models can be classified into three categories: planning models, site-specific air pollution models, and environmental impact screening models. Several of these models examine environmental issues and regulations that are required to be included in the EFD.

Three models use a linear programming methodology to represent acid deposition control. The Electric Power Research Institute (EPRI) uses its Electricity Generation Expansion Analysis System (EGEAS) model to determine the impacts of emissions on air and water quality. ICF Incorporated employs a linear programming approach in two models—the Integrated Planning Model (IPM) and the Coal and Electric Utilities Model (CEUM), which was originally derived from the NCM. Two other systems, Energy Management Associates' PROMOD III and Argonne National Laboratory's Argonne Utility Simulation (ARGUS) model, incorporate emissions limits on pollutants such as SO_2 and NO_x by including an emissions cost in the cost function.

None of these models are integrating systems consisting of a comprehensive set of supply and demand models. In some cases, there is a detailed representation of coal supply but few, if any, linkages to other fuel supply, energy conversion, or end-use demand modules as required for the NEMS. Some of the environmental models are designed to evaluate individual power pools, utilities, and generating units because the absence of detailed representations for other energy markets allows them to concentrate on the electric utility industry. However, the level-of-detail and system resources allocated exceed the corresponding requirements for a single sector within the NEMS so these models cannot be considered candidates for the EFD.

The LP model which was considered for inclusion in the EFD is similar to the EGEAS, IPM, and CEUM models. The heuristic procedure chosen uses an emissions penalty cost that resembles the emissions cost used in the PROMOD III and ARGUS models. In order to meet the system requirements for the NEMS, the approach in NEMS needed to be considerably smaller in size and scope than the environmental models reviewed.

3.3.2 Representation of Trade

Several electric utility models were examined to determine their potential for analyzing bulk power economy transactions. (See the ECP Documentation for a discussion of methodologies for firm power transactions.) These include:

- **Gas Research Institute (GRI); GRI Baseline Projection Methodology**

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

[9] A more detailed discussion of environmental models is contained in the draft report *Environmental Modeling Review Acid Deposition Control*, prepared by the Decision Analysis Corporation and ICF Resources Incorporated, Contract No. DE-AC01-87EI19801, July 31, 1991.

- **ICF Resources, Inc.; Electric and Gas Utility Modeling System (EGUMS)**
- **DRI/McGraw Hill**
- **U.S. Department of Energy, Office of Policy; FOSSIL2**
- **Argonne Laboratories; Argonne Utility Simulation Model 1992 (ARGUS92)**
- **Bonneville Power Authority; Power Market Decision Analysis Model (PMDAM)**
- **American Gas Institute (AGI).**

FOSSIL2, AGI and DRI do not currently model transmission or trade and will not be described further. The following models and utilities have bulk power economy transfer modelling capabilities which were considered for NEMS:

<u>GRI; Baseline Projection Methodology</u>

GRI represents firm and economy bulk power sales in its Baseline Projection Methodology in a similar fashion as in the EMM.[10] Firm and economy power sales are determined in the capacity and generation submodels (comparable to the EMM's electricity capacity planning and fuel dispatch submodules) of the Electric Utility Sector Model (comparable to the EMM).

Economy power sales are only represented in the NERC Western Systems Coordinating Council (WSCC) region where bulk power is transferred into California from the other three WSCC subregions. Generation is committed for sale to California after the baseload units have been dispatched, but before the generation at oil- and gas-fired peaking units has been determined.

Interregional transfers of power are priced in two ways. First, an exogenous input price for existing purchase power agreements is used for the known firm interregional transfers. Next, for model determined power purchases, the importing region's avoided cost is used. The regional avoided cost is calculated using the regional variable cost of electricity, regional net interchange cost of supplying electricity, and a regional loss factor.

The methodology to determine interregional transfers is similar to that in the EFD. Both models represent economy sales competing in the dispatch component. However, the EFD represents economy power sales in various regions (instead of just in WSCC) and contains a database summarizing existing and currently planned transactions by electric utilities. The EFD also represents international trade.

<u>ICF Resources, Inc.; Electric and Gas Modeling System (EGUMS)</u>

EGUMS, a linear programming model, endogenously represents economy trade.[11] Eleven regions are represented in the model. These are the North American Electric Reliability Council (NERC) regions, California, and Florida. The model determines supply and demand for electricity on a regional level with the option for demand to be met using electricity supplied from another region, constrained by transmission capacity; i.e., dispatch decisions are made using the least cost plant (and other factors) regardless of where that plant is located so long as the interregional links to carry power have not reached their capacity.

Current and future transmission constraints are determined using NERC publications and discussions with reliability council members. ICF also assumes that the advantage of increased interregional trade does not

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[10]Gas Research Institute, *1987 GRI Baseline Projection Methodology*, (Chicago, IL, December 1987) and conversations with Paul Holtberg of the Gas Research Institute.

[11]ICF Resources, Incorporated, *The EGUMS Supply Model*, (Washington, DC).

balance the additional cost for building new transmission capacity, so expansion to the transmission system (besides that reported in the NERC publications) is not modeled.

EGUMS prices these interregional flows by splitting the difference between the regional marginal variable costs in the regions involved in the trade. There is no representation of transmission costs; only variable generation costs are used in this calculation. This split in the marginal costs is treated as a cost to the receiving region and a revenue to the selling region.

This methodology is similar to the EFD; however, international trade is represented in the EFD while it is not represented in the ICF model. Also, firm power commitments are represented in the ECP while the ICF model does not represent firm power trade at all. Historically, firm power sales and international trade have played a significant role in some regions of the country.

Argonne Laboratories; ARGUS92

The Argonne Utility Simulation Model 1992 (ARGUS92)[12] does not explicitly model bulk power trade. It is possible to determine intraregional trade in the model by comparing a given State's demand and generation. The difference represents the level of intraregional economy trade for that State.

Interregional trading is represented by exogenous inputs. Historic values between regions are assumed to remain constant. No distinction has been made between firm and non-firm trades.

Bonneville Power Authority; PMDAM

The Bonneville Power Authority (BPA) owns and operates the major transmission lines within the Pacific Northwest and interconnects with utilities in California, the Pacific Northwest and British Columbia. BPA markets wholesale power in the Pacific Northwest. BPA does not own or operate any generating plants but facilitates the development of generating resources through contracts to purchase and market power. To help in BPA's market strategies and long-term power sales decision, the BPA developed the Power Market Decision Analysis Model (PMDAM).[13]

PMDAM simulates the West Coast wholesale power market, representing both the physics of the electric power system and the economics of trade in the West. PMDAM assumes that each utility attempts to find the least-cost plan to serve its native load. Each utility is represented by a distinct objective function, discount rate and environmental preference (i.e. utilities have different environmental standards). The model determines the economics of the system operations on an hourly basis, which is then aggregated to a daily, weekly, monthly and annual solutions.

As stated, PMDAM's planning objective is to meet firm capacity and energy requirements while minimizing each party's total fixed and variable costs. The model is dimensioned by region (regions are aggregates of the individual utilities on the West coast; a region may be represented by only one utility), time (hourly, daily, monthly, etc.) and uncertainty (hydro inflow, native load, natural gas price and generating unit forced outage). The decision variables are financial, reliability and environmental balances within the electric power system in the West with the electric power system represented by its basic physical elements including the individual loads, generation and transmission systems and power contracts. These physical elements form a system of thousands of nonlinear, simultaneous equations which determine the quantities, costs, prices and opportunity costs of the system operations. The opportunity costs (shadow prices) of each constraint in the model (transmission, hydro operation, firm capacity and energy, etc.) represents the change in a utility's total cost for a unit change in the constraint. The model requires an iterative process because the supply and demand

[12] Argonne National Laboratory, *Introduction to the Argonne Utility Simulation (ARGUS) Model*, (Argonne, IL, March 1990).

[13] Bonneville Power Administration, *The BPA Power Market Decision Analysis Model: Methodology Report*, (Portland, OR, July 24, 1991).

balance among utilities depends on price while the price depends on the cost of supplying power at a given level of demand.

PMDAM models uncertainty using the Monte Carlo method, i.e. the model is run for several "games" with the likelihood of each game equal. For each game, the probability distributions are used to determine levels for each variable.

Although PMDAM models both the physical and economic considerations of transmission and trade, it is too complex and detailed for NEMS. Also, EIA does not have data to support such a detailed model.

3.3.3 Modeling the Development of Nonutility Power Projects

Currently, many forecasting organizations do not explicitly represent IPP and SPP projects in the capacity planning algorithm, rather they use a simplistic market sharing approach to estimate nonutility development. Cogeneration is generally represented in the industrial or commercial sectors.[14] This methodology is used to forecast IPPs and SPPs because of the lack of project financial and performance data for such facilities. EIA has recently conducted a study to acquire this data from electric utilities, equipment vendors and financial institutions.[15] This information has been incorporated into NEMS.

An exception to this lack of data is the Applied Energy Services Corporation (AES), a nonutility developer, which uses financial and performance assumptions derived from their own project experience. AES has prepared several different nonutility supply models which vary by application. For the Department of Energy and the Gas Research Institute, AES developed Fossil2 and the Nonutility Generation Simulation Model (NUGSM), respectively. Although some of the detail in the models is different, the overall methodology of the modeling systems is similar. AES also developed models for the Bonneville Power Administration and for individual utilities to forecast nonutility potential in their service areas. A more detailed description of each AES modeling system follows. Because of the similarity between Fossil2 and the Nonutility Generation Simulation Model, the models are described together.

In Fossil2 and NUGSM,[16] the electricity sector determines new capacity needs based on forecasted load growth. Utility-owned combustion turbines and storage are used to fill peaking requirements. The remaining utility and nonutility technologies compete to meet the system's intermediate and baseload requirements. Only IPPs and SPPs compete in the electricity sector, while cogenerators are accounted for in the Industrial Sector.

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[14] Nonutility supply is referred to by various terms depending on the ownership and type of facility. Small power producers (SPP) are facilities as defined under the Public Utility Regulatory Policies Act of 1978 (PURPA) in which renewable sources provide at least 75 percent of the total energy input. Renewable sources include solar, wind, biomass, waste, geothermal and water (hydroelectric). Independent and affiliated power producers are facilities whose primary function is to produce electricity for sale to utilities (i.e., they are not involved in any industrial or other processes).

Exempt wholesale generators (EWGs) are functionally the same as IPPs/APPs but with a clear, regulatory definition for the corporate ownership of the projects . Prior to EPACT, competing in the wholesale generation market (under the Public Utility Holding Company Act) was restricted. EPACT reformed PUHCA allowing greater access to the wholesale electricity market without stringent Securities and Exchange Commission oversight.

[15] Deliverable Number 4 under Washington Consulting Group Task 92080, "Evaluation of Differences in Electric Utility versus Nonutility Projects", July 13, 1992.

[16] Prepared by Applied Energy Services for the Department of Energy, *The National Energy Strategy Integrating Energy Model - Fossil2* and the Gas Research Institute, *Nonutility Generation Simulation Model*, Arlington, VA, (October 1991).

A logit-based market penetration algorithm determines the nonutility market by comparing the nonutility's levelized costs to the utility's avoided cost for the least-cost baseload technology. Likewise, a least-cost mix of nonutility technologies is then chosen to fill this market share (up to a user-specified cap), with utility technologies filling the remainder of new capacity needs. Avoided cost payments to nonutilities are treated as allowed expenses in the model.

In the Non-Utility Generation Model (NUGM) developed by AES for the Bonneville Power Administration (BPA) nonutility generation is projected as a function of utility avoided costs, industrial electricity prices, and retail electricity prices.[17] NUGM is a submodule of BPA's Conservation Policy Analysis Model (CPAM) and can also be used as a stand-alone model. Information on the resource potential at industrial facilities in the Northwest used in NUGM is from the report, *Assessment of Commercial and Industrial Cogeneration Potential in the Pacific Northwest.*

First, the CPAM determines the need for new resources. If a utility has surplus generating capability, CPAM sets the avoided cost to its marginal energy cost. Renewable small power producers are represented in the appropriate renewables submodules.

NUGM allows the utility to either post its avoided cost and see how much nonutility generation evolves in its service area at that price or it can use formal bidding to acquire new resources. Under a posted avoided cost policy, all projects which are economic at less than the avoided cost will be initiated. Under the bidding policy, only the least cost alternatives are accumulated and charged to the utility as purchased power payments. These payments are used in CPAM to calculate utility operating costs and electricity rates.

In addition to AES, the General Electric Company (GE), an equipment developer and servicer for generating units, models nonutility supply in order to determine future orders of generators.[18] The GE model is composed of several submodels which interact sequentially. These models are: Economic, QF filing, Order, Classification and Installation. The Economic Model involves a yearly evaluation of the economics of eight representative nonutility technologies: five cogeneration technologies, one SPP and two IPPs. The QF Filing Model evaluates qualifying facilities in terms of the magnitudes and relative yearly changes in QF filings for each year (IPPs are not evaluated in this model.) Next, the Order Model performs linear regressions on the minimum yearly payback values for qualifying facilities and on the maximum return on equity for IPPs resulting in estimates of equipment orders. These orders are arranged by application (cogenerators or SPP), location (NERC region) and technology in the Classification Model and evaluated by utility regional capacity needs. The Installation Model forecasts the scheduling of the installation of the equipment orders.

The Data Resources Incorporated (DRI) compete IPPs and qualifying cogenerators with utility units. As in NUGS, the differences between IPP and utility units are reflected in their capital structures. Cogenerators are forecasted based on non-electric production at the facility, the price of natural gas, and avoided cost calculations. SPPs are modeled exogenously. DRI uses Edison Electric Institute data for its historical base. North American Electric Reliability Council (NERC) data are evaluated to estimate viable projects for its planned capacity additions.

The American Gas Association uses a market share approach for IPPs and SPPs and uses the historical relationship between the use of heat, light and power in a facility to estimate generation at projected facilities.

NERC also prepares projections of nonutility development. Each year NERC aggregates the forecasts of its

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[17]Prepared by Applied Energy Services and the University of Southern California under contract to Bonneville Power Administration (Contract number DE-AM799-88BP3721), *Dynamic Analysis of Pacific Northwest Non-Utility Power Generation,* September 1990.

[18]The General Electric Company, *The Non-Utility Generation Market for the 1990's: A Comprehensive Economic Model-Based Forecast,* December 1991, (Schenectady, New York).

nine Regional Reliability Council's, which are in turn, aggregates of individual utility forecasts.[19] NERC does not explicitly model the electric utility industry, it aggregates utilities' resource plans.

The Bechtel Power Corporation forecasts assume that a share of new supply will be met by nonutility supply (approximately 40 percent) based on analyst judgement.

AMOCO also projects nonutility supply to determine fossil-fuel consumption. AMOCO uses EEI data for its historical base and NERC projections for planned additions. AMOCO's nonutility supply forecast is based on historical trends and analyst judgement.

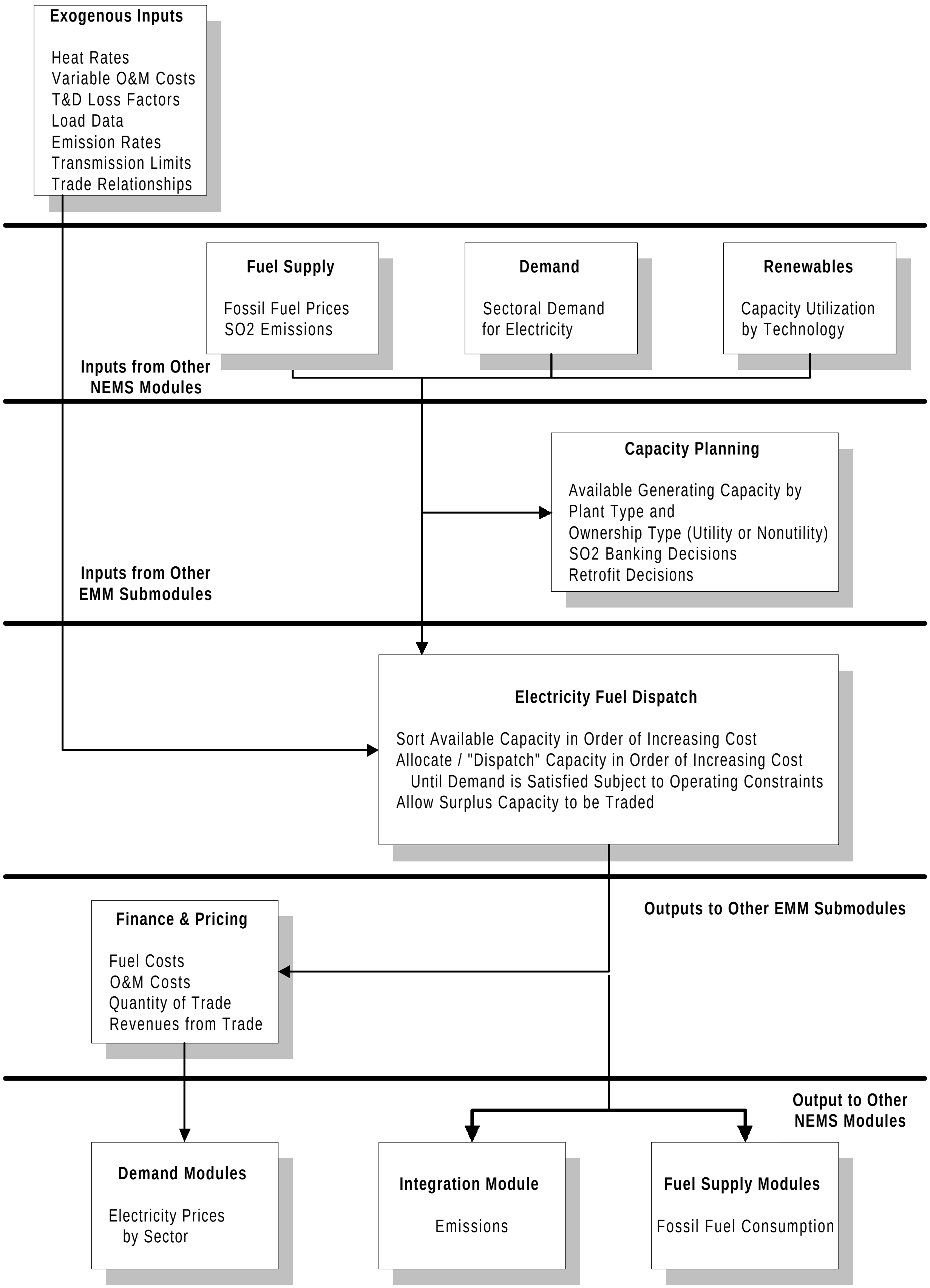
[19] North American Electric Reliability Council, *Supply and Demand 1991-2000*, July 1991.

4 Model Structure

4.1 Logic Flow

Figure 5 is a flow diagram for the EFD. This flow chart includes: major exogenous inputs, inputs from other modules (both NEMS and other submodules of the EMM), and the model outputs and the destination for this information.

Figure 5. EFD Data Inputs and Outputs



4.2 Key Computations and Equations

This section provides the mathematical specification of the EFD. The heuristic approach is a modified version of the dispatching components of the EMM-IFFS[20]. As in IFFS, the EFD continues to rank available capacity in a least-cost manner and to dispatch capacity in this order until demand has been met (subject to certain operating and engineering constraints, discussed in detail in the Solution Technique section). Improvements to the approach include: 1) the incorporation of better representation of the Clean Air Act Amendments of 1990 (CAAA); 2) the alternative representation of the load duration curve to better represent demand; and 3) the implementation of economy trade.

The objective of the EFD is to provide an economic/environmental dispatching procedure. In an economic (least-cost) dispatch, the marginal source of electricity is selected to react to each change in load.[21] In environmental dispatching, the demand for electricity must be satisfied without violating certain emissions restrictions. The EFD integrates the cost-minimizing solution with environmental compliance.

Environmental issues incorporated into the NEMS include compliance with SO_2 restrictions specified in the CAAA. Strategies for complying with the CAAA that are represented in NEMS include retrofitting existing capacity with pollution control equipment, fuel switching and trading of emissions allowances. These options are a combination of planning and operating decisions. Planning decisions typically involve changes in capital stock and require a longer time horizon and substantial capital investment. They are based on a life-cycle cost analysis that examines the tradeoff between investment and operating costs. Retrofitting existing units with scrubbers is considered a planning operation for reducing emissions of SO_2. This decision to install a scrubber, which would allow the use of a lower-cost, higher-sulfur fuel, depends on whether the savings in fuel costs offset the initial capital investment. The results of planning decisions that are made in the ECP submodule are reflected in the dispatch decision. For example, a coal-fired unit that has been retrofitted with a scrubber because of an earlier planning decision will have a lower emission rate than a coal-fired unit without a scrubber.

The EFD includes operating options for reducing emissions, which are based on short-term, operating (fuel and variable O&M) costs. During dispatching, emissions can be reduced by switching from fuels with "high" emissions rates to fuels with "low" emission rates. This includes now only interfuel switching (intrafuel switching within coal sulfur types is now accomplished within the CMM). For example, required reductions in SO_2 emissions can be accomplished by decreasing utilization of coal- or oil-fired units with comparatively high emission rates by increasing the utilization of capacity types that emit little or no SO_2 (gas-fired, nuclear, and renewable plants).

On a national level, allowance trading does not lower total emissions but it reduces the overall cost of achieving the specified emissions target.

The approach to incorporate domestic economy trade into the NEMS is to extend the EFD to include the additional supply option of "dispatching" (i.e. purchasing) capacity in one region to serve a different region's demand. Several extensions to the EFD were made:

- **The load representation preserves additional chronological information to allow for energy**

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

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

purchases from extraregional utilities within physical limits of the transmission system (the requirement was to be able to match the blocks of energy available in the exporting region to the simultaneous need for power in the importing region.)[22] This is accomplished with a modified load duration curve which describes the seasonal, day-of-week and time-of-day variations in the demand for electric power.

- **The solution algorithm of the EFD computes the marginal costs associated with the surplus capacity in the exporting region, and to maintain this information to determine the savings from interregional trade. In other words, once the EFD regional utilization of capacity has been determined without allowing interregional trade, then a second stage process is used to refine the economic dispatch taking into consideration the opportunities and constraints associated with interregional trade.**

- **In the EFD, merit ordering of resources to meet demand simply includes ranking capacity from the least cost to the most costly and selecting the capacity from the rank ordering necessary to meet each region's demand. In the second stage, the merit ordering of resources is redone for selected importing regions (pre-determined), including the exporting region's surplus capacity in the dispatch decision.**

- **The initial implementation of interregional trade options are allowed for pre-determined importing and exporting regions. The regional dispatch decision processes the exporting regions first, followed by the importing regions, ordered from highest to lowest marginal cost. The EFD then attempts to improve the importing regions solution by substituting capacity from the exporting regions. This approach allows exporting regions to supply power to multiple importing regions by allocating the capacity to the importing region with the highest marginal cost first, and then to other, less costly regions. This approach limits both the processing burden of representing trade and maintaining the information required to measure the savings resulting from trade.**

- **The limits on total energy available during each demand slice are applied to restrict trade by the transmission line constraints.**

- **Additional transmission costs and energy losses are assigned to the exported power.**

- **Once a level of economic transfers has been identified by the EFD, the "savings" are allocated (currently split evenly) between the importing and exporting regions and between consumers and investors.**

4.2.1 Solution Technique

Figure 1 provides an overview of the steps involved in the dispatch algorithm. Initial operating costs (fuel and operations and maintenance expenses) are accumulated by plant groups. The merit order is then determined by ranking the groups in ascending order of the total variable costs.

The total cost for plant operations determines the merit order. This approach yields dispatch decisions that provide the lowest operating cost. Using this merit-order, available capacity is then allocated to meet demand for electricity represented by the load duration curve. During dispatching, engineering considerations that may limit the range of operation for a given capacity type are incorporated using minimum and maximum capacity factors. For instance, nuclear units are not allowed to operate as peaking capacity because they cannot be started or stopped quickly. The operating range is represented by a set of trigger points that identify the point(s) on the y-axis that corresponds to the capacity factor limits. As each plant type in the merit order is

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

allocated, the algorithm checks to insure that the corresponding trigger points are not violated.

When a given plant type has been allocated, the next step is to determine the generation, which is represented by the corresponding area under load duration curve. A piece-wise, linear approximation to the load duration curve is used along with a series of vertical slices so that the area under the curve is represented by a succession of trapezoids. This eases the computational burden for determining the area. For each plant type, fuel consumption is computed by multiplying generation by the fuel share and heat rate for each fuel. (Emissions are still calculated here, but for cross-checking purposes only now, as the product of fuel consumption and the corresponding emission rate, accounting for any reduction resulting from pollution control equipment).

The solution to the economic/environmental dispatch problem is achieved then the economy trade algorithm is performed. This algorithm includes pre-determined importing and exporting regions. It attempts to improve the importing systems solution by substituting less expensive capacity from the exporting systems by allocating the capacity to the importing system with the highest marginal cost first, and then to the other, less costly systems. It does this amongst load slices representing the same season and time-of-day.

The following provides the mathematical specification of the EFD's solution algorithm.

Dimensions

e	=	EMM electricity supply region providing electricity for sale to another region.
y	=	Years in the planning horizon
r	=	EMM electricity supply region
i	=	Capacity type
f	=	Fuel choice
h	=	Vertical load steps which define total electricity load
s	=	Season

Decision Variables

A_{rsih}	=	Assignment of Plant i in Season s and Region r to Load Slice h (i.e. fraction of load slice h satisfied by plant i)
M_{sri}	=	Average Capacity Out of Service in Season s for Planned Maintenance for Plant i in Region r (kilowatts)
S_{rif}	=	Fuel Share of Fuel f for Plant i in Region r (fraction)
EA_{rsieh}	=	Assignment of plant i in season s and region e to serve load slice h in region r (fraction of load slice h in region r satisfied by plant i in region e)

Input Requirements

Electricity Demand

E_{rs}	=	Demand for Electricity in Region r and Seasonal Period s (billion kilowatthours)
C_{rsh}	=	Capacity Factor for Load Slice h in Region r and Seasonal Period s (fraction)
D_h	=	Height of Load Slice h (kilowatts)

Thus, Generation Requirements are:

$$\sum_s \int_h C_{rsh} * D_h = \sum_s E_{rs}$$

Fuel Specific Information

P_{rf}	=	Price of Fuel f ($ per million Btu)
T_{rf}	=	Quantity of Sulfur Dioxide per Unit of Fuel (pounds per million Btu)
EP_{rf}	=	SO_2 Emission Price ($ per ton) - calculated in the CMM and passed to EFD

Plant Specific Information by Capacity Grouping

R_{ri}	=	Planned Maintenance Requirement for Plant Type i and Region r (kilowatts)
H_{rif}	=	Heat rate for Fuel f used in Plant Type i and Region r (Btu per kilowatthour)
X_{rif}	=	Maximum Allowable Fuel Share for Fuel f in Plant Type i and Region r (fraction)
O_{rif}	=	Variable Operations and Maintenance Cost using Fuel f in Plant Type i and Region r (mills per kilowatthour)

Transmission Specific Information

EJ_{re}	=	Transmission and Distribution loss factor for energy transmitted from region e to region r (fraction)
EK_{rie}	=	Total derated capacity (i.e. accounting for forced outages and transmission and reliability losses) of plant type i in region e to serve load in region r (kilowatts)

Emission Costs Information

EC_{rif} = $H_{rif} * S_{rif} * T_{rif} * (1 - B_{ri}) * EP$

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

Objective Function

The objective function for the merit-order dispatching algorithm minimizes total operating (fuel and variable O&M costs by first deciding the least-cost fuel mix for each plant and then deciding which plant type(s) to assign to each slice of load. After the initial capacity allocation, plants are flagged as surplus to a region and are allowed to be dispatched by another region. In mathematical terms, the objective function for the

purchasing region is:

Minimize

$$\Sigma_r\Sigma_s \int_h \Sigma_i[\{\text{Min } \Sigma_f (O_{rif} + H_{rif} \cdot S_{rif} \cdot P_{rf}/1000 + EC_{rif})\} \cdot A_{rsih}] \cdot C_{rsh} \cdot D_h.$$
$$+ \quad \Sigma_r\Sigma_s \int_h \Sigma_i[\{\text{Min } \Sigma_f (O_{rif} + H_{rif} \cdot S_{rif} \cdot P_{rf}/1000 + EC_{rif})\} \cdot EA_{rsih}] \cdot C_{rsh} \cdot D_h.$$

In this equation, the quantity ($O_{rif} + H_{rif} \cdot S_{rif} \cdot P_{rf}/1000$) represents the variable O&M and fuel costs (dollars per thousand kilowatthours) for a particular plant type i in region r; (likewise for plants in region e, which are generating electricity for sale to utilities in region r). The fuel shares S_{rif} specify the fraction of time alternative fuels are used in multi-fuel units. This accounts for fuel switching due to changes in the relative fuel prices or seasonal availability of fuels. For example, utility consumption of natural gas is limited in some regions during the winter because residential customers have priority over available supplies. Even though the price of gas may be less than the price of residual fuel oil, utilities may be unable to burn gas exclusively in dual-fired oil/gas plants. The variable cost is minimized by using the least expensive fuel as much as possible.

Multiplying per unit variable costs by A_{rsih} produces a weighted-average operating cost, which is then multiplied by C_{rsh} $*D_h$, which corresponds to the area (energy) for load slice h. This result represents the total cost of generations for that slice. Within each region and season, the operating costs are then summed over all capacity types and slices under the load duration curve to produce the total operating cost associated with the energy requirement.

Right Hand Side Values

ETL_{yre} = Transmission capacity limits from region e to region r in year y (megawatts).

Existing and planned transmission capacity limits are placed on the trade decision variables (using NERC data). These constraints may be relaxed in the future if transmission modeling is incorporated.

Constraints

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

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

   $\Sigma_s M_{sri} \geq R_{ri}$ $\qquad\forall$ **r and I**

2) **Allocated capacity cannot exceed available capacity, accounting for planned maintenance.**

   $\int_h A_{rsih} \cdot D_h + M_{sri} \leq K_{rt}$ $\qquad\forall$ **r, s and i**

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

   $S_{rif} \leq X_{rif}$ $\qquad\forall$ **r, s and i**

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

   $\Sigma_f S_{rif} = 1$ $\qquad\forall$ **r and i**

5) **Generation requirements must include transmission and distribution losses**

$\int_h C_{rsi} \cdot D_h = E_{rs} / (1-J_r)$ $\forall$ r and s

This objective function is subject to the following transmission related conditions and constraints:

6) **Each load slice must have capacity assigned to completely satisfy its energy requirements. That is, a region's energy requirement is met by the amount of domestic capacity assigned to meet load plus the amount of energy assigned for sale to region r from region e.**

$\Sigma_i (A_{rsih} + EA_{rsieh}) = 1$ $\forall$ r, e, s and h

and, in the exporting region e, its energy requirements is completely satisfied by the amount it assigned to meet demand less the amount assigned for sale to another region r.

$\Sigma_i (A_{esih} - EA_{rsieh}) = 1$ $\forall$ r, e, s and h

7) **Transmission constraint**

The amount of capacity that can be assigned in region e to meet demand in region r is constrained by the interregional transmission capacity limit.

$\int_h \Sigma_i (EA_{rsieh}) \cdot \Sigma_i EK_{rie} \leq ETL_{yre}$ $\forall$ r, e, s and h

Appendix A

This appendix contains a detailed description of the inputs, outputs and 'working' files of the Electricity Fuel Dispatch Submodule (EFD). An overview of the model inputs and outputs is provided in the body of the report, under the title, "Model Input and Output". The Model Input and Output section also has a listing (Table 2) of the files and common blocks which contain the data needed for the EFD. The following section describes these files in detail.

This appendix is organized as follows: First, the common blocks which contain the parameters used in the model are described (Tables A-1 and A-2), followed by a mapping of the parameter values which pertain to the EFD. Next, two control files are provided (Tables A-3 and A-4) which include the switches which turn modules and/or algorithms on or off and additional parameters. The exogenous model input section follows which contains the files and common blocks (Table A-5 through A-17) which serve as input to the EFD. Two of these files also serve as "working" files (LOADDAF/Table A-5, PLANTDAF/ Table A-6) where information is also passed from other modules or where results are saved. Tables A-18 through A-20 outline inputs from other NEMS modules. Tables A-21 through A-25 are output/work files which serve as input to other modules and/or are used for reporting purposes.

Note, in files and common blocks which are used by various modules, only the variables used in the EFD are described in detailed.

A.1 Inventory of Input Data

TABLE A1-1: PLNTDAF File Description

This file contains the unit level data from a combination of the F860, F767, F867, F423, and the F759. The pre-processor **prepplt.f** reads in only specific information from the PLNTF860 and the PLTDATA input files and compiles the information into this direct access file (DAF), a computer only readable format. For a description of the list of variables read in and used in the model see the common **plntin** Table A2-6. New units are added to this file as determined by the ECP module. This is the source of EFD and ECP capacity data.

TABLE A1-2: ETTIN File Description

This file contains region to region constraints for the years 1990-2020. The pre-processor **prepett.f** reads in the following 4 main input files. It uses the CNSRNT file, subtracts out Firm Power Contracts from the ETCNCT file, and outputs the result in the ETTIN file.

Variable Name	Columns	Description	Units	Format	Source
IRGEX	1-4	Export Region	Numeric	I2	Assumption
IRGIM	5-8	Import Region	Numeric	I2	Assumption
IYR	9-12	Year	Numeric	I1	Assumption
PTHRESH1	14-18	Price Thresholds	Numeric	F5.3	OE-411
PTHRESH2	19-23	Price Thresholds	Numeric	F5.3	OE-411
CNSTRNTS		Constraint by seasonal period	Numeric	6F7.3	OE-411

Notes: OE-411: DOE Form OE-411, "Coordinated Bulk Power Supply Program Report".
NEMS use = Output from ETT Pre-processor and Input to the EMM.

TABLE A1-2a: FRMCHRG File Description (prepett.f Main Pre-Processor Input File**)**
This file contains the fixed and variable demand and energy costs data for firm contracts. The pre-processor **prepett.f** reads it in with an unformatted read.

Description	Units	Variable Name	Indices
Fixed demand charges	Numeric	FRMFCST	(RGN,YR)
Variable energy charges	Numeric	FRMVCST	(RGN,YR)

TABLE A1-2b: CANSPLY File Description (prepett.f Main Pre-Processor Input File**)**
The Canadian Supply file is predominantly used for input to the pre-processor **prepett.f**. The input information is used in the competition between U.S. capacity and Canadian firm power imports. Its role is discussed in Section I of the report.

Variable Names	Columns	Description	Units	Format	Comments	Source
SPCNRGN	9-12	Canadian Reg (Sell)	Numeric	F4.0	UCI$CRG	Assumption
SPNEMS	18-21	NEMS Region (Buyer)	Numeric	F4.0		Assumption
SPSTEP	24	Step #	Numeric	I1		Assumption
SPYR	27-30	Year	Numeric	I4		N. Lights
SPRHS	33-39	Firm MW Available	MW	F7.1	UCI$FMW	N. Lights
SPPKRHS	42-48	Peak MW Available	MW	F7.1	UCI$PMW	N. Lights
SPCF	54-57	Capacity Factor	Numeric	F4.1	UCI$CF	N. Lights
SPDOLL	61-66	Fixed Cost	$/Kw	F6.1		N. Lights
SPMILLS	71-75	Variable Cost	Mills/Kwh	F5.2	UCI$CST	N. Lights

After line 260 additional Canadian build information:

TPRJNAME	1-23	Project name	Alpha	A22
TPROV	24-35	Seller	Alpha	A11
TSUMCAP	36-43	Sum of capacity	Numeric	F6.0
TLEAD	50-51	Lead years	Numeric	I2
TMODYR	56-60	Model start date	Numeric	I4
TPRJYR	66-70	Project start date	Numeric	I4
TCFC	75-80	Capacity factor	Numeric	F5.3
TDMW	84-90	Cost per MW	Numeric	F6.0
TDMWH	92-100	Cost per MWH	Numeric	F8.3
TFOR	105-110	For	Numeric	F5.3
TNUMRGS	119-120	# US regions affected	Numeric	I1
TRGN	121-150	Regions affected (5)	Numeric	5(7X,I2)

Notes: Northern Lights: U.S. Department of Energy, Northern Lights: The Economic and Practical Potential of Imported Power from Canada (DOE/PE-0079)

TABLE A1-2c: PRETTIN File Description (prepett.f Main Pre-Processor Input File**)**
This file contains region to region constraints for every seasonal period. The **prepett.f** pre-processor reads in the file, subtracts out firm power commitments from the constraints, and outputs the result in the ETTIN file.

Variable Name	Columns	Description	Units	Format	Source
IRGEX	1-2	Export Region	Numeric	I2	Assumption
IRGIM	5-5	Import Region	Numeric	I2	Assumption
PTHRESH1	9-13	Price Thresholds	Numeric	F5.3	OE-411

PTHRESH2	15-21	Price Thresholds	Numeric	F5.3	OE-411
IYR	25-26	Year	Numeric	I1	Assumption
CNSTRNTS		Constraint by seasonal period	Numeric	6F7.3	OE-411

Notes: OE-411: DOE Form OE-411, "Coordinated Bulk Power Supply Program Report".

TABLE A1-2d: ETCNCT File Description (prepett.f Main Pre-Processor Input File**)**
This file contains records for firm power contracts between NEMS regions, between NEMS regions and Canada, and between NEMS regions and Mexico.

Variable Name[1]	Columns	Description	Units	Format	Comments	Source
	5-11	Buyer Utility Name	Alpha	A6		OE-411
	17-21	Buyer Utility Code	Numeric	I5		F860
	23-24	Buyer State	Alpha	A2		OE-411
TEMPI	32-35	Buyer Region	Alpha	A4		OE-411
	41-45	Seller Utility Name	Alpha	A5		OE-411
	53-57	Seller Utility Code	Numeric	I5		OE-411
	59-60	Seller State	Alpha	A2		OE-411
TEMPE	68-73	Seller Region	Alpha	A6		OE-411
MW	77-84	Capacity	MW	F8.0		OE-411
S	86	Season	Alpha	A1	'S' = Summer 'W' = Winter	OE-411
SYR	99-02	Start Year	Numeric	F4.0		OE-411
EYR	08-11	End Year	Numeric	F4.0		
	13-20	Record Type	Alpha	A8	'S'= Sales 'P'=Purchase 'R'= Revised Record 'Adj' =Adjustment Rcd.	OE-411
	22-35	Source	Alpha	A14	Pub Name	

[1] Note, there are only variable names listed for those variables which are input from the file.

Notes: OE-411: DOE Form OE-411, "Coordinated Bulk Power Supply Program Report".
F860 - "Annual Electric Generator Report"
NEMS use = Input to ETT Pre-Processor Program

TABLE A1-3: ETTDEM File Description
This file contains the international transmission demand data. The pre-processor **prepett.f** reads information from the files stated above and compiles the information into this direct access file (DAF), a computer only readable format. For a description of the list of variables used in the model see the common **dispett** Table A2-8.

TABLE A1-4: ECPDAT File Description
This file contains initial input data from the file ECPDAT for the LP model that are not modified throughout the model. It primarily consists of character variables that are used to generate row and column names and index arrays, switch arrays and array maximums. This file is self-contained with its own documentation. Records are read in using the subroutine RD$TBL to read the data from external flat files and store into the common block **ecpcntl**. For a description of the variables please see Table A2-3.

TABLE A1-5: ELDATYR File Description

This file contains historic data to overwrite EMM output in certain reports and nuclear maximum capacity factors and annual costs. Records are read in unformatted with a space between each data item. The variables are read in and stored in the common **dispinyr** Table A2-9. The Comments section in the description of **dispinyr** indicates the corresponding read where applicable.

TABLE A1-6: SO2CNTL File Description

This file contains the number of SO2 compliance groups, the initial SO2 penalty costs, and additional allowances for each compliance group. There is one Type 1 record per year. The UNSO2 variable indicates the number of Type 2 records which follow it. Records are read in unformatted with a space between each data item.

Record Type	Field	Units	Variable	Comments	Source
1	Record Type Label	Alpha	DUMMY	'#SO2,ALLOW'	Assumption
1	# of Compliance Groups	Numeric	UNSO2		Assumption
1	Total SO_2 Produced		UTLSO2		EFD output
1	Quantity Tolerance		UTLSO2I		Assumption
1	Price Tolerance		UTPSO2		Assumption
1	Maximum Price Jumps		UTJUMP		Assumption
2	Record Type Label	Alpha	DUMMY	'INITIAL PSO2'	Assumption
2	Initial SO2 Penalty Cost	$/ton	UPNSO2(GRP)		Assumption
2	Additional Allowances	tons	UIALLW(GRP)	EFD Output	

Notes: GRP subscript values = 1 through most recently read UNSO2

TABLE A1-7: NUGPIPE File Description

Historical nonutility information is contained in this file. The NUGPIPE file is input to the EFD and read in in the RDNUGS subroutine in the **unugs.f** code. This file contains named variables and more are read in than are used. Records are read in unformatted with a space between each data item The variables described below are only those actually used by the code.

Variable Name	Description	Units	Source
LINELOSS	Line Loss Factor	percent	Memo
CGCOMPF	Comm. Cogen. Fix. Cost	$/kw	Assumption
CGINDPF	Ind. Cogen Fix. Cost	$/kw	Assumption
NOTRD	Regional Trade Restriction Switches	numeric	
NOPLT	Plant Type Trade Restriction Switches	numeric	
DISPLAC	Allowable Displacement Values by Reg	numeric	
ECANSQZ	Canadian GW reductions by region by yr	percent	
EXPCI	Canadian Interruptible Exports	numeric	Exogeneous

Notes: Memo -Memorandum from Less Goudarzi and Joanne Shore, OnLocation Inc., to Pat Toner "Deliverable 6, Draft Data Inputs for Implementation of ETT, Task 92086, Contract DE-AC01-88EI21033", March 5, 1993.

TABLE A1-8: COGENMF File Description

This file contains initialization data for 4 of the cogeneration variables (CGCOMGEN, CGINDGEN, CGREGEN, GRIDSHR) used in the model. Records are read in unformatted with a space between each data item. The variables are read in as zero and stored in the common **cogen** for further use during a model run. For a description of the variables please see the common **cogen** Table A2-12.

TABLE A1-9: GEODATA File Description

This file contains geothermal and biomass plant data that is read in and stored in the common **emmgeo**. The information is mainly used in the **prepplt.f** preprocessor. For a description of the variables see the common **emmgeo** Table A2-13.

A.2 Common Blocks

TABLE A2-1: emmparm Common Block Description

Field	Units	Variable	Value	Source
Max. Number of Vertical Slices	Numeric	EFD$MVS	60	Assumption
Max number of steps per group (EFD)	Numeric	EFD$SSZ	6	Assumption
Number of load groups per season (EFD)	Numeric	EFD$STP	3	Assumption
Number of Seasonal Periods	Numeric	EFD$MSP	6	Assumption
Number of Renewable Types	Numeric	EFD$RNW	9	Assumption
# of Dispatchable Capacity Types	Numeric	EFD$DSP	17	Assumption
Number of ECP Fuels per Plant	Numeric	EFD$FPP	5	Assumption
Number of Plant Groups	Numeric	EFD$MPG	1000	Assumption
Max number of boiler bottom types	Numeric	EFD$BTM	3	Assumption
Number of international provinces	Numeric	EFD$PROV	8	Assumption
Max number of NOX control technologies	Numeric	EFD$NCT	16	Assumption
Maximum Number of Trade Groups	Numeric	EFD$MTG	30	Assumption
Max Records in Constraints File	Numeric	EFD$RECS	200	Assumption
Number of Renewable Groups	Numeric	EFD$MHG	600	Assumption
Number of Horizontal Slices	Numeric	EFD$MHS	EFD$MPG	Assumption
Number of SO2 Compliance Groups	Numeric	EFD$SO2	2	Assumption
Number of Boiler Types	Numeric	EFD$BTP	13	Assumption
Supply/Reporting Regions per Fuel	Numeric	EFD$FRG	3	Assumption
Compliance Groups per Plant Group	Numeric	EFD$CGP	1	Assumption
Ownership Type	Numeric	EFD$OWN	5	Assumption
Number of Fuel Types	Numeric	EFD$NFL	20	Assumption
Number of Building Blocks/Season	Numeric	EFD$LDG	6	Assumption
Total Plant types DSP and RNW	Numeric	EFD$CAP	24	Assumption
Max # Regions for any Fuel Type	Numeric	EFD$MFRG	24	Assumption
Vintage(1=Existing,2=Pipeline,3=New)	Numeric	EFD$VIN	3	Assumption
Season/Time of Day Groups	Numeric	ELD$DAY	18	Assumption
Segments in each Ssn/Time of Day Grp	Numeric	ELD$HRS	64	Assumption
ECP Number of Load Groups	Numeric	ECP$STP	9	Assumption
ECP number of intermittent capy types	Numeric	ECP$I_R		Assumption
ECP Max Steps per Group	Numeric	ECP$SSZ	5	Assumption
ECP Seasons Periods	Numeric	ECP$MSP	3	Assumption
ECP # Building Blocks/Season	Numeric	ECP$LDG	6	Assumption
ECP Number of Vertical Load Slices	Numeric	ECP$VLS	22	Assumption
Length of Explicit Planning Horizon	Numeric	ECP$XPH	6	Assumption
Length of Full Planning Horizon	Numeric	ECP$FPH	30	Assumption
ECP # of Dispatchable Capacity Types	Numeric	ECP$DSP	18	Assumption
ECP # of Intermittent Capacity Types	Numeric	ECP$INT	3	Assumption
ECP # of Other Renew. Capacity Types	Numeric	ECP$RNW	5	Assumption
ECP # of DSM Program Types	Numeric	ECP$DSM	12	Assumption
ECP Length DSM Investment Profile	Numeric	ECP$LINV	10	Assumption
ECP # of Clusters-Retrofit Candidates	Numeric	ECP$SCR	1	Assumption
ECP # of Plant Groups/Retrofit Group	Numeric	ECP$SGP	130	Assumption
ECP # of Fuel Types	Numeric	ECP$NFL	20	Assumption
ECP # Fuels per Plant	Numeric	ECP$FPP	4	Assumption
ECP Longest Construction Profile	Numeric	ECP$LCP	10	Assumption
ECP Total Plant DSP, INT, and RNW	Numeric	ECP$CAP	24	Assumption
Ownership Type(1=Util,2=NonUtil)	Numeric	ECP$OWN	2	Assumption
# of Canadian Imp. Spply Crv Steps	Numeric	ECP$CIS	2	Assumption

# Coef for Coal Price Expectations	Numeric	ECP$NCC	5	Assumption
ECP Number of storage capacity types	Numeric	ECP$STO	2	Assumption
ECP Max. # of scrubber type conversions	Numeric	ECP$CSC	3	Assumption
Max number of import/export regions	Numeric	ECP$MXP	3	Assumption
Max numbeer of boiler types per plant type	Numeric	ECP$BTP	3	Assumption
Vintage (1=1990,2=1989...34=1955)	Numeric	EFP$VIN	34	Assumption
Ownership Type (1=Private, 2=Public)	Numeric	EFP$OWN	2	Assumption
Financial Pl Types DSP,INT, and RNW	Numeric	EFP$CAP	12	Assumption
New/Pipeline builds modeled in EFP	Numeric	EFP$BLD	600	Assumption
Max number of trade groups	Numeric	ETT$MTG	150	Assumption
Max number of Can. Trade groups	Numeric	ETT$CAN	30	Assumption
Max number of boiler types includes bottom type		EMM$BTP	30	Assumption
"	Numeric	EMM$NCT	20	Assumption
Number fuel types for emission calculations	Numeric	EMS$NFL	6	Assumption
Max Number of Plant Records	Numeric	WPLT$REC	25000	Assumption
Max Number of Plant Regions	Numeric	WPLT$RGN	20	Assumption
Max Number of Groups per Region	Numeric	WPLT$GRP	2000	Assumption
Max # boiler/bottom/nox red. Combo per plant record		WPLT$BBN	6	Assumption

DEFINITIONS

EFD$MVS - 60 vertical slices (max), based on seasons and time

EFD$MSP - Seasonal Periods

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

EFD$RNW - Number of Renewable Types

1 Conventional Hydroelectric
2 Hydro Pipeline
3 Hydro Reversible
4 Geothermal
5 Municipal Solid Waste
6 Wood/Biomass
7 Solar
8 Wind

EFD$DSP - Dispatchable Plant Type

1 Existing Unscrubbed Coal Steam pre-1965
2 Existing Unscrubbed Coal Steam post-1965
3 Existing Scrubbed Coal Steam
4 Retrofitted Coal
5 New Coal
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 BW
16 Nuclear PW

EFD$FPP = Number of Fuels Per Plant

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

ETT$RECS - Maximum Number of Constraints in File

EFD$MHS - Number of Horizontal Slices

EFD$SO2 - Number of SO2 Compliance Groups

1 = National Compliance
2 = currently not used

EFD$OWN - Ownership Type

1 = Public
2 = Private
3 = Exempt Wholesale Generator

EFD$NFL = Fuel Types

Note: Coal Categories are defined as follows:

Coal Category	SO_2 Emission Level
Low	$0.00 \le SO_2 \le 1.20$
Medium	$1.20 < SO_2 \le 3.34$
High	$SO_2 > 3.34$

1 = OULC = Old (pre-1965) existing Unscrubbed Low Sulfur Coal
2 = OUMC = Old (pre-1965) existing Unscrubbed Medium Sulfur Coal
3 = OUHC = Old (pre-1965) existing Unscrubbed High Sulfur Coal
4 = NULC = New (post-1965) Existing Unscrubbed Low Sulfur Coal
5 = NUMC = New (post-1965) Existing Unscrubbed Medium Sulfur Coal
6 = NUHC = New (post-1965) Existing Unscrubbed High Sulfur Coal
7 = UISC = Scrubbed Coal
8 = UIGF = Natural Gas - Firm
9 = UIGI = Natural Gas - Competitive
10 = UIGC = Natural Gas - Interruptible
11 = UIDS = Distillate Oil
12 = UIRL = Residual Low Sulfur Oil
13 = UIRH = Residual High Sulfur Oil
14 = UIUR = Uranium
15 = UIOT = Other

EFD$CAP = Plant Types - EFD$DSP + EFD$RNW (with EFD$RNW indexing beginning at 17; i.e. there are 24

EFD$CAP types with 1-16 the same as EFD$DSP)

EFD$VIN - Plant Vintage

1 Existing
2 Planned
3 Unplanned

TABLE A2-2: parametr Common Block Description

Field	Units	Variable	Value	Source
Years (1990-2015,2020,2025,2030)	Numeric	MNUMYR	29	Assumption
Census Regions (9 + CA + US)	Numeric	MNUMCR	11	Assumption
PADD Regions (5 + US)	Numeric	MNUMPR	6	Assumption
Oil & Gas (OGSM) Regions	Numeric	MNUMOR	13	Assumption
(6 onshore + 3 offshore + 3 Alaska + US)				
Number of NG Border Crossings	Numeric	MNUMBX	18	Assumption
(Canada-6, Mexico-3, Japan, LNG(MA,MD,GA,LA), Can Tot, Mex Tot, LNG Tot, Total)				
NGTDM Regions	Numeric	MNUMGR	15	Assumption
(9 Census + 3 West + AL + HW + US)				
Coal Export Regions	Numeric	MNUMXR	11	Assumption
Coal Supply Regions (16 + US)	Numeric	MNUMLR	17	Assumption
Coal Demand Regions	Numeric	NDREG	13	Assumption
NEMS Regions (13+ AL + HW + US)	Numeric	MNUMNR	16	Assumption
Mfg: number of SIC's	Numeric	MNSICM	40	Assumption
Non-mfg: number of SIC's	Numeric	MNSICNM	12	Assumption
Oil & Gas Categories	Numeric	MNOGCAT	12	Assumption
(EOR + Convential + Tar Sands + Shale +...+ Syn Gas from Liq&Coal + Other Supplemental Gas)				
(EOR+Conventional+Offshr+AK+US)	Numeric	MNOGCRO	5	Assumption
Coal Types	Numeric	MNCLTYPE	16	Assumption
Grades of Crude Oil	Numeric	MNGRADR	5	Assumption
(3 API gravity + 2 Sulfur)				
Number of DSM Residential Programs	Numeric	MNDSMPRS	10	Assumption
# of DSM Commercial Programs	Numeric	MNDSMPCM	10	Assumption
Air Pollutants	Numeric	MNPOLLUT	8	Assumption
(C, CO, CO2, SOx, NOx, VOC, CH4, PART)				
Number of Manufacturing Types	Numeric	MNFTYPE	46	Assumption
(1 = Nat, 2-8 = Non-Mfg, 9-29 = Mfg)				
Number of Expectation Years	Numeric	MNXYR	66	Assumption
(1990-2015, 2016-2066)				
Number of Fuel Types	Numeric	FLTYPE	6	Assumption
(Oil, Natural Gas, MCL, Scl, Ren, Al)				
Emissions of Ethanol (5 Volume Steps)	Numeric	MNETOH	5	Assumption
Emissions (Corn & Biomass)	Numeric	MNCROP	2	Assumption
Number of Historical SEDS Years	Numeric	MSEDYR	5	Assumption

DEFINITIONS

Note: See the Integrating Module Documentation for a description of the regions used by each module. The following parameter descriptions only gives a listing of the region's names.

MNUMNR = Years (1990-2015, 2020, 2025, 2030)

MNUMCR = Census divisions - Demand Regions

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

PADD Regions

1	=	PADD I
2	=	PADD II
3	=	PADD III
4	=	PADD IV
5	=	PADD V
6	=	PADD VI

MNUMOR - Oil and Gas Regions

1	=	Northeast
2	=	Gulf Cost (excluding South Louisiana)
3	=	South Louisiana
4	=	Midcontinent
5	=	Southwest
6	=	West Coast
7	=	Rocky Mountain
8	=	Pacific
9	=	Gulf of Mexico
10	=	Atlantic
11	=	Onshore North Slope Alaska
12	=	Off Shore North Slop Alaska
13	=	Other Alaska

NDREG - Coal Demand Regions - States included (census region)

1 NE - CN,NH,VT,MA,CT,RI (New England)
2 YP - NY,PA,NJ (Mddle Atlantic)
3 SA - WV,MD,DC,DE,VA,NC,SC (South Atlantic)
4 GF - GA,FL (South Atlantic)
5 OH - OH (East North Central)
6 EN - IN,IL,MI,WI (East North Central)
7 KT - KY,TN (East South Central)
8 AM - AL,MS (East South Central)
9 CW - MN,IA,ND,SD,NE,MO,KS (West North Central)
10 WS - TX,LA,OK,AR (West South Central)
11 MT - MT,WY,CO,UT,ID,NV (Mountain)
12 ZN - AZ,NM (Pacific)
13 PC - AK,HI,WA,OR,CA (Pacific)

MNUMNR - NEMS Electricity Supply Regions

1	=	ECAR - East Central Area Reliability Coordination Agreement
2	=	ERCOT - Electric Reliability Council of Texas
3	=	MAAC - Mid-Atlantic Area Council
4	=	MAIN - Mid-America Interconnected Network
5	=	MAPP - Mid-Continent Area Power Pool
6	=	NPCC/NE - Northeast Power Coordinating Council/New England
7	=	NPCC/NY - Northeast Power Coordinating Council/New York
8	=	SERC/STV - Southeastern Electric Reliability Council/excluding Florida
9	=	SERC/FL - Southeastern Electric Reliability Council/Florida
10	=	SPP - Southwest Power Pool
11	=	WSCC/NWP - Western Systems Coordinating Council/Northwest Power Pool Area
12	=	WSCC/RA - Western Systems Coordinating Council/Rocky Mountain Power Area and Arizona-New Mexico Power Area
13	=	WSCC/CNV - Western Systems Coordinating Council/California-Southern Nevada Power Area
14	=	Alaska
15	=	Hawaii
16	=	National Total

MNPOLLUT - Air Pollutants

1	=	Carbon (C)
2	=	Carbon Monoxide (CO)
3	=	Carbon Dioxide (CO_2)
4	=	Sulfur Dioxide (SO_x)
5	=	Nitrogen Oxide (NO_x)
6	=	Volatile Organic Compounds (VOC)
7	=	Methane (CH4)
8	=	Particulate Matter (PART)

TABLE A2-3: <u>ecpcntl</u> Common Block Description
Contains initial input data from the file ECPDAT for the LP model that are not modified throughout the model. It primarily consists of character variables that are used to generate row and column names and index arrays, switch arrays and array maximums.

Field	Units	Variable Name	Source
Real Capital Cost Deflator	Numeric	UPCAPD(MNUMYR+ECPXPH,ECPCAP)	
Net Tax Rate Numeric	UPTXRT		
NUG Interest Premium	Numeric	UPNIPRM	
NUG Return on equity premium	Numeric	UPNRPRM	
NUG Debt Fraction	Numeric	UPNFDT	
Capacity Credit	Numeric	UPCCR(ECP$CAP)	
Maximum Capacity Factor	Numeric	UPMCF(ECP$CAP)	
Construction Profile	Numeric	UPCPRO(ECPCAP,ECPLCP)	
Capital Cost Credit	Numeric	UPCSB(ECP$CAP)	
Fixed O & M Cost	Numeric	UPFOM(ECP$CAP)	
Forced Outage Rate	Numeric	UPFORT(ECP$CAP)	
Overnight Capital Cost	Numeric	UPOVR(ECP$CAP)	
Planned Maintenance Outage Rate	Numeric	UPPMRT(ECP$CAP)	
Regional Risk Factors	Numeric	UPRSK(ECP$CAP)	
Variable O & M Cost	Numeric	UPVOM(ECP$CAP)	
O & M Cost Credit	Numeric	UPVSB(ECP$CAP)	

Current Heat Rate	Numeric	UPHTRT(ECP$CAP)
Add on transmission cost	Numeric	UPCTRM(ECP$CAP)
Calendar Yr Of 1st Comm Operation	Numeric	UPAVLYR(ECP$CAP)
Construction Leadtime (Years)	Numeric	UPCLYR(ECP$CAP)
Economic Life (Years)	Numeric	UPECLF(ECP$CAP)
NUG Contract Life (Years)	Numeric	UPNCLF(ECP$CAP)
NUG Loan Life (Years)	Numeric	UPNLLF(ECP$CAP)
Tax Life (Years)	Numeric	UPTXLF(ECP$CAP)
Utility Contract Life (Years)	Numeric	UPUCLF(ECP$CAP)
Minimum/Maximum Capacity Factor	Numeric	UPPCFB(ECP$DSP,2)
Scrubber Efficiency	Numeric	UPPSEF(ECP$DSP)
SO2 Scrubber Emissions Rate	Numeric	UPPSRT(ECP$DSP)
Initial Heat Rate	Numeric	UPPHRT0(ECP$DSP)
Final Heat Rate	Numeric	UPPHRTN(ECP$DSP)
Boiler Type Share	Numeric	ECP_PCT(ECPBTP,ECPCAP)
Number of Boiler Types Per Plant Type	Numeric	ECP_BBN(ECP$CAP)
Fire Type Code	Numeric	ECP_FTP(ECPBTP,ECPCAP)
NOX Control Type Code	Numeric	ECP_NCT(ECPBTP,ECPCAP)
Bottom Type Code	Numeric	ECP_BTM(ECPBTP,ECPCAP)
Intermittent capacity credit scaling factor	Numeric	UPICCF(ECP$INT)
Generation Subsidies (mills/kwh)	Numeric	UPIGSUB(ECP$INT)
Start year of generation subsidies	Numeric	UPIGSY1(ECP$INT)
Last year of generation subsidies	Numeric	UPIGSYL(ECP$INT)
# years from online year that generation subsidies affect		UPIGSYR(ECP$INT)
ECP Fuel Types	Numeric	UPFLTP(ECPDSP,ECPFPP)
CONS. PROFILE--RETROFITS	Numeric	UPSCPR(ECP$LCP)
HEAT RATE PEN. (%)-RETROFIT	Numeric	UPSHPEN(ECPDSP,ECPSCR)
CAPACITY PEN. (%)-RETROFIT	Numeric	UPSCPEN(ECPDSP,ECPSCR)
CONS. PROFILE--RETROFITS	Numeric	UPSCPR(ECP$LCP)
HEAT RATE PEN. (%)-RETROFIT	Numeric	UPSHPEN(ECPDSP,ECPSCR)
CAPACITY PEN. (%)-RETROFIT	Numeric	UPSCPEN(ECPDSP,ECPSCR)
RISK PREMIUM--RETROFIT	Numeric	UPSRSK
ECONOMIC LIFE--SCRUBBER RETRO	Numeric	UPSELF .
CONSTRUCTION LEADTIME--RETRO	Numeric	UPSCLT .
ECP CAPY TYPE CONVERTED TO	Numeric	UPSCR2(ECP$DSP)
SCRUBBER CAPY TYPE CONVERT	Numeric	UPSCSCR(ECPDSP,ECPCSC)
PLANTS SCRUBBED FROM	Numeric	UPSCRFRM(ECPDSP,ECPCSC)
Max value for ECP tech (<=ECP$CAP)	Numeric	ECPCAPM
Max val ECP DSP tech (<=ECP$CAP)	Numeric	ECPDSPM
Max val for ECP INT tech (<=ECP$INT)Numeric		ECPINTM
Max val for ECP I_R tech (<=ECP$I_R)	Numeric	ECPI_RM
Max val ECP RNW tech (<=ECP$RNW)	Numeric	ECPRNWM
Max val ECP STO tech (<=ECP$STO)	Numeric	ECPSTOM
REVISE DERATES - 0=NO,Y=YES	Numeric	ECP$DRTE
INCLUDE DSM - 0=NO,1=YES	Numeric	ECP$IDSM
CAP COST LRN/OPT - 0=NO,1=YES	Numeric	ECP$LFCC
HTRATE LRNING - 0=NO,1=YES	Numeric	ECP$LFHR
INCLUDE MKT/SHR - 0=NO,1=YES	Numeric	ECP$MSHR
USE RISK PREM. - 0=NO,1=YES	Numeric	ECP$RSK
Ambient conditions mult.- 0=NO,1=YES	Numeric	ECP$AMB
Map of DSP to CAP technology indices	Numeric	UCPDSPI(ECP$DSP)
Map of INT to CAP technology indices	Numeric	UCPINTI(ECP$INT)
Map of RNW to CAP technology indices	Numeric	UCPRNWI(ECP$RNW)
Map of STO to CAP technology indices	Numeric	UCPSTOI(ECP$STO)
Map of INT to I_R technology indices	Numeric	UIRINTI(ECP$INT)
Map of RNW to I_R technology ind	Numeric	UIRRNWI(ECP$RNW)

CENSUS REGION BY PLANT TYPE	Numeric	UPCENSUS(ECP$CAP,MNUMNR)	
CANADIAN IMPORTS RG 0=N 1=Y	Numeric	UPCIMP(MNUMNR)	
COAL REGION	Numeric	UPCLRG(MNUMNR)	
IRT BLD SW 0=NOT 1=ALLOWED	Numeric	UPETTSW(ECP$CAP)	
REGIONAL TRNSFERS 0=N 1=Y	Numeric	UPGTRN(MNUMNR)	
RENEW PLT TYPE INDEX	Numeric	UPLNTIDX(ECP$I_R)	
ALLOW DSP IN MKT/SHR--0=N,1=Y	Numeric	UPMSHSW(ECP$CAP)	
NATURAL GAS REGION	Numeric	UPNGRG(MNUMNR)	
NUG BLD SW 0=NOT 1=ALLOWED	Numeric	UPNUGSW(ECP$CAP)	
OPERATE TYPE SWITCH	Numeric	UPTOPR(ECP$CAP)	
CAP TRNSFERS 0=NOT 1=ALLOWED	Numeric	UPCPTRSW(ECP$CAP)	
PLANT TYPE	Numeric	UPTTYP(ECP$CAP)	
EXPORT TO IMPORT REGION MAP	Numeric	UPXRGN(MNUMNR,MNUMNR)	
Mask of DSP to CAP technology indices	Numeric	UCPDSPS(ECP$CAP)	
Mask of INT to CAP technology indices	Numeric	UCPINTS(ECP$CAP)	
Mask of RNW to CAP technology indices	Numeric	UCPRNWS(ECP$CAP)	
Mask of STO to CAP technology indices	Numeric	UCPSTOS(ECP$CAP)	
Mask of ECP Plant Types Included	Numeric	UPLTSW(ECP$CAP)	
Mask of INT to I_R technology indices	Numeric	UIRINTS(ECP$I_R)	
Mask of RNW to I_R technology indices	Numeric	UIRRNWS(ECP$I_R)	
ECP Technology Long Name	Numeric	UPLNAME(ECP$CAP)	
ECP Technology Name For Reports	Numeric	UPNAME(ECP$CAP,3)	
PLANT CODES	Numeric	UPLNTCD(ECP$CAP)	
GNP Def.'s	Numeric	UPGNPD(MNUMYR+ECP$XPH)	
Target Cov Ratio-Pur. Constraint	Numeric	UPTCRT	
Length of Full Planning Horizon	Numeric	UNFPH	
Length of Expl. Planning Horizon	Numeric	UNXPH	
Vint. Type -(0=Ex.,1=New)- ECP Cap	Numeric	UPVTYP(ECP$CAP)	
Financial Type	Numeric	UPFTYP(ECP$CAP)	
Print Mode (0=No MPS Recs,1=Print MPS recs)	Numeric	ECP$PRNT	
Revise Mode (0=Replace Ex. Mtx.,1=Revise Ex. Mtx.)	Numeric	ECP$MODE	
EFD to ECP Fuel Mapping	Numeric	UFL$ECP(ECP$NFL,ECP$FPP)	
Initialize Matrix (1=Yes, 0=No)	Numeric	ECP$INIT	
EFP Type Retrofit (=13)	Numeric	EFP$SCR	
EFP Type Transmission (=14)	Numeric	EFP$TRN	
Yr to Write ACT File(0=Write 1st Yr)	Numeric	ECPACT	
Basis Mode (0=From Previous Yr,1=From Input File)	Numeric	ECPBASIS	
MPS Format Input File Name & Path	Alpha	ECP$FILE	
EMM Basis File Name	Alpha	ECP$FILEB	
Objective Function Name	Alpha	UPOBJ	
Right Hand Side Name	Alpha	UPRHS	
Bound Row Name	Alpha	UPBND	
Database Name	Alpha	ECP$DBNM	
Problem Name	Alpha	ECP$PROB	
Deck Name	Alpha	ECP$DECK	
Basis File Deck Name	Alpha	ECP$DECKB(YR)	
F860 Primary Fuel Code	Char	UPF860(ECP$CAP)	F860
F860 Secondary Fuel Code	Char	USF860(ECP$CAP)	F860
DSM Group Codes	Char	UPDMCD(ECP$DSM)	Assumption
Fuel Codes	Char	UPFLCD(ECP$NFL)	Assumption
F860 Prime Mover Code	Char	UPM860(ECP$CAP)	F860
EFP Type	Char	UPEFPT(ECP$CAP)	Assumption
Fin Ownership Type (1='U',2='N')	Char	UPOWNCD(ECP$OWN)	

Load Segment Codes	Char	UPLDCD(ECP$VLS)	Assumption
Mode of Operation Codes	Char	UPMDCD(ECP$VLS)	Assumption
Region Codes	Char	UPRGCD(ECP$RGN)	Assumption
Year Codes	Char	UPYRCD(ECP$FPH)	Assumption
Retrofit Cluster Code	Char	UPSCCD(ECP$CSR)	Assumption
F759 Prime Mover Code	Char	UPM759(ECP$CAP)	F759
F759 Primary Fuel Code	Char	UPF759(ECP$CAP)	F759
F759 Secondary Fuel Code	Char	USF759(ECP$CAP)	F759

Notes: F860: Form EIA-860, "Annual Electric Generator Report".
F759: Form EIA-759, "Monthly Power Plant Report".

TABLE A2-4: ncntrl Common Block Description

Variable	Description	Indices	Units	Source
EXW	Execute World (international)		Numeric	
EXM	Execute Mac (Macroeconomic)		Numeric	
EXR	Execute Resd (Residential)		Numeric	
EXK	Execute Comm (Commercial)		Numeric	
EXI	Execute Ind (Industrial)		Numeric	
EXT	Execute Tran (Transportation)		Numeric	
EXE	Execute Util (Utility)		Numeric	Assumption
EXC	Execute Coal (Coal Supply)		Numeric	
EXL	Execute Well (Oil and Gas Supply)		Numeric	
EXG	Execute Pipe (Gas Trans & Distr)		Numeric	
EXO	Execute Refine (Petroleum Refinery)		Numeric	
EXN	Execute Renew (Renewables)		Numeric	
RUNMOD	Flags (Is each model being run?)		Numeric	
PRTDBGW	Print Debug in World (International)		Numeric	
PRTDBGM	Print Debug in Mac (Macroeconomic)	Numeric		
PRTDBGR	Print Debug in Resd(Residential)		Numeric	
PRTDBGK	Print Debug in Comm (Commercial)		Numeric	
PRTDBGI	Print Debug in Ind (Industrial)		Numeric	
PRTDBGT	Print Debug in Tran (Transportation)		Numeric	
PRTDBGE	Print Debug in Util		Numeric	Assumption
PRTDBGC	Print Debug in Coal(Coal Supply)		Numeric	
PRTDBGL	Print Debug in Oil and Gas Supply		Numeric	
PRTDBGG	Print Debug in Gas Trans & Distr		Numeric	
PRTDBGO	Print Debug in Refine(Petroleum Ref)		Numeric	
PRTDBGN	Print Debug in Renew (Renewables)		Numeric	
FIRSYR	First Forecast Year Index		Numeric	Assumption
LASTYR	Last Forecast Year Index		Numeric	Assumption
MAXITR	Maximum Iterations		Numeric	Assumption
FRCTOL	Min Fractional Conver Tol		Numeric	Assumption
ABSTOL	Minimum Absolute Convergence Tol		Numeric	Assumption
RLXPC	Relaxation Percentage		Numeric	
NYRS	Number of Growth Years		Numeric	
I4SITE	Foresight Option		Numeric	
I4SCNT Foresight Control		Numeric		
IRELAX	Option to run Heuristic Routine		Numeric	
WWOP	World Oil Price Case		Numeric	Assumption
MMAC	Macro Case		Numeric	Assumption

HISTORY	1990 History Data Flag		Numeric	Assumption
MACFDBK	Macroeconomic Feedback Lever		Numeric	
ELASSW	Elasticity Switch		Numeric	
DSMSWTCH	DSM Switch		Numeric	
DBDUMP			Numeric	
MODELON			Numeric	
ECPSTART	Start Year for ECP Module		Numeric	
CURITR	Current Iteration		Numeric	Assumption
CURIYR	Current Year Index		Numeric	Assumption
BASEYR	Yr Corresponding to FIRSYR		Numeric	Assumption
ENDYR	Yr Corresponding to LASTYR		Numeric	Assumption
LOOPOP	NEMS Year Looping		Numeric	Assumption
CTEST	Overall Convergence Test		Numeric	Assumption
FCRL	Final Converg/Reporting Loop Sw		Numeric	
NCRL	Reporting Loop Switch		Numeric	Assumption
CNVTST	Conver Flags for each Model	NMODEL	Numeric	
NMUMYR	Year		Numeric	Assumption
ITIMNG	Timing Switch		Numeric	
YEARPR	For Reporting, Year Dollars		Numeric	
MORDER	Holds Execution Order of Modules		Numeric	
SCALPR	For Reporting, Deflator, Yearpr $		Numeric	
SCEN	Scenario		Alpha	Assumption
DATE	Date Code		Alpha	Assumption
COMMENT	Comment Line frm Job Stream		Alpha	Assumption
SUBR_NAMES	Short Subroutine Names	NMODEL	Alpha	
SUBR_DESCR	Long Subroutine Names	NMODEL	Alpha	
SUBR_VERS	Subroutine Version Used	MODEL+2	Alpha	
FORE_SITE_CNTL	Description for I4SCNT	2	Alpha	
FORE_SITE_TYPE	Description for I4SITE	3	Alpha	
LOOP	Description for LOOPOP	2	Alpha	

Table A2-5: <u>coalemm</u> Common Block Description
Flow of Data between EMM and the Coal Module

Variable	Indices	Description
Coal Demand at Coal Demand Regions by Plant Type and SO2 Standards (Trillions of Btu)		
QCLOLNR	(NDRGG,MNUMYR)	Demand for Coal at Old Units Low Emission Standards
QCLOMNR	(NDRGG,MNUMYR)	Demand for Coal at Old Units Medium Emission Standards
QCLOHNR	(NDRGG,MNUMYR)	Demand for Coal at Old Units High Emission Standards
QCLNLNR	(NDRGG,MNUMYR)	Demand for Coal at New Units Low Emission Standards
QCLNMNR	(NDRGG,MNUMYR)	Demand for Coal at New Units Medium Emission Standards
QCLNHNR	(NDRGG,MNUMYR)	Demand for Coal at New Units High Emission Standards
QCLSBNR	(NDRGG,MNUMYR)	Demand for Coal at Scrubbed Units
Percent Removal of SO2 at Coal Demand Regions by Plant Type and SO2 Standards		
RCLOLNR	(NDRGG,MNUMYR)	Percent Removal of SO2 at Old Units Low Emission Standards
RCLOMNR	(NDRGG,MNUMYR)	Percent Removal of SO2 at Old Units Medium Emission Standards
RCLOHNR	(NDRGG,MNUMYR)	Percent Removal of SO2 at Old Units High Emission Standards
RCLNLNR	(NDRGG,MNUMYR)	Percent Removal of SO2 at New Units Low Emission Standards
RCLNMNR	(NDRGG,MNUMYR)	Percent Removal of SO2 at New Units Medium Emission Standards
RCLNHNR	(NDRGG,MNUMYR)	Percent Removal of SO2 at New Units High Emission Standards
RCLSBNR	(NDRGG,MNUMYR)	Percent Removal of SO2 at Scrubbed Units

SO2 Info

SO2BANK	(MNUMYR)	SO2 Banking (Millions of Tons of SO2)
	(Net Impact - => Smaller Allowances + => Larger Allowances)	
SO2OTHER	(MNUMYR)	SO2 Emissions from Non-Coal Generators (Millions of Tons SO2)
SO2COST	(MNUMYR)	SO2 Penalty Cost ($/Ton)

Expected Coal Capacity by Plant Type and SO2 Standard (Current Year Plus Projected Years) (GW)

GCLOLNR	(NCLEXP,NDRGG,MNUMYR)	Gigawatts of Old Units Low Emission Standards
GCLOMNR	(NCLEXP,NDRGG,MNUMYR)	Gigawatts of Old Units Medium Emission Standards
GCLOHNR	(NCLEXP,NDRGG,MNUMYR)	Gigawatts of Old Units High Emission Standards
GCLNLNR	(NCLEXP,NDRGG,MNUMYR)	Gigawatts of New Units Low Emission Standards
GCLNMNR	(NCLEXP,NDRGG,MNUMYR)	Gigawatts of New Units Medium Emission Standards
GCLNHNR	(NCLEXP,NDRGG,MNUMYR)	Gigawatts of New Units High Emission Standards
GCLSBNR	(NCLEXP,NDRGG,MNUMYR)	Gigawatts of Scrubbed Units

Quantity of Coal by Plant Type, SO2 Standards and Rank (Trillions of Btu)

QBCOLNR	(NDRGG,MNUMYR)	Bituminous Demand to Old Units Low Emission Standards
QSCOLNR	(NDRGG,MNUMYR)	Subbituminous Demand to Old Units Low Emission Standards
QLCOLNR	(NDRGG,MNUMYR)	Lignite Demand to Old Units Low Emission Standards
QBCOMNR	(NDRGG,MNUMYR)	Bituminous Demand to Old Units Medium Emission Standards
QSCOMNR	(NDRGG,MNUMYR)	Subbituminous Demand to Old Units Medium Emission Standards
QLCOMNR	(NDRGG,MNUMYR)	Lignite Demand to Old Units Medium Emission Standards
QBCOHNR	(NDRGG,MNUMYR)	Bituminous Demand to Old Units High Emission Standards
QSCOHNR	(NDRGG,MNUMYR)	Subbituminous Demand to Old Units High Emission Standards
QLCOHNR	(NDRGG,MNUMYR)	Lignite Demand to Old Units High Emission Standards
QBCNLNR	(NDRGG,MNUMYR)	Bituminous Demand to New Units Low Emission Standards
QSCNLNR	(NDRGG,MNUMYR)	Subbituminous Demand to New Units Low Emission Standards
QLCNLNR	(NDRGG,MNUMYR)	Lignite Demand to New Units Low Emission Standards
QBCNMNR	(NDRGG,MNUMYR)	Bituminous Demand to New Units Medium Emission Standards
QSCNMNR	(NDRGG,MNUMYR)	Subbituminous Demand to New Units Medium Emission Standards
QLCNMNR	(NDRGG,MNUMYR)	Lignite Demand to New Units Medium Emission Standards
QBCNHNR	(NDRGG,MNUMYR)	Bituminous Demand to New Units High Emission Standards
QSCNHNR	(NDRGG,MNUMYR)	Subbituminous Demand to New Units High Emission Standards
QLCNHNR	(NDRGG,MNUMYR)	Lignite Demand to New Units High Emission Standards
QBCSBNR	(NDRGG,MNUMYR)	Bituminous Demand to Scrubbed Units
QSCSBNR	(NDRGG,MNUMYR)	Subbituminous Demand to Scrubbed Units
QLCSBNR	(NDRGG,MNUMYR)	Lignite Demand to Scrubbed Units

Average SO2 Content of Coal at Coal Demand Regions by Plant Type and SO2 Standards (lbs/MMBtu)

SCLOLNR	(NDRGG,MNUMYR)	Avg SO2 Content of Coal to Old Units Low Emission Standards
SCLOMNR	(NDRGG,MNUMYR)	Avg SO2 Content of Coal to Old Units Med Emission Standards
SCLOHNR	(NDRGG,MNUMYR)	Avg SO2 Content of Coal to Old Units High Emission Standards
SCLNLNR	(NDRGG,MNUMYR)	Avg SO2 Content of Coal to New Units Low Emission Standards
SCLNMNR	(NDRGG,MNUMYR)	Avg SO2 Content of Coal to New Units Med Emission Standards
SCLNHNR	(NDRGG,MNUMYR)	Avg SO2 Content of Coal to New Units High Emission Standards
SCLSBNR	(NDRGG,MNUMYR)	Avg SO2 Content of Coal to Scrubbed Units

Average Carbon Content of Coal at Coal Demand Regions by Plant Type and SO2 Standards (MMTC/QUAD)

CCLOLNR	(NDRGG,MNUMYR)	Avg Carbon Content of Coal to Old Units Low Emission Standards
CCLOMNR	(NDRGG,MNUMYR)	Avg Carbon Content of Coal to Old Units Med Emission Standards
CCLOHNR	(NDRGG,MNUMYR)	Avg Carbon Content of Coal to Old Units High Emission Standards
CCLNLNR	(NDRGG,MNUMYR)	Avg Carbon Content of Coal to New Units Lo Emission Standards
CCLNMNR	(NDRGG,MNUMYR)	Avg Carbon Content of Coal to New Units Med Emission Standard
CCLNHNR	(NDRGG,MNUMYR)	Avg Carbon Content of Coal to New Units Hi Emission Standards
CCLSBNR	(NDRGG,MNUMYR)	Average Carbon Content of Coal to Scrubbed Units

Average Btu Content of Coal at Coal Demand Regions by Plant Type and SO2 Standards (MMBtu/Short Ton)

BCLOLNR	(NDRGG,MNUMYR)	Average Btu Content of Coal to Old Units Low Emission Standards
BCLOMNR	(NDRGG,MNUMYR)	Average Btu Content of Coal to Old Units Med Emission Standards
BCLOHNR	(NDRGG,MNUMYR)	Average Btu Content of Coal to Old Units High Emission Standards
BCLNLNR	(NDRGG,MNUMYR)	Average Btu Content of Coal to New Units Lo Emission Standards
BCLNMNR	(NDRGG,MNUMYR)	Avg Btu Content of Coal to New Units Med Emission Standards
BCLNHNR	(NDRGG,MNUMYR)	Average Btu Content of Coal to New Units Hi Emission Standards
BCLSBNR	(NDRGG,MNUMYR)	Average Btu Content of Coal to Scrubbed Units

Demand for Coal at Coal Demand Regions by Plant Type and SO2 Content (Trillions of Btu)

QLSOMNR	(NDRGG,MNUMYR)	Demand for Low Sulfur Coal at Old Units Med Emission Standards
QMSOMNR	(NDRGG,MNUMYR)	Demand for Med Sulfur Coal at Old Units Med Emission Standards
QLSOHNR	(NDRGG,MNUMYR)	Demand for Low Sulfur Coal at Old Units Hi Emission Standards
QMSOHNR	(NDRGG,MNUMYR)	Demand for Med Sulfur Coal at Old Units Hi Emission Standards
QHSOHNR	(NDRGG,MNUMYR)	Demand for High Sulfur Coal at Old Units Hi Emission Standards
QLSNMNR	(NDRGG,MNUMYR)	Demand for Low Sulf Coal at New Units Med Emission Standards
QMSNMNR	(NDRGG,MNUMYR)	Demand for Med Sulf Coal at New Units Med Emission Standards
QLSNHNR	(NDRGG,MNUMYR)	Demand for Low Sulf Coal at New Units High Emission Standards
QMSNHNR	(NDRGG,MNUMYR)	Demand for Med Sulf Coal at New Units High Emission Standards
QHSNHNR	(NDRGG,MNUMYR)	Demand for High Sulf Coal at New Units High Emission Standards
QLSSBNR	(NDRGG,MNUMYR)	Demand for Low Sulfur Coal at Scrubbed Units
QMSSBNR	(NDRGG,MNUMYR)	Demand for Medium Sulfur Coal at Scrubbed Units
QHSSBNR	(NDRGG,MNUMYR)	Demand for High Sulfur Coal at Scrubbed Units

Average SO2 Content of Coal at Coal Demand Regions by Plant Type and SO2 Content (lbs/MMBtu)

SLSOMNR	(NDRGG,MNUMYR)	Avg SO2 of Low Sulfur Coal to Old Units Med Emission Standards
SMSOMNR	(NDRGG,MNUMYR)	Avg SO2 of Med Sulfur Coal to Old Units Med Emission Standards
SLSOHNR	(NDRGG,MNUMYR)	Avg SO2 of Low Sulfur Coal to Old Units Hi Emission Standards
SMSOHNR	(NDRGG,MNUMYR)	Avg SO2 of Med Sulfur Coal to Old Units Hi Emission Standards
SHSOHNR	(NDRGG,MNUMYR)	Avg SO2 of High Sulfur Coal to Old Units Hi Emission Standards
SLSNMNR	(NDRGG,MNUMYR)	Avg SO2 of Lo Sulfur Coal to New Units Med Emission Standards
SMSNMNR	(NDRGG,MNUMYR)	Avg SO2 Med Sulfur Coal to New Units Med Emission Standards
SLSNHNR	(NDRGG,MNUMYR)	Avg SO2 of Lo Sulfur Coal to New Units High Emission Standards
SMSNHNR	(NDRGG,MNUMYR)	Avg SO2 Med Sulfur Coal to New Units High Emission Standards
SHSNHNR	(NDRGG,MNUMYR)	Avg SO2 of Hi Sulfur Coal to New Units High Emission Standards
SLSSBNR	(NDRGG,MNUMYR)	Average SO2 Content of Low Sulfur Coal to Scrubbed Units
SMSSBNR	(NDRGG,MNUMYR)	Average SO2 Content of Medium Sulfur Coal to Scrubbed Units
SHSSBNR	(NDRGG,MNUMYR)	Average SO2 Content of High Sulfur Coal to Scrubbed Units

Average Btu Content of Coal at Coal Demand Regions by Plant Type and SO2 Content (MMBtu/Short Ton)

BLSOMNR	(NDRGG,MNUMYR)	Avg Btu of Low Sulfur Coal to Old Units Med Emission Standards
BMSOMNR	(NDRGG,MNUMYR)	Avg Btu of Med Sulfur Coal to Old Units Med Emission Standards
BLSOHNR	(NDRGG,MNUMYR)	Avg Btu of Low Sulfur Coal to Old Units High Emission Standards
BMSOHNR	(NDRGG,MNUMYR)	Avg Btu of Med Sulfur Coal to Old Units High Emission Standards
BHSOHNR	(NDRGG,MNUMYR)	Avg Btu of High Sulfur Coal to Old Units High Emission Standards
BLSNMNR	(NDRGG,MNUMYR)	Avg Btu of Low Sulfur Coal to New Units Med Emission Standards
BMSNMNR	(NDRGG,MNUMYR)	Avg Btu of Med Sulfur Coal to New Units Med Emission Standards
BLSNHNR	(NDRGG,MNUMYR)	Avg Btu of Low Sulfur Coal to New Units Hi Emission Standards
BMSNHNR	(NDRGG,MNUMYR)	Avg Btu of Med Sulfur Coal to New Units Hi Emission Standards
BHSNHNR	(NDRGG,MNUMYR)	Avg Btu of High Sulfur Coal to New Units Hi Emission Standards
BLSSBNR	(NDRGG,MNUMYR)	Average Btu Content of Low Sulfur Coal to Scrubbed Units
BMSSBNR	(NDRGG,MNUMYR)	Average Btu Content of Medium Sulfur Coal to Scrubbed Units
BHSSBNR	(NDRGG,MNUMYR)	Average Btu Content of High Sulfur Coal to Scrubbed Units

TABLE A2-6: <u>plntin</u> Common Block Description

This common block contains the unit level data from a combination of the F860, F767, F867, F423, and the F759. The pre-processor **prepplt.f** reads in 2 input files and compiles the information into a direct access computer readable form. This is the corresponding common block of information.

Field	Units	Variable	Values	Source
Percent Sold to Grid	numeric	WGRID		F860/F867
Name Plate Act Owned by Identified Co.	megawatt	WC_NP		F860/F867
Summer Capacity Owned	megawatt	WC_SUM		F860
Winter Capacity Owned	megawatt	WC_WIN		F860
Average Heatrate	btu/kwh	WHRATE		F423
Scrubber Efficiency in Removing SO2	numeric	WSCBEF		F767
Fuel Shares	numeric	W_FSHR(EFD$FPP)		
Monthly Capacity Factors	numeric	WCF_M		F860/F759/Various
Average Capacity Factor	numeric	W_CF		F860/F759/Various
Cost per KW for Retrofit of Scrubber	$/kw	WSCBCST		F767
Asset Value	dollars	WASVL		F412
Book CWIP	dollars	WBCWP		F412
CWIP	dollars	WRCWP		F412
Plant Cost	$/kw	WPCST		F412
On-Line Year (9999 if not specified)	Numeric	W_SYR		F860/F867
On-Line Month (12 if not specified)	Numeric	W_SMO		F860/F867
Retire Year (9999 if not specified)	Numeric	W_RYR		F860/F867
Retire Month (12 if not specified)	Numeric	W_RMO		F860/F867
Scrubber On-Line Year	Numeric	WSCBYR		F767
Scrubber Group	Numeric	WSCBGRP		Assumption
Plant Group	Numeric	W_GRP		Assumption
Plant sub Group	Numeric	W_GRP2		Assumption
Refurbishment Date	Numeric	WRFURB		F860/F867
Plant Vintage	Numeric	WVIN		Assume (See values below)
Two Digit NEMS Plant Type Code	Character	WNEMST		F860/F867
NEMS Region Code for Plant Location	Character	WNOPER		F860/F867
NEMS Region Code for Unit Owner	Character	WNOWN		F860/F867
NEMS Fuel Code	Character	WFL(EFD$FPP)		Assumption
Two Digit Sate Code for Plant Location	Character	WSTATE		F860/F867
Census Region Number	Character	W_CR		F860/F867
Natural Gas Region Number	Character	W_GR		F860/F867
Coal Region Number	Character	W_CLRG		F860/F867
Financial Type Number for EFP	Character	WEFPT		F860/F867
Plant Type Number for ECP	Character	WECPT		F860/F867
Boiler Firing Type Code	Character	W_BTP		F759
Nox Reduction Technology Code	Character	W_NCT		F759
Boiler Bottom Type Code	Numeric	W_BTM		F759
Ownership Type	Numeric	WFOWN		F860/F867(See below)

<u>Values for Plant Vintage</u>

0 = Canceled or Retired
1 = Existing
2 = Planned Additions
3 = Unplanned Additions
4 = Repowering (Before)
5 = Repowering (After)
6 = Planned Retrofit (Before)
7 = Planned Retrofit (After)

<u>Ownership Type</u>

1=Private
2=Public
3=NUG

8 = Unplanned Retrofit (Before)
9 = Unplanned Retrofit (After)

Notes: FPP subscript values = 1 through 4 (ECP fuels per plant)
Each record represents 1 year of data.
F860 - "Annual Electric Generator Report"
F867 - "Annual Nonutility Power Producer Report"
F759 - "Monthly Power Plant Report"
F423 - "Monthly Report of Cost and Quality of Fuels for Electric Plants"
F767 - "Steam-Electric Plan Operation and Design Report"

TABLE A2-7: plntcntl Common Block Description

Field	Units	Variable	Values
VARIABLE O&M	Numeric	WOMR	(EFDCAP,EFDFPP)
FIXED O&M (not used)	Numeric	WFOM	(EFD$CAP)
MAXIMUM CAPACITY FACTOR	Numeric	WMXCP	(EFD$CAP)
PLANNED MAINTENANCE RATE	Numeric	WPMR	(EFD$CAP)
FORCED OUTAGE RATE	Numeric	WFOR	(EFD$CAP)
AVERAGE HEATRATES	Numeric	WGHR	(EFDCAP,EFDFPP)
CAPACITY FAC LOWER BOUND	Numeric	WLOWER	(EFD$CAP)
CAPACITY FAC UPPER BOUND	Numeric	WUPPER	(EFD$CAP)
SO2 FACTOR (not used)	Numeric	WSO2F	(EFD$BTP)
MONTHLY HDRO CAPY FACTORS	Numeric	WHYCF	(12,WPLT$RGN)
NUCLEAR CAPACITY FACTORS	Numeric	WNUCFNR	(MNUMNR,MNUMYR)
MAXIMUM FUEL SHARES	Numeric	WCMFSH	(EFDDSP,EFDFPP,MNUMNR)
Fuel type/capacity type (NOT USED)	Numeric	WFLTP	(EFDCAP,EFDFPP)
EFD CAPACITY TYPE	Numeric	WASTS	(EFD$CAP)
RENEWABLE EFD CAPACITY TYPE	Numeric	WHYTP	(EFD$CAP)
CURRENT RECORD COUNTER	Numeric	WREC_INT	
NEXT RECORD COUNTER	Numeric	WREC_NXT	
NEXT RECORD COUNTER	Numeric	WREC_NXT	
RECORD NUMBER OF NEXT RECORD	Numeric	W_NXT	(WPLT$REC)
OLD PLANT RETIREMENT YEAR	Numeric	WO_RYR	(WPLT$REC)
OLD PLANT RETIREMENT MONTH	Numeric	WO_RMO	(WPLT$REC)
OLD PLANT VINTAGE	Numeric	WO_VIN	(WPLT$REC)
Total Number Of Plant Groups Per Region	Numeric	WNGRPS	(WPLT$RGN)
# Plnt Grps Currently In Pipeline/Plnt Rgn	Numeric	WNPIPE	(WPLT$RGN)
1st Plant Record For Plant Group in Region	Numeric	W_INT	(WPLT$RGN,WPLT$GRP)
If=1, Plant is Dispatchable, If=0, Not	Numeric	WTYPE	(WPLT$RGN,WPLT$GRP)
If=1,combined set of plants If=0,one plant	Numeric	WCOMB	(WPLT$RGN,WPLT$GRP)
Plant Group for new unplanned capacity.	Numeric	WNEWGRP	(WPLTRGN,EFDCAP,EFDOWN,ECPBTP)
Plant Type Names	Character	WNAME	(EFD$CAP)
EFD Fuel Types for new unplanned capy	Character	WCFLTP	(EFDCAP,EFDFPP)
Bytes left in block	Character	W_LFT	(ELFT$PCTL)
Plant File Control DAF Record block	Character	WPCNTL	(EBLK$PCTL)

Table A2-8: dispett Common Block Description

Description	Variable	Indices	Units	Source
Net Interregional Electricity Flows	UEITAJ	(EFD$MSP,MNUMNR)	GW	PreProcessor
Canadian Build Decision	UCANBLD	(MNUMNR)	GW	ECP Output

T&D Loss Factor	UQTDLS	(MNUMNR)	Numeric	Assumption
SUMMER CAPABILITY(ex. 500.5)	UCI$CAP	(ECP$CS2)	Numeric	
$/MWH in 1990 $ (ex. 35.75)	UCI$MWH	(ECP$CS2)	Numeric	
$/MW in 1990 $ (ex. 2500.0)	UCI$DMW	(ECP$CS2)	Numeric	
CAP FACTOR (ex. 0.653)	UCI$CFC	(ECP$CS2)	Numeric	
FORCED OUTAGE (ex. 0.055)	UCI$FOR	(ECP$CS2)	Numeric	
NO. REGIONS TIED TO (ex. 3)	UCI$RGN	(ECP$CS2)	Numeric	
REGIONS TIED TO (ex. (1,1)=5 (1,2)=6 (1,3)=7 (1,4)=0 (1,5)=0	UCI$RGS	(ECP$CS2,ECP$CS3)	Numeric	
	AREATR	(EFDMSP,ETTMTG,EFD$MVS)		
	AREATI	(EFDMSP,ETTMTG,EFD$MVS)		
	CAPTR	(EFDMSP,ETTMTG,EFD$MVS)		
	CAPTRI	(EFDMSP,ETTMTG,EFD$MVS)		
	ETDSPN	(EFD$MSP)	Numeric	
	ETDSPT	(EFDMSP,EFDMPG)		
	UCASTS	(EFD$MPG)	Numeric	
	ETFSHR	(EFDMSP,EFDMPG,EFD$FPP)		
	IMMAP	(EFDMSP,ETTMTG,EFD$MVS)		
	EXMAP	(EFDMSP,ETTMTG,EFD$MVS)		
	UNTCOS	(EFDMSP,EFDMPG)		
	IRGNUM	(MNUMNR)	Numeric	
	ETDBID	(EFD$MPG)	Numeric	
MODEL YEAR (ex. 1995)	MODYR	(ECP$CS2)	Numeric	
PROJECT YEAR (ex. 1995)	PROJYR	(ECP$CS2)	Numeric	
LEAD TIME (ex. 2)	LEAD	(ECP$CS2)	Numeric	
PROJECT NAME	PNAME	(ECP$CS2)	Character	
CANADIAN PROVINCE	PROVINCE	(ECP$CS2)	Character	
Filler (Left Over)Spaces	LEFTV	(ELFT$ET3)	Character	
	ETTTRN	(EBLK$ET3)	Character	
	VHOURS	(EFDMSP,EFDMVS)		
	EXMILLS	(EFDMSP,ETTMTG)		
	EXGW	(EFDMSP,ETTMTG,EFD$MVS)		
	VGRP	(EFDMSP,EFDMVS)		
	VSEG	(EFDMSP,EFDMVS)		
	EXCAPJ	(EFDMSP,ETTMTG)		
	EXCAPK	(EFDMSP,ETTMTG)		
	ADJGW	(EFDMSP,EFDMVS)		
	RNWGW	(EFDMSP,EFDMVS)		
	EFDCPJ	(EFDMSP,EFDMHS)		
	EFDCPK	(EFDMSP,EFDMHS)		
	EFDCST	(EFDMSP,EFDMHS)		
Purch pwr costs-var fuel domestic	FTDMDF	(MNUMNR)	Numeric	
Purch pwr costs-var fuel intntl imp	FTIMPD	(MNUMNR)	Numeric	
Purch pwr costs-var fuel intntl exp	FTEXPD	(MNUMNR)	Numeric	
Purch pwr costs-fixed cap domestic	CTDMDF	(MNUMNR)	Numeric	
Purch pwr costs-fixed cap intntl imp	CTIMPD	(MNUMNR)	Numeric	
Purch pwr costs-fixed cap intntl exp	CTEXPD	(MNUMNR)	Numeric	
Firm power Available (Canadian)	UCI$FMW	(ECP$CIS,MNUMNR)	MW	Northern Lights
Peak power Available (Canadian)	UCI$PMW	(ECP$CIS,MNUMNR)	MW	Northern Lights
EXPORT CAPABILITY	URNCSTEX	(EFD$MSP,MNUMNR)		NERC
IMPORT CAPABILITY	URNCSTIM	(EFD$MSP,MNUMNR)		NERC
Capacity Factor	UCI$CF	(ECP$CIS,MNUMNR)	Numeric	Northern Lights
Variable Cost	UCI$CST	(ECP$CIS,MNUMNR)	Mills/kwh	Northern Lights
Canadian Export Region number	UCI$CRG	(ECP$CIS,MNUMNR)	Numeric	Northern Lights
	EFDGW	(EFDMSP,EFDMHS,EFD$MVS)		
	DSPCPJ	(EFDMSP,ETTMTG)		

	DSPCPK	(EFDMSP,ETTMTG)		
	DSPCST	(EFDMSP,ETTMTG)		
	DSPGW	(EFDMSP,ETTMTG,EFD$MVS)		
	LEFTAM	(ELFT$ET4)	Character	
	ETTEX	(EBLK$ET4)	Character	
	CHOURS	(EFDMSP,EFDMVS)		
	CNMILLS	(EFDMSP,ETTCAN)		
	CNGW	(EFDMSP,ETTCAN,EFD$MVS)		
	CGRP	(EFDMSP,EFDMVS)		
	CSEG	(EFDMSP,EFDMVS)		
	CNCAPJ	(EFDMSP,ETTCAN)		
	CNCAPK	(EFDMSP,ETTCAN)		
Y values-ordered pairs-ETT curve	TTYVAL	(EFD$MVS)	Numeric	
Y values-ordered pairs-ETT curve	TIYVAL	(EFD$MVS)	Numeric	
Area under "original" load curve	AREANT	(EFDMPG,EFDMVS)		
Area under "export" load curve	AREATT	(EFDMPG,EFDMVS)		
Area under "import" load curve	AREAIT	(EFDMPG,EFDMVS)		
	IMAREA	(EFD$MVS)	Numeric	
	EXAREA	(EFD$MVS)	Numeric	
International Interrupt Imports	IMPCI	(MNUMYR,MNUMNR)		
International Interrupt Exports	EXPCI	(MNUMYR,MNUMNR)		
	TELAS	(MNUMYR,MNUMNR)		
	IDONE1		Numeric	
	IDONE2		Numeric	
	ULOSSADJ	(EFD$MSP,MNUMNR)		
	LEFTCN	(ELFT$ET5)	Character	
	ETTCN	(EBLK$ET5)	Character	
	TRIREG	(ETT$MTG*MNUMNR)		
	TRICPI	(ETT$MTG*MNUMNR)		
	TRICPJ	(ETT$MTG*MNUMNR)		
	TRICPK	(ETT$MTG*MNUMNR)		
	TRIJSP	(ETT$MTG*MNUMNR)		
	TRICST	(ETT$MTG*MNUMNR)		
	TREREG	(ETT$MTG*MNUMNR)		
	TRECPI	(ETT$MTG*MNUMNR)		
	TRECPJ	(ETT$MTG*MNUMNR)		
	TRECPK	(ETT$MTG*MNUMNR)		
	TREJSP	(ETT$MTG*MNUMNR)		
	TRECST	(ETT$MTG*MNUMNR)		
	TRFEE	(ETT$MTG*MNUMNR)		
	TRLOSS	(ETT$MTG*MNUMNR)		
	TRMW	(ETT$MTG*MNUMNR)		
	TRHOUR	(ETT$MTG*MNUMNR)		
Firm Power Sales (Net)	ZTDMMF	(MNUMNR)	MWH	ECP Output
Firm Power Sales (Gross)	ZTEXMF	(MNUMNR)	MWH	ECP Output
Firm Power Sales (Net)	ZTDMDF	(MNUMNR)	MM$	ECP Output
Firm Power Sales (Gross)	ZTEXDF	(MNUMNR)	MM$	ECP Output
	LEFTTR	(ELFT$ET6)	Character	
	TRNS	(EBLK$ET6)	Character	
	NMARCST	(MNUMNR+EFD$PROV,EFD$MSP,EFD$MVS,MNUMYR)		
	LEFTMR	(ELFT$ET7)	Character	
Canadian Firm Imports	ZTIMPF	(MNUMNR)	MWH	ECP Output
Canadian Firm Imports	ZTIMPD	(MNUMNR)	MM$	ECP Output
Canadian Firm Exports	ZTEXPD	(MNUMNR)	MM$	ECP Output
Canadian Firm Exports	ZTEXPF	(MNUMNR)	MWH	ECP Output
	MRCS	(EBLK$ET7)	Character	

Notes: Northern Lights - U.S. Department of Energy, Northern Lights: The Economic and Practical Potential of Imported Power from Canada (DOE/PE-0079).
NERC - North American Electric Reliability Council

Table A2-9: <u>dispinyr</u> Common Block Description
Historical data; the Comments section indicates where the data is read from in the ELDATYR file.

Description	Variable	Indices	Comments	Source
COAL GEN BY OWNERSHIP TYPE	HGNCLNR	(2,MNUMNR,NYEAR)	'CLGEN'*	F759/F867
GAS (FIRM) GEN/OWNERSHIP TYPE	HGNNGNR	(2,MNUMNR,NYEAR)	'NGGEN'*	F759/F867
Other gas gen by ownership type/NERC	HGNOGNR	(2,MNUMNR,NYEAR)	'OGGEN'*	F759/F867
DS GEN BY OWNERSHIP TYPE/NERC	HGNOLNR	(2,MNUMNR,NYEAR)	'OLGEN'*	F759/F867
NUC GEN BY OWNER TYPE/NERC	HGNURNR	(2,MNUMNR,NYEAR)	'NUGEN'*	F759/F867
PS GEN BY OWNERSHIP TYPE/NERC	HGNPSNR	(2,MNUMNR,NYEAR)	'PSGEN'*	F759/F867
HYD (NOT PS) GEN/OWNER TYPE	HGNHYNR	(2,MNUMNR,NYEAR)	'HYGEN'*	F759/F867
GEO GEN/OWNERSHIP TYPE	HGNGENR	(2,MNUMNR,NYEAR)	'GEGEN'*	F759/F867
MSW GEN/OWNERSHIP TYPE/NERC	HGNMSNR	(2,MNUMNR,NYEAR)	'MSGEN'*	F759/F867
WIND GEN/OWNERSHIP TYPE/NERC	HGNWDNR	(2,MNUMNR,NYEAR)	'WDGEN'*	F759/F867
Solar Gen by Ownership type/NERC	HGNSONR	(2,MNUMNR,NYEAR)	'SOGEN'*	F759/F867
PhotovoltaicGen by Ownership type/NERC	HGNPVNR	(2,MNUMNR,NYEAR)	'PVGEN'*	F759/F867
Wind Gen by Ownership type/NERC	HGNWNNR	(2,MNUMNR,NYEAR)	'WNGEN'*	F759/F867
OTH GEN BY OWNER TYPE/NERC	HGNOTNR	(2,MNUMNR,NYEAR)	'OTGEN'*	F759/F867
Tot. Gen by Ownership Type/NERC	HGNTLNR	(2,MNUMNR,NYEAR)	F759/F867	
COAL CONS/OWNER TYPE/NERC	HFLCLNR	(2,MNUMNR,NYEAR)	'CLCON'*	F759/F867
GAS CONS/OWNER TYPE/NERC	HFLNGNR	(2,MNUMNR,NYEAR)	'NGCON'*	F759/F867
OIL CONS/ OWNER TYPE/NERC	HFLOLNR	(2,MNUMNR,NYEAR)	'OLCON'*	F759/F867
Coal CONS by OWNER TYPE/CENSUS	HFLCLCR	(MNUMCR,NYEAR)	'COAL-CENSUS REG'	
Gas CONS BY OWNER TYPE/CENSUS	HFLNGCR	(MNUMCR,NYEAR)	'GAS-CENSUS REG'	
Oil CONS BY OWNER TYPE/CENSUS	HFLOLCR	(MNUMCR,NYEAR)	'OIL-CENSUS REG'	
GAS CONS BY GAS REGION	HFLNGGR	(21,NYEAR)	'GAS-GAS'	
COAL CONS BY GAS REGION	HFLCLGR	(21,NYEAR)		
OIL CONS BY OWNER TYPE/GAS	HFLOLGR	(21,NYEAR)	'OIL-GAS'	
NUC CONS BY OWNER TYPE/NERC	HFLURNR	(2,MNUMNR,NYEAR)		
PS CONS BY OWNER TYPE/NERC	HFLPSNR	(2,MNUMNR,NYEAR)		
Hyd(NOT PS) CONS by owner type/NERC	HFLHYNR	(2,MNUMNR,NYEAR)		
OTH. CONS BY OWNER TYPE/NERC	HFLOTNR	(2,MNUMNR,NYEAR)		
TOT CONS BY OWNER TYPE/NERC	HFLTLNR	(2,MNUMNR,NYEAR)		
RESIDENTIAL	HELRSNR	(MNUMNR,NYEAR)	'RSDEM'	F861
COMMERCIAL	HELCMNR	(MNUMNR,NYEAR)	'CMDEM'	F861
INDUSTRIAL	HELINNR	(MNUMNR,NYEAR)	'INDEM'	F861
TRANSPORTATION	HELTRNR	(MNUMNR,NYEAR)	'TRDEM'	F861
OTHER	HELOTNR	(MNUMNR,NYEAR)	'OTDEM'	F861
ALL SECTORS	HELASNR	(MNUMNR,NYEAR)	'ASDEM'	F861
PURCHASES FROM NONUTILITIES	HELNUNR	(MNUMNR,NYEAR)	'NUDEM'	F867
FIRM IMPORTS	HTIMPF	(MNUMNR,NYEAR)	'FIRM IMPORTS'	
ECONOMY IMPORTS	HTIMPE	(MNUMNR,NYEAR)	'ECONOMY IMPORTS'	
FIRM EXPORTS	HTEXPF	(MNUMNR,NYEAR)	'FIRM EXPORTS'	
ECONOMY EXPORTS	HTEXPE	(MNUMNR,NYEAR)	'ECONOMY EXPORTS'	
NON-TRADITIONAL COGENERATION	HCNTGEN	(MNUMNR,NYEAR,10)	'OTHER COGEN'	F867
REFINERY COGENERATION	HCREGEN	(MNUMCR,NYEAR,5,2)	'REFINERY COGEN'	F867
EOR COGENERATION	HCOGGEN	(MNUMCR,NYEAR,4,2)	'EOR COGEN'	F867
INDUSTRIAL COGENERATION	HCINDGEN	(MNUMCR,NYEAR,10,2)	'INDUSTRIAL COGEN'	F867
COMMERCIAL COGENERATION	HCCOMGEN	(MNUMCR,NYEAR,10)	'COMMERCIAL COGEN'	
GAS (C,CO,CO2,SO2,NOX,VOC)	HEMNGTL	(MNPOLLUT,NYEAR)	'EMISSION'	EPA 92

OIL (C,CO,CO2,SO2,NOX,VOC)	HEMOLTL	(MNPOLLUT,NYEAR)	'EMISSION'	EPA 92
COAL (C,CO,CO2,SO2,NOX,VOC)	HEMCLTL	(MNPOLLUT,NYEAR)	'EMISSION'	EPA 92
REN (C,CO,CO2,SO2,NOX,VOC)	HEMOTTL	(MNPOLLUT,NYEAR)	'EMISSION'	EPA 92
SO2 emissions by region	HEMSO2R	(MNUMNR,NYEAR)	'SO2,'	
NOX EMISSIONS BY REGION	HEMNOXR	(MNUMNR,NYEAR)	'NOX,'	
CO2 EMISSIONS BY REGION	HEMCO2R	(MNUMNR,NYEAR)	'CO2'	
Calibration fac. For hist. NOX EM	HNOXFAC	(MNUMNR)		
LAST YEAR FOR HIST. EMIS. DATA	UYR_EMIS			
NUC CAPACITY FACTORS	UNUCFNR	(MNUMNR,MNUMYR)	'NUC CF'	OIAF
NUC FUEL PRICES	UPURELN	(MNUMNR,MNUMYR)	'NUC FLCST'	OIAF
LAST HISTORICAL YEAR	UYR_HIST			
LAST STEO YEAR	UYR_STEO			

Rebasing Data for EFP

VAR. O&M BY OWNERSHIP TYPE	HERTOM	(EFD$OWN,MNUMNR,NHIST)
FUEL COST BY FUEL TYPE	HERFFL	(EFD$NFL,MNUMNR,NHIST)
EWG -- REVENUES FROM UTL	HEWGREV	(MNUMNR,NHIST)
EWG -- FIXED $ COMPONENT	HEWGFIX	(MNUMNR,NHIST)
EWG -- COM COGEN REVS FROM UT	HEWGRCC	(MNUMNR,NHIST)
EWG -- IND. COGEN REVS FROM UT	HEWGRIC	(MNUMNR,NHIST)
EWG -- NUGS/REN. REVS FROM UTL	HEWGRNW	(MNUMNR,NHIST)
DOM. FIRM POWER SALES	HETDMMF	(MNUMNR,NHIST)
DOM. ECONOMY SALES	HETDMME	(MNUMNR,NHIST)
DOM. FIRM POWER SALES $	HETDMDF	(MNUMNR,NHIST)
DOM. ECONOMY SALES $	HETDMDE	(MNUMNR,NHIST)
IMPORTS -- FIRM	HETIMPF	(MNUMNR,NHIST)
IMPORTS -- ECONOMY	HETIMPE	(MNUMNR,NHIST)
IMPORTS -- REVENUES	HETIMPD	(MNUMNR,NHIST)
EXPORTS -- FIRM	HETEXPF	(MNUMNR,NHIST)
EXPORTS -- ECONOMY	HETEXPE	(MNUMNR,NHIST)
DOM. ECON. TRAD PROFIT $	HETDMPE	(MNUMNR,NHIST)
EXPORTS -- REVENUES	HETEXPD	(MNUMNR,NHIST)
PURCH. PWR COST -- FIXED CAP	HPPCAP	(MNUMNR,NHIST)
PURCH. PWR COST -- VAR O&M	HPPOM	(MNUMNR,NHIST)
PURCH. PWR COST -- FUEL	HPPFUEL	(MNUMNR,NHIST)

Notes:

*1=Utility, 2=Nonutility ('NUG')
F861 - "Annual Electric Utility Report".
F867 - "Annual Nonutility Power Producer Report".
FE-781R - "Annual Report of International Electrical Export/Import Data".
EPA 92 - Department of Energy, Electric Power Annual 1992 (DOE/EIA - 0348(92)), draft report, January 1994.
OIAF - Energy Information Administration, Office of Integrated Analysis and Forecasting, Energy Supply and Conversion Division.

Table A2-10: control Common Description

Variable	Field	Indices	Units	Source
UFPTOL	Fuel Price Tolerance	None	Numeric	Assumption
EFD$NERC	Demand - EFD	MNUMNR	GWH	Demand Modules
EFD$CENSUS	Demand - EFD	MNUMCR	GWH	Demand Modules
ECP$NERC	Demand - ECP	MNUMCR,ECP$FPH	GWH	Demand Modules

ECP$CENSUS	Demand - ECP	MNUMCR,ECP$FPH	GWH	Demand Modules
UFELAS	FUEL PRICE ELASTICITY	EFD$NFL	Numeric	
UFLCVGA	Fuel convg. tolerance	EFD$NFL	Numeric	
UFLCVGP	Fuel conv. Tolerance %	EFD$NFL	Numeric	
UFLSMF	FUEL SMOOTHING FACTOR	EFD$NFL	Numeric	
UFPTOL	FUEL PRICE TOLERANCE		Numeric	
UMXPCH	MAX FUEL PRICE CHANGE	EFD$NFL	Numeric	
URFURB	HEATRATE improvement factor for refurbishments		Numeric	
BARRIER	ALLOW TRADE	MNUMYR	Numeric	
UHBSYR	HISTORICAL BASE YEAR FOR EMM		Numeric	
UESTYR	INITIAL EXECUTION YEAR FOR EMM (DATA)		Numeric	
ULSTYR	INITIAL EXECUTION YEAR FOR LDSM		Numeric	
UDSTYR	INITIAL EXECUTION YEAR FOR EFD		Numeric	
UPSTYR	INITIAL EXECUTION YEAR FOR ECP		Numeric	
UFSTYR	INITIAL EXECUTION YEAR FOR EFP		Numeric	
UFLMXITR	Maximum iteration for fuel price revisions		Numeric	
UF_CN2	CANADIAN SPLY FILE		Numeric	
UFLSTITR	START ITERATION FOR FUEL PRICE REVISIONS		Numeric	
UF_EFD	EFD SPLY FILE		Numeric	
UF_MC	FILE UN #		Character	
UF_MSG	FILE UN # FOR ROUTINE MESSAGES		Character	
UF_TRAN	ETT TRANS FILE		Character	
UIFPLT	NUMBER OF FUELS PER PLANT GROUP		Numeric	
ULCVSW	USER SWITCH to output EFD load curves to EMMPR		Numeric	
UMP_COLR	Map coal to census&EMM regs	EFD$MFRG,2	Numeric	
UMP_GASR	Map gas to census&EMM regs	EFD$MFRG,2	Numeric	
UNFLRG	EFD fuel index number	EFD$NFL	Numeric	
URGNUM	NERC region numeric code	MNUMNR	Numeric	
USW_BILD	USER SWITCH (NOT USED NOW)		Numeric	
USW_DISP	USER SWITCH TO READ INPTDAF FILE		Numeric	
USW_EIJ	USER SWITCH (NOT USED NOW)		Numeric	
USW_LDC	USER SWITCH for load curves =1 LDSM, =0 NERC		Numeric	
USW_LRN	USER SWITCH FOR LEARNING		Numeric	
USW_OVER	USER SWITCH FOR HIST/STEO OVERRIDES		Numeric	
USW_OWN	USER SWITCH OWNERSHIP		Numeric	
USW_RNW	Switch from EMM RENEW run option = 0: NO Integration;			
	=1 overwrite ECP input values and int cap factors w/ RENEW			
	= 2: Overwrite RENEW w/ EMM forecasts			
USW_XP	USER SWITCH FOR DEBUG OUTPUT		Numeric	
UCYEAR	Model yr codes (E.G., '1998')	MNUMYR	Character	
UQELFAC	Multiplier for demand sensitiv.	MNUMYR	Numeric	
USW_CEL	Switch to implement demand mult case (0=none,1=base,		Numeric	
	2=demand,3=fuel prc,4=ROE,5=%equity,6=ICR,7=tech cost)			
UQELPCT	% CHANGE IN DEMAND FOR MDR CASES		Numeric	
UPFLPCT	% CHANGE IN COAL/GAS PRICES FOR MDR		Numeric	
UPCEPCT	PCT POINT CHANGE IN COST EQUITY FOR MDR		Numeric	
USW_MDR	SWITCH TO MDR CASES		Numeric	
UPOMPCT	% MULTIPLIER FOR O*M COSTS		Numeric	
USW_POL	SWITCH TO IMPLEMENT POLICY RESTRUCTUR.		Numeric	
USW_EE	SWITCH TO IMPLEMENT EE BASE CASE		Numeric	
UPOVRE	Overnight cap cost overrides	ECP$CAP,MNUMYR	Numeric	
UPXPFL	Multiplier for expectations	ECP$NFL	Numeric	
UIOL	Index: Coal from Old Units with Low Emission Standards			
UIOM	Index: Coal from Old Units with Medium Emission Standard			
UIOH	Index: Coal from Old Units with High Emission Standards			
UINL	Index: Coal from New Units with Low Emission Standards			

UINM	Index: Coal from New Units with Medium Emission Standard			
UINH	Index: Coal from New Units with High Emission Standards			
UISB	Index: Coal from Units with Scrubbers			
UIUF	Index: Uranium Fuel			
UFLCODE	EFD FUEL CODES	EFD$NFL	Character	
EPPLCD	EFD PLANT TYPE CODES	EFD$CAP	Character	
NOX_EMF	NOX Emis factors (lbs/Std Unit)	EMMBTP,EMSNFL	Numeric	
NOX_STD	NOX Emiss Stds (lbs/MMbtu)	EMM$BTP	Numeric	
NOX_CTL	NOX Reduct Fact (% Reduction)	EMM$NCT	Numeric	
SO2_EMF	SO2 Emiss Fact(lbs/Std Unit)	EMS$NFL	Numeric	
SO2_MAX	SO2 Max Emis fact(lbs/Std Unit)	EMS$NFL	Numeric	
SO2_PCT	SO2 Emis fact(% of SO2 in Fuel)	EMS$NFL	Numeric	
CNV_FAC	Convert Std unit to Alt Std Unit	EMS$NFL	Numeric	
NUM_NCT	Number NOX Control Technologies		Numeric	
NUM_BTP	# Boiler Types ; Fire Type / Bottom Type Combinations		Numeric	
NUM_EMF	# of Fuel Types for use in Specifing Emission Factors		Numeric	
NOX_PH1	Year Phase 1 plants must comply	EMM$BTP	Numeric	
NOX_PH2	Year Phase 2 plants must comply	EMM$BTP	Numeric	
NCT_NAME	NOX Control Tech Names	EMM$NCT	Character	
BTP_NAME	Boiler Type Names	EMM$BTP	Character	
EMS_FUEL	Emission Fuel Type Names	EMS$NFL	Character	
EMS_UNIT	Std Units for Emission Fuels	EMS$NFL	Character	
CNV_UNIT	Conv Un Lbl from Std to Std Un	EMS$NFL	Character	
BTP_FTCD	Boiler Type - Fire Type Codes	EMM$BTP	Character	
NCT_CODE	NOX Control Tech Codes	EMM$BTP	Character	
BTP_BTCD	Boiler Type-Bottom Type Codes	EMM$BTP	Character	
UF_DBS	FILE UN # for EMM database output file		Numeric	
USYEAR	Year	MNUMYR	Numeric	
UNYEAR	Number of Years		Numeric	
UNRGNS	Number of regions in current run	Numeric		
UF_IN	File ID (unit) for INPTDAF File (Local)		Numeric	
UF_OUT	File ID (unit) for OUTDAF File (Local)		Numeric	
UF_PLT	File ID (unit) for Plant DAF File (Local)		Numeric	
UF_CRV	File ID (unit) for Load Curve File(L)		Numeric	
UF_DBG	File ID (unit) for Debug File (Local)		Numeric	
UF_SO2	File ID (unit) for SO2 Control File (L)		Numeric	
UZ_PLT	File ID (unit) for Plant DAF File(Global)		Numeric	
UZ_IN	File ID (unit) for an input File (Global)		Numeric	
UZ_CRV	File ID (unit) for Load Curve File (G)		Numeric	
UF_LD	File ID (unit) for Load DAF File (Local)		Numeric	
UZ_LD	File ID (unit) for Load DAF File (Global)		Numeric	
UF_TMP	File ID (unit) for Temp. File (Local)		Numeric	
UF_RP2	File ID (unit) for 2nd Report File (L)		Numeric	
UF_RPT	File ID (unit) for 1st Report File (L)		Numeric	
UF_FL	File ID (unit) for Fuel DAF File (Local)		Numeric	
UNFUELS	Number of Fuel Types		Numeric	Assumption
UNFLRG	Fuel Index		Numeric	Assumption
USW_ECP	Switch to turn on ECP		Numeric	
FLBASE			Numeric	
FLLAST			Numeric	
UNFLRGS			Numeric	
USW_NERC	Input Fuel Price Switch (NERC)		Numeric	Assumption
USW_CNES	Input Fuel Price Switch (CENSUS)		Numeric	Assumption
USW_GASR	Input Fuel Price Switch (Gas)		Numeric	Assumption
USW_CLRG	Input Fuel Price Switch (Coal)		Numeric	Assumption
UF_ETT	File ID (unit) for ETTDBUG File	Numeric		

UF_ETTIN	File ID (unit) for ETTIN File		Numeric	
UF_ETTDF	File ID (unit) for ETTDF File		Numeric	
UF_BLD	File ID (unit) for BUILD File		Numeric	
UF_BOUT	File ID (unit) for BILDOUT File		Numeric	
UF_CNCT	File ID (unit) for ETCNCT (Contracts) File		Numeric	
UF_ETDM	File ID (unit) for ETTDEM File		Numeric	
USW_ETT	Switch to turn on ETT		Numeric	
UZ_ETT	ETT Switch (not in use)		Numeric	
USW_UCAPE	Switch to turn on old ECP		Numeric	
USW_RNW	Switch to turn on Renewables		Numeric	
URGNME	Region Names	MNUMNR	Alpha	Assumption
UNMFL		EFD$NFL	Alpha	
UF_SCEN	Name of Scenario		Alpha	
UCDFLRG		EFDNFL,EFDMFRG	Alpha	
UPFLRG		EFD$MFRG	Alpha	
UILL	Low Sulfur Lignite Coal		Numeric	Assumption
UILM	Medium Sulfur Lignite Coal		Numeric	Assumption
UILH	High Sulfur Lignite Coal		Numeric	Assumption
UILV	Very High Sulfur Coal		Numeric	Assumption
UISL	Low Sulfur Subbituminous Coal		Numeric	Assumption
UISM	Medium Sulfur Subbituminous Coal		Numeric	Assumption
UISH	High Sulfur Subbituminous Coal		Numeric	Assumption
UISV	Very High Sul. Subbituminous Coal		Numeric	Assumption
UIBL	Low Sulfur Bituminous Coal		Numeric	Assumption
UIBM	Medium Sulfur Bituminous Coal		Numeric	Assumption
UIBH	High Sulfur Bituminous Coal		Numeric	Assumption
UIBV	Very High Sulfur Bituminous Coal	Numeric		Assumption
UIDS	Distillate Oil		Numeric	Assumption
UIRL	Residual Low Sulfur Oil		Numeric	Assumption
UIRH	Residual High Sulfur Oil		Numeric	Assumption
UIGF	Natural Gas - Firm		Numeric	Assumption
UIGI	Natural Gas - Interruptible		Numeric	Assumption
UIUR	Uranium		Numeric	Assumption
UIGC	Natural Gas - Competitive		Numeric	Assumption

TABLE A2-11: bildin Common Block Description

The bildin common contains input data for the ECP that will change by region and over time. This common is stored in a direct access file by NERC region. Also included in this common block, the clexput common contains data for coal price expectation equations.

Variable	Indices	Description	Units	Source
ECP Load data				
EP$LF	(ECPVLS,ECPXPH)	LOAD FOLLOWING FAC BY LOAD/YR		
EPFPM	(ECPMSP,ECPXPH)	Preventive Maintenance Seasonal Factor		
EPHGHT	(ECPVLS,ECPXPH)	HEIGHT OF VERTICAL LOAD SEGS		
EPPEAK	(ECP$XPH)	PEAK LOAD		
EPSPK	(ECPMSP,ECPXPH)	SEASONAL PEAK LOAD		
EPWDTH	(ECPVLS,ECPXPH)	WIDTH OF VERTICAL LOAD SEGS		
EORDER	(ECPVLS,ECPXPH)	Order After Preventive Maintenance and interrregional transfers		
EPFRST	(ECPMSP,ECPXPH)	FIRST VLS PER ECP SEASON		
EPGECP	(ECP$STP)	LOAD GROUP TO ECP SEASON MAP		
EPGETT	(ECP$STP)	LOAD GROUP TO ETT(EFD) SEASON MAP		
EPLDGR	(ECPVLS,ECPXPH)	LOAD GROUP (E.G. SUMMER DAY)		
EPLDSG	(ECPVLS,ECPXPH)	LOAD SEGMENT(E.G. PEAK,OFFPK)		
EPLMAP	(ECPSTP,ECPSSZ,ECP$XPH)	LOAD GROUP TO ECP STEP MAP		
EPLMAP	(ECPSTP,ECPSSZ,ECP$XPH)	LOAD GROUP TO ECP STEP MAP		

EPNEXT	(ECPVLS,ECPXPH)	NEXT VLS PER ECP SEASON
EPNGRP		NUMBER OF ECP GROUPS (<=ECP$STP)
EPNMSP		NUMBER OF ECP SEASONS (<=ECP$MSP)
EPNSPG	(ELD$DAY)	NUMBER OF STEPS PER GROUP
EPNSTP	(ECP$XPH)	NUMBER OF VERTICAL STEPS
EPSETT	(ECP$MSP)	ECP SEASON TO ETT(EFD) SEASON

ALL ECP TECHNOLOGIES

EPECAP	(ECPCAP,ECPXPH)	Existing Generation Capacity
EPEXT	(ECP$CAP,MNPOLLUT+1)	Externality Costs
EPNCAP	(ECP$CAP)	New Capacity For New Technologies
EPRGM	(ECP$CAP)	Regional Cost Multipliers
EPACM	(ECP$CAP)	Regional Ambient Conditions Multipliers
EPHTRT	(ECP$CAP)	Current Heat Rate
EPPHRT0	(ECP$DSP)	Initial Heat Rate
EPPHRTN	(ECP$DSP)	Final Heat Rate

INTERMITTENT + DISPATCHABLE RENEWABLES CAPACITY

EPBLDBND	(ECP$I_R)	CAPACITY BUILD BOUND
EPCH4RT	(ECP$I_R)	CH4 EMISSION RATE
EPCO1RT	(ECP$I_R)	CO EMISSION RATE
EPCO2RT	(ECP$I_R)	CO2 EMISSION RATE
EPCRBRT	(ECP$I_R)	CARBON EMISSION RATE
EPNOXRT	(ECP$I_R)	NOX EMISSION RATE
EPSOXRT	(ECP$I_R)	SO2 EMISSION RATE
EPVOCRT	(ECP$I_R)	VOC EMISSION RATE
EPIROVR	(ECP$I_R)	REGIONAL OVERNIGHT CAPITAL COSTS ($/KW)
EPIRFOM	(ECP$I_R)	REGIONAL FIXED O&M COSTS ($/KW)
EPIRVOM	(ECP$I_R)	REGIONAL VARIABLE O&M COSTS (MILLS/KWH)
EPIRCCR	(ECP$I_R)	CAPACITY CREDIT (FRACTION)

INTERMITTENT CAPACITY

EPIACF	(ECP$INT)	AVERAGE CAPACITY FACTOR
EPICFC	(ECPINT,ECPVLS)	Maximum Capacity Factor

NON-INTERMITTENT RENEWABLE CAPACITY

EPRCFC	(ECP$RNW)	Maximum Capacity Factor

FUEL CODES

EPFMAP	(ECPNFL,EFDNFL)	EFD TO ECP FUEL TYPES(ECP TYPE-CAN MIX EFD TYPES)
EPFLRG	(EFDNFL,EFDMFRG)	NERC REG MAP TO EACH FUEL REG
EPCRMP	(EFD$NFL,MNUMCR)	NERC REG MAP TO CENSUS REG
EPPFL	(ECPNFL,ECPXPH)	PV OF NOMINAL ECP FUEL PRICES

RETROFITS

EPSOVR	(ECPDSP,ECPSCR)	OVERNIGHT CAP COST-RETROFIT
EPSCAP	(ECPDSP,ECPSCR)	UPPER LIMIT-RETROFITS
EPNSCR	(ECPDSP,ECPSCR)	# PLANTS IN A RETROFIT GROUP
EPSREC	(ECPSGP,ECPDSP,ECP$SCR)	REC. #/EACH PLANT IN A RET GRP

EMISSION ALLOWANCES

EPALSO2	(ECP$XPH)	SO2 EMISSIONS ALLOWANCES
EPALNOX	(ECP$XPH)	NOX EMISSIONS ALLOWANCES
EPALCO2	(ECP$XPH)	CO2 EMISSIONS ALLOWANCES
UPDNOXL	(MNUMYR)	NOX Emission Limits (lbs./mmBtu)

OWNUSE CAPACITY TO ADD TO DEMAND- IPPS AND NONTRAD COGEN

EOUNCP		OWNUSE PORTION OF IPP CAP
EOUCCP		OWNUSE PORTION OF COGEN CAP

FINANCIAL PARAMETERS

EPDSCRT		UTIL DSC RT (NOM, TAX ADJ ROR)
EPUROR		UTIL ROR (WGT AVG CE,PE,DEBT)
EPUIRT		UTIL INTEREST RATE
EPUFDT		UTIL DEBT FRACTION
EPUFPE		UTIL ((CE*FRAC+PE*FRAC)/ROR)
EPUCRE		UTIL COMMON RETURN ON EQUITY
EPRTBS		INITIAL RATE BASE
EPMRM		MIN RESERVE MARGIN-PLANNING

INTER-REGIONAL TRADE

EPXPRT	(ECP$XPH)	ELECTRICITY EXPORT LIMITS
EPCOVR	(ECP$CAP)	OVERNIGHT COST TRANSMISSION
EPCTRM	(ECP$CAP)	ADD ON TRANSMISSION COST
EPCCRF	(ECP$CAP)	FIXED CHARGE FACTOR TRANS.
EPCFOM	(ECP$CAP)	FIXED O&M TRANSMISSION
EPTCST	(MNUMNR)	TRANSM. COST FOR IRT BLDS
EPTCRF	(MNUMNR)	TRANSM. ANN. FACTOR-IRT BLDS
EPTLOSS	(MNUMNR)	TRANSM. LOSS FOR IRT BLDS
EPTIRGN	(MNUMNR)	TRANSM. IMPORT REG-IRT BLDS

PURCHASED POWER

EPUPCLF	(ECP$XPH)	PURCHASED CAP LIMIT FACT-UTIL
EPNPCLF	(ECP$XPH)	PURCHASED CAP LIMIT FACT-NUG
EPPCLRHS	(ECP$XPH)	PURCHASED CAP LIMIT RHS VALUE

REGIONAL MAPS (CENSUS MAP MAY BE DIFFERENT FOR DIFFERENT PLANT/FUELS)

EPCENSUS	(ECP$CAP)	CENSUS REGION BY PLANT TYPE
EPNGRG		NATURAL GAS REGION
EPCLRG		COAL REGION

BUILD BOUND TYPE FOR NEW CAPACITY

EPBNDTYP	(ECP$I_R)	BUILD BOUND TYPE-E,G,L-INT CAP	character
EPLOVR	(ELFT$BLD)	LFTOVR BYTES-END OF LAST BLOCK	character

clexput CONTAINS DATA FOR COAL PRICE EXPECTATIONS EQUATIONS

UPCOEFC	(MNUMNR,ECP$NCC)	COEFF-COAL PRC EXP. EQUATIONS
XPCLELN	(MNUMNR,MNXYR)	EXPECTED COAL PRICE--NERC RGN

TABLE A2-12: cogen Common Description

Most of these variables are from either the Industrial and/or Commercial NEMS model. The commercial, industrial and other capacity values are decremented from demand prior to the dispatch decision.

Variable	Description	Indices	Units	Source
Cogeneration at Other Facilities				
CGOTCAP	Capacity (Other)	(NRGN,YR,FUEL)	MW	F867
CGITGEN	Generation (Other)	(NRGN,YR,FUEL)	MWH	F867
CGOTHR	Heat Rates (Other)	(FUEL)	Btu/kwh	Assumption

Non-Traditional Cogeneration - Existing & Planned (F867)

CGNTCAP	Capacity (NT)	(NRGN,YR,FUEL)	MW	F867
CGNTGEN	Generation (NT)	(NRGN,YR,FUEL,2)	MWH	F867
CGNTQ	Consumption (NT)	(NRGN,YR,FUEL)		F867

Non-Traditional Cogeneration - Unplanned Capacity

UCAPCSC	Coal Steam (NT)	(NRGN,YR)	MW	
UCAPOSC	Other Steam (NT)	(NRGN,YR)	MW	
UCAPCCC	Comb Cycle (NT)	(NRGN,YR)	MW	
UCAPCTC	Combustion Turbine (NT)	(NRGN,YR)	MW	
UCAPHYC	Conv. Hydro (NT)	(NRGN,YR)	MW	
UCAPGEC	Geotherman (NT)	(NRGN,YR)	MW	
UCAPMSC	MSW (NT)	(NRGN,YR)	MW	
UCAPWDC	Biomass (NT)	(NRGN,YR)	MW	
UCAPSTC	Solar Thermal (NT)	(NRGN,YR)	MW	
UCAPPVC	Photovoltaic (NT)	(NRGN,YR)	MW	
UCAPWNC	Wind (NT)	(NRGN,YR)	MW	
UCAPTLC	Total (NT)	(NRGN,YR)	MW	

Non-Traditional Cogeneration - ‘Unplanned' Generation

CGNCLNR	Coal Generation (NT)	(NRGN,YR)	MWH	
CGNDSNR	Distillate Generation (NT)	(NRGN,YR)	MWH	
CGNRLNR	Resid Low Generation (NT)	(NRGN,YR)	MWH	
CGNRHNR	Resid Hi Generation (NT)	(NRGN,YR)	MWH	
CGNGFNR	Firm Gas Generation (NT)	(NRGN,YR)	MWH	
CGNGINR	Interruptible Gas Gen (NT)	(NRGN,YR)	MWH	
CGNGCNR	Competitive Gas (NT)	(NRGN,YR)	MWH	
CGNHYNR	Conventional Hydro (NT)	(NRGN,YR)	MWH	
CGNGENR	Geothermal Generation (NT)	(NRGN,YR)	MWH	
CGNMSNR	MSW Generation (NT)	(NRGN,YR)	MWH	
CGNWDNR	Wood Generation (NT)	(NRGN,YR)	MWH	
CGNSTNR	Solar Thermal Generation (NT)	(NRGN,YR)	MWH	
CGNPVNR	Photovoltaic Generation (NT)	(NRGN,YR)	MWH	
CGNWNNR	Wind Generation (NT)	(NRGN,YR)	MWH	
CGNTLNR	Total (NT)	(NRGN,YR)	MWH	

Cogeneration Output from Refineries

CGREQ	Fuel Consumption (Refinery)	(CRGN,YR,FUEL,TYP)	MMM Btu	Refinery/F867
CGRECAP	Capacity (Refinery)	(CRGN,YR,FUEL,TYP,VIN)GW	Refinery/F867	
CGREGEN	Generation (Refinery)	(CRGN,YR,FUEL,TYP)	GWH	Refinery/F867

Cogeneration Output from Enhanced Oil Recovery (EOR) Facilities

CGOGQ	Heat Rates (EOR)	(CRGN,YR,FUEL,TYP)	Btu/kwh EOR/F867	
CGOGCAP	Oil & Gas Cogen Capacity(EOR)	(CRGN,YR,FUEL,TYP,VIN)GW	EOR/F867	
CGOGGEN	Generation (EOR)	(CRGN,YR,FUEL,TYP)	GWH	EOR/F867

Total Cogen Output from Industrial Sector (including Refineries and EOR)

CGINDQ	Fuel Consumption (Industrial)	(CRGN,YR,FUEL,TYP)	MMM Btu	Industrial/F867
CGINDCAP	Capacity (Industrial)	(CRGN,YR,FUEL,TYP,VIN)GW	Industrial/F867	
CGINDGEN	Generation (Industrial)	(CRGN,YR,FUEL,TYP)	GWH	Industrial/F867

Commercial Module Cogen Variables

CGCOMGEN	NUGS Generation	(CRGN,YR,FUEL)	GWH	Commercial/F867
CGCOMQ	NUGS Sales to Grid	(CRGN,YR,FURL)	MMM Btu	Commercial/F867
CGCOMCAP	NUGS Capacity	(CRGN,YR,FUEL,TYP)	GWH	Commercial/F867
GRIDSHR	Grid/Own Use Shares	(CRGN,YR)	Numeric	Commercial/F867

Report Writer Variables				
CGTLCAP	Total Cogen Capacity	(NRGN,YR)	GW	ECP Output/F867
Cogen Renewables by Type				
CGTLGEN	Cogen Generation(Grid & Own Use)	(NRGN,YR,TYP)	GWH	EFD Output/F867
CGRWCAP	Cogen Capacity (Renewables)	(NRGN,YR,TECH)	GW	ECP Output/F867
CGRWGEN	Cogen Generation (Renewables)	(NRGN,YR,TECH)	GWH	EFD Output/F867
CGRWQ	Fossil Fuel Equi. (Renewables)	(NRGN,YR,TECH)	trills	Assumption

Notes:
CRGN subscript values = 1 through 9 (Census Regions)
NRGN subscript values = 1 through 16 (EMM Regions)
YR subscript values = 1 through 29 (1990-2015, 2020, 2025, 2030)
FUEL subscript values = 1 through 10 (for all except Refinery and EOR)
10 Fuel types (1=coal,2=oil,3=gas,4=hydro,5=geo,6=msw,
7=biomass,8=solar,9=other gas fuel,10=other);
In Refinery: 5 fuels (1=other gas fuel,2=oil,3=gas,4=msw,5=other);
In EOR: 4 fuels (1=coal,2=oil,3=gas,4=other/renew)
TYP subscript values = 1 through 2 (1=electricity sold to utilities,
2=electricity for own-use)
VIN subscript values = 1 through 2 (1=existing and planned, 2=unplanned)
TECH subscript values = 1 through 8 (renewable technology types)

Table A2-13: emmgeo Common Block Description

Variable	Indices	Description	Units
emmgeo Common stores cumulative builds for geothermal/biomass			
GEOBLDS	(MNUMNR,MNUMYR+ECP$XPH)	CUMULATIVE GEO BUILDS	mw
BIOBLDS	(MNUMNR,MNUMYR+ECP$XPH)	CUMULATIVE BIO BUILDS	mw
geoplt Common stores input data on geothermal units for geo model			
GE_NMPC	(300)	NAMEPLATE CAPACITY	mw
GE_SUMC	(300)	SUMMER CAPACITY	mw
GE_WINC	(300)	WINTER CAPACITY	mw
GE_OWNR	(300)	OWNERSHIP CODE (1 = private,2 = public,3 = nonutility)	
GE_NREG	(300)	NERC REGION	numeric
GE_STYR	(300)	START YEAR	numeric
GE_STMO	(300)	START MONTH	numeric
GE_STAT	(300)	STATUS CODE (1=existing,2=planned addition,3=unplanned addition)	
GE_NUNTS		NUMBER OF GEO. UNITS	numeric
GE_COMP	(300)	COMPANY ID	character
GE_PLID	(300)	PLANT ID	character
GE_UNIT	(300)	UNIT ID	character
GE_PLNM	(300)	PLANT NAME	character
GE_STATE	(300)	STATE CODE	character

Table A2-14: emission Common Block Description

Variable	Indices	Description	Source
Emission variables			
EMRFSA	(MNUMYR)	Sulfur allowances	
EMELPSO2	(MNUMYR)	ECP Sulfur dioxide emission allowance price	
EMUMM	(MNUMYR)	Spent nuclear fuel discharges	
EMRS	(4,MNPOLLUT,MNUMYR)	Resd Emissions of Air Pollutants	
EMRSC	(MNUMCR,MNPOLLUT,MNUMYR)	Resd Emissions by Region	

EMCM	(5,MNPOLLUT,MNUMYR)	Comm Emissions by Air Pollutants
EMCMC	(MNUMCR,MNPOLLUT,MNUMYR)	Comm Emissions by Region
EMINC	(4,MNPOLLUT,MNUMYR)	Ind Emis by Fuel-Combustion
EMINCC	(MNUMCR,MNPOLLUT,MNUMYR)	Ind Emis by Region-Comb
EMINCN	(MNUMCR,MNPOLLUT,MNUMYR)	Ind Emis by Reg-Noncomb
EMTR	(5,MNPOLLUT,MNUMYR)	Transportation Emissions by Fuel
EMTRC	(MNUMCR,MNPOLLUT,MNUMYR)	Trans Emissions by Region
EMTRS	(5,MNPOLLUT,MNUMYR)	Trans Emissions by Trans Modes
EMNT	(MNUMCR,MNPOLLUT,MNUMYR)	NGTDM Emissions by Region
EMOGC	(MNUMCR,MNPOLLUT,MNUMYR)	Oil&Gas Emissions by Region
EMOGCS	(2,MNPOLLUT,MNUMYR)	O&G Emis by Activity (On/offshore)
EMOGF	(2,MNPOLLUT,MNUMYR)	O&G Emis by Fuel (Oil, NG)
EMEL	(4,MNPOLLUT,MNUMYR)	EMM Emissions by Fuel Type
EMELC	(MNUMCR,MNPOLLUT,MNUMYR)	EMM Emissions by Region
EMPMC	(4,MNPOLLUT,MNUMYR)	Petroleum Emis by Fuel-Combustion
EMPMCC	(MNUMCR,MNPOLLUT,MNUMYR)	PMM Emis by Regn-Comb
EMPMCN	(MNUMCR,MNPOLLUT,MNUMYR)	PMM Emis by Reg-Noncomb
EMCP	(MNUMCR,MNPOLLUT,MNUMYR)	Coal Supply Emissions by Region
EMCPS	(3,MNPOLLUT,MNUMYR)	Coal Supply Emissions by Activity
EMCS	(MNUMCR,MNPOLLUT,MNUMYR)	Coal Synthetics Emissions by Reg
EMRN	(3,MNPOLLUT,MNUMYR)	Renewable Emissions by Fuel
EMRNC	(MNUMCR,MNPOLLUT,MNUMYR)	Renewable Emissions by Region
EMCARBON	(FLTYPE,MNUMYR)	National Carbon emissions by fuel
EMRNET	(MNETOH,MNPOLLUT,MNUMYR)	Ethanol Emissions by Vol
EMRNEC	(MNETOH,MNPOLLUT,MNUMYR)	Ethanol Emissions by Reg
Policy Related Data Structures at National Level		
EMBTAX	(15,MNUMYR)	Btu Tax by Fuel
EMETAX	(15,MNUMYR)	Excise (Consumption) Tax by Fuel
EMEMTAX	(MNPOLLUT,MNUMYR)	Emissions Tax by Air Pollutant
EMLIM	(3,MNUMYR)	Emission Constraints by (CO2,SOx,NOx)
EMREV	(12,MNUMYR)	Emission Revenues by Demand Sector
SO2$RMV	(NDREG,MNUMYR,3)	Fraction of sulfur after scrubbing
EMELDSO2	(MNUMYR)	EFD sulfur dioxide emission allowance price
EMELBNK	(MNUMYR)	Banked sulfur dioxide allowances
EMELRET	(MNUMNR,MNUMYR)	scrubber retrofits

Note: MNPOLLUT = Air Pollutants (C, CO, CO2, SOx, NOx, VOC, CH4, Particulates), by Fuel type where CH4 & Particulates are reserved placeholders

FLTYPE = Fuel type (Oil, NG, MCL, SCL, Ren, Al)

Table A2-15: dispuse Common Block Description

Description	Variable	Indices	Units
Y-INT&SLOPE CURRENT CUT LINE	ESLCUT	(2,EFD$MVS)	Numeric
Y VALUES OF Ssnal LOAD CURVE	ETHGHT	(EFD$MVS)	Numeric
X VALUES OF Ssnal LOAD CURVE	ETWDTH	(EFD$MVS)	Numeric
AREA IN EACH VERTICAL SLICE	ETAREA	(EFD$MVS)	Numeric
Tot load&cum area und cut lne	EQLOAD	(2)	Numeric
GENERATION BY OWNER	BGENOWN	(MNUMNR,EFD$OWN)	Numeric
ECONOMY TRADE BY OWNER	BTRDOWN	(MNUMNR,EFD$OWN)	Numeric
FIRM TRADES	BFIRM	(MNUMNR)	Numeric
TRADITIONAL COGEN TO GRID	BTCOGEN	(MNUMNR)	Numeric
MEXICAN TRADE	BMEXICAN	(MNUMNR)	Numeric
Non traditional cogen own use	BNTCOWN	(MNUMNR)	Numeric

NUGS OWN USE	BNUGOWN	(MNUMNR)	Numeric
GENERATION REQUIREMENTS	BGENREQ	(MNUMNR)	Numeric
AVL CAP/SSNAL PER NET OF PMR	ECACAP	(EFD$MPG)	Numeric
LOAD FOLLOWING RATES	ECLFR	(EFD$MPG)	Numeric
FUEL SHARES	ECFSHR	(EFDMPG,EFDFPP)	Numeric
VARIABLE O&M COST	ECVCST	(EFD$MPG)	$/kwh
CAP IN EACH HORIZONTAL SLICE	ECDSPC	(EFD$MHS)	gw
NRG IN EACH HORIZONTAL SLICE	ECDSPE	(EFD$MHS)	gw
CUT LINE DEFINING HOR SLICE	ECDSPP	(EFD$MHS,2)	Numeric
FUEL CONS IN FUEL REGIONS	UQFUEL	(EFDNFL,EFDMFRG,EFD$OWN)	trills
Adjustment to fuel due to trade	TQFUEL	(EFDNFL,EFDMFRG)	Numeric
Fuel quant from supply modules	XQFUEL	(EFDNFL,EFDMFRG)	Numeric
Fuel price from supply modules	XPFUEL	(EFDNFL,EFDMFRG)	Numeric
FUEL QUANTITY SMOOTHED	WQFUEL	(EFDNFL,EFDMFRG)	Numeric
FUEL PRC FR PREVIOUS ITR -1	WPFUEL	(EFDNFL,EFDMFRG)	cents/mmBtu
Fuel quantity percent difference	CQFUEL	(EFDNFL,EFDMFRG)	Numeric
Fuel price percent difference	CPFUEL	(EFDNFL,EFDMFRG)	Numeric
PERCENT REMOVAL OF SO2	URFUEL	(EFDNFL,EFDMFRG)	Numeric
FUEL PRC FR PREVIOUS ITR -2	XPFUEL	(EFDNFL,EFDMFRG)	cents/mmBtu
FUEL CONS BY NERC/OWNER	UQFCONN	(EFD$NFL,MNUMNR,EFD$OWN)	trills
GEN/FUEL TYPE IN NERC REGS	UQFGENN	(EFD$NFL,MNUMNR,EFD$OWN)	trills
GEN/DSP CAP IN NERC REGS	UQPGENN	(EFD$DSP,MNUMNR,EFD$OWN)	trills
GEN/FUEL TYPE IN CENSUS REGS	UQFGENC	(EFD$NFL,MNUMCR)	Numeric
GEN/DSP CAP IN CENSUS REGS	UQPGENC	(EFD$DSP,MNUMCR)	Numeric
GEN/REN CAPACITY IN FUEL REGS	UQHGENN	(EFD$RNW,MNUMNR,EFD$OWN)	Numeric
GEN/REN CAPACITY IN FUEL REGS	UQHGENC	(EFD$RNW,MNUMCR)	Numeric
SO2 Content by Fuel Type	UQFSO2	(EFD$NFL)	Numeric
SO2 Emissions by Fuel/Census	UTSO2C	(EFD$NFL,MNUMCR)	lbs/MMbtu
NOX Emissions by Fuel/Census	UTNOXC	(EFD$NFL,MNUMCR)	lbs/MMbtu
CO2 Emissions by Fuel/Census	UTCO2C	(EFD$NFL,MNUMCR)	lbs/MMbtu
Car Emissions by Fuel/Census	UTCARC	(EFD$NFL,MNUMCR)	lbs/MMbtu
CO Emissions by Fuel/Census	UTCO1C	(EFD$NFL,MNUMCR)	lbs/MMbtu
VOC Emissions by Fuel/Census	UTVOCC	(EFD$NFL,MNUMCR)	lbs/MMbtu
SO2 EMISSIONS BY Fuel/Census	UTSO2N	(EFD$NFL,MNUMNR)	lbs/MMbtu
NOX EMISSIONS BY Fuel/Census	UTNOXN	(EFD$NFL,MNUMNR)	lbs/MMbtu
CO2 EMISSIONS BY Fuel/Census	UTCO2N	(EFD$NFL,MNUMNR)	lbs/MMbtu
CAR EMISSIONS BY Fuel/Census	UTCARN	(EFD$NFL,MNUMNR)	lbs/MMbtu
CO EMISSIONS BY Fuel/Census	UTCO1N	(EFD$NFL,MNUMNR)	lbs/MMbtu
VOC EMISSIONS BY Fuel/Census	UTVOCN	(EFD$NFL,MNUMNR)	lbs/MMbtu
NOX emission rat by boiler typ and fuel	UFBNOX	(EMMBTP,EFDNFL,EFD$MFRG)	
# POINTS DEFINING LOAD CURVE	ETNVCT		Numeric
TEST VAR(LOAD MET=1,ELSE=0)	EIDCHK		Numeric
TEST VAR(LOAD MET=1,ELSE=0)	EIDCH2		Numeric
# HOR SLICES REQ TO MEET LOAD	ECDSPN		Numeric
MERIT ORD MAP (1=MOST ECON)	ECTYP	(EFD$MPG)	Numeric
PLT TYPE/EACH HOR SLICE	ECDSPT	(EFD$MHS)	Numeric
DUAL-FIRED RL USE--GAS REGS	TQDFRLG	(21)	Numeric
DUAL-FIRED RH USE--GAS REGS	TQDFRHG	(21)	Numeric
TEMP TOTAL FOR MIN GAS SHR	TSGCMIN	(21)	Numeric
TEMP TOTAL FOR MIN G/O RAT	TRGCMIN	(21)	Numeric
TEMP TOTAL FOR MAX GAS SHR	TSGCMAX	(21)	Numeric
TEMP TOTAL FOR MAX G/O RAT	TRGCMAX	(21)	Numeric
TEMP TOTAL FOR PAR GAS SHR	TSGCPAR	(21)	Numeric
TEMP TOTAL FOR PAR G/O RAT	TRGCPAR	(21)	Numeric
MIN GAS SHR--DF PLANTS	USGCMIN	(EFD$MPG)	Numeric
G/O PRC RAT--MIN GAS USE	URGCMIN	(EFD$MPG)	Numeric

MAX GAS SHR--DF PLANTS	USGCMAX	(EFD$MPG)	Numeric
G/O PRC RAT--MAX GAS USE	URGCMAX	(EFD$MPG)	Numeric
MAX GAS SHR--DF PLANTS	USGCPAR	(EFD$MPG)	Numeric
G/O PRC RAT--MAX GAS USE	URGCPAR	(EFD$MPG)	Numeric

Table A2-16: dispout Common Block Description

Description	Variable	Indices	Units
Domestic Economy Sales	ETDMDE		MM$
Domestic Economy Sales	ETDMME		Thous.MWH
Domestic Economy Trade Profit	ETDMPE		MM$
Domestic Firm Power Sales	ETDMDF		MM$
Domestic Firm Power Sales	ETDMMF		Thous.MWH
Marginal Cost by s,v-slice3-23	MARCST	(EFDMSP,EFDMVS)	
Marginal Cost showing last dispatched	MARCST2	(EFDMSP,EFDMVS)	
Variable O&M by Company Type	ERTOM	(EFD$OWN)	
Reserve Margin Achieved	EEMRM		
Total Fuel Cost by Co. Type	ERTFL	(EFD$OWN)	
Total SO2 Allowances	ETALLW		
Total SO2 Emissions	ETSO2		
Total NOX Emissions	ETNOX		
Total CO2 Emissions	ETCO2		
Total Car Emissions	ETCAR		
Total CO1 Emissions	ETCO1		
Total VOC Emissions	ETVOC		
Total Generation	ETGEN		
Generation by NUGS for Own Use	EWGOWN		
EWG - Rev. fr Utl	EWGREV		
EWG FIXED $ COMPONT	EWGFIX		
Commercial Cogen - Rev. fr Utl	EWGRCC		
Industrial Cogen - Rev. fr Utl	EWGRIC		
NUGS/Renewables - Rev. fr Utl	EWGRNW		
SO2 Allowances by Compl. Grp	EGALLW	(EFD$SO2)	
SO2 Penalty Cost by Compl. Grp	EGPSO2	(EFD$SO2)	
SO2 Emissions by Compl. Grp	EGSO2	(EFD$SO2)	
Summer Capacity (End-Year)	ECSCAP	(EFDDSP,EFDVIN,EFD$OWN)	
Cum. Retirements (End-Year)	ECSRET	(EFDDSP,EFDOWN)	
Variable O&M by Plant Type	ERPOM	(EFD$DSP)	
Fuel Cost by Plant Type	ERPFL	(EFD$DSP)	
Generation by Plant Type	EQPGN	(EFDDSP,EFDOWN)	
Avg. Annual Cap. by Plant Type	EQPCP	(EFD$DSP)	
Fuel Consumption by Plant Type	EQPFL	(EFD$DSP)	
Import Revenues	ETIMPD		MM$
Export Revenues	ETEXPD		MM$
Imports (Firm)	ETIMPF		Thous.MWH
Exports (Firm)	ETEXPF		Thous.MWH
Imports - Economy	ETIMPE		Thous.MWH
Economy	ETEXPE		Thous.MWH
SO2 Emissions by Plant Type	EQPSO2	(EFD$DSP)	
NOX Emissions by Plant Type	EQPNOX	(EFD$DSP)	
CO2 Emissions by Plant Type	EQPCO2	(EFD$DSP)	
Fuel Cost by Fuel Type	ERFFL	(EFD$NFL)	
Generation by Fuel Type	EQFGN	(EFDNFL,EFDOWN)	
Fuel Consumption by Fuel Type	EQFFL	(EFDNFL,EFDOWN)	

SO2 Emissions by Fuel Type	EQFSO2	(EFD$NFL)	
NOX Emissions by Fuel Type	EQFNOX	(EFD$NFL)	
CO2 Emissions by Fuel Type	EQFCO2	(EFD$NFL)	
Avg. Fuel Price by Fuel Type	EPFUEL	(EFD$NFL)	
Avg. SO2 Content by Fuel Type	EFRSO2	(EFD$NFL)	
Avg. NOX Content by Fuel Type	EFRNOX	(EFD$NFL)	
Avg. CO2 Content by Fuel Type	EFRCO2	(EFD$NFL)	
Avg. Btu Content by Fuel Type	EFHCNT	(EFD$NFL)	
Summer Capacity (End-Year)	EHSCAP	(EFDRNW,EFDVIN,EFD$OWN)	
Cum. Retirements (End-Year)	EHSRET	(EFDRNW,EFDOWN)	
Generation by Ren. Technology	EQHGN	(EFDRNW,EFDOWN)	
Var. O&M by Ren. Tech, OWN	ERHOM	(EFDRNW,EFDOWN)	
Avg. Annual Cap. by Ren. Tech	EQHCP	(EFD$RNW)	
Gen. by Plant Type and Season	EGENPS	(EFDDSP,EFDMSP)	
Cap. Req. by Plant Type&Season	EAVLPS	(EFDDSP,EFDMSP)	
Cap. Avail. by Plant Type&Ssn	ECAPPS	(EFDDSP,EFDMSP)	
Gen. by Ren. Technology&Season	EGENHS	(EFDRNW,EFDMSP)	
Cap. by Ren. Technology&Season	ECAPHS	(EFDRNW,EFDMSP)	
Peak Requirement by Season	EPEAK	(EFD$MSP)	
Cogen other capacity cost	EWGRXO		
Cogen other fuel cost	EWGRYO		
purch pwr costs-fixed cap	PPCAP		
purch pwr costs-var o m	PPOM		
purch pwr costs-var fuel	PPFUEL		
Number of Compliance Groups	ENSO2		
Number of Fuel Types	ENFLTP		
Name for Each Fuel Type	ENMFL	(EFD$NFL)	character
Leftover Bytes (ELFT$OUT may b e 0)	LFTOUT	(ELFT$OUT+1)	character

Table A2-17: uefdout Common Block Description
This common block contains the output of the EFD for reportwriting and to pass fuel consumption information to the fuel supply modules.

Description		Variable	Indices Units
Coal Gen by Ownership Type	UGNCLNR	(2,MNUMNR,MNUMYR)	mwh
Gas (Firm) Gen by Ownership Type	UGNGFNR	(2,MNUMNR,MNUMYR)	mwh
Gas (Int.) Gen by Ownership Type	UGNGINR	(2,MNUMNR,MNUMYR)	mwh
Gas (Comp.) Gen by Ownership Type	UGNGCNR	(2,MNUMNR,MNUMYR)	mwh
DS Gen by Ownership type	UGNDSNR	(2,MNUMNR,MNUMYR)	mwh
RL Gen by Ownership type	UGNRLNR	(2,MNUMNR,MNUMYR)	mwh
RH Gen by Ownership type	UGNRHNR	(2,MNUMNR,MNUMYR)	mwh
Nuc Gen by Ownership type	UGNURNR	(2,MNUMNR,MNUMYR)	mwh
PS Gen by Ownership type	UGNPSNR	(2,MNUMNR,MNUMYR)	mwh
Hyd (Not PS) Gen by Ownership type	UGNHYNR	(2,MNUMNR,MNUMYR)	mwh
Geothermal Gen by Ownership type	UGNGENR	(2,MNUMNR,MNUMYR)	mwh
MSW Gen by Ownership type	UGNMSNR	(2,MNUMNR,MNUMYR)	mwh
Wind Gen by Ownership type	UGNWDNR	(2,MNUMNR,MNUMYR)	mwh
Solar Gen by Ownership type	UGNSONR	(2,MNUMNR,MNUMYR)	mwh
Photovoltaic Gen by Ownership type	UGNPVNR	(2,MNUMNR,MNUMYR)	mwh
Wind Gen by Ownership type	UGNWNNR	(2,MNUMNR,MNUMYR)	mwh
Hyd/Oth Gen by Ownership type	UGNHONR	(2,MNUMNR,MNUMYR)	mwh
Tot. Gen by Ownership Type	UGNTLNR	(2,MNUMNR,MNUMYR)	mwh
COAL CONS BY OWNERSHIP TYPE	UFLCLNR	(2,MNUMNR,MNUMYR)	mwh
Gas (firm) cons by ownership Type	UFLGFNR	(2,MNUMNR,MNUMYR)	trills/MMBtu
Gas (int.) cons by ownership Type	UFLGINR	(2,MNUMNR,MNUMYR)	trills/MMbtu

Gas (comp.) cons by ownership Type	UFLGCNR	(2,MNUMNR,MNUMYR)	trills/MMbtu
DS CONS BY OWNERSHIP TYPE	UFLDSNR	(2,MNUMNR,MNUMYR)	trills/MMbtu
RL CONS BY OWNERSHIP TYPE	UFLRLNR	(2,MNUMNR,MNUMYR)	trills/MMbtu
RH CONS BY OWNERSHIP TYPE	UFLRHNR	(2,MNUMNR,MNUMYR)	trills/MMbtu
NUC CONS BY OWNERSHIP TYPE	UFLURNR	(2,MNUMNR,MNUMYR)	trills/MMbtu
PS CONS BY OWNERSHIP TYPE	UFLPSNR	(2,MNUMNR,MNUMYR)	trills/MMbtu
Hyd(not ps) cons by ownership Type	UFLHYNR	(2,MNUMNR,MNUMYR)	trills/MMbtu
OTH. CONS BY OWNERSHIP TYPE	UFLOTNR	(2,MNUMNR,MNUMYR)	trills/MMbtu
TOT CONS BY OWNERSHIP TYPE	UFLTLNR	(2,MNUMNR,MNUMYR)	trills/MMbtu
Coal Price by Ownership Type	UPRCLNR	(MNUMNR,MNUMYR)	cents/MMBtu
Gas (Firm) Price by Ownership Type	UPRGFNR	(MNUMNR,MNUMYR)	cents/MMBtu
Gas (Int.) Price by Ownership Type	UPRGINR	(MNUMNR,MNUMYR)	cents/MMBtu
Gas (Comp) Price by Ownership Type	UPRGCNR	(MNUMNR,MNUMYR)	cents/MMBtu
DS Price by Ownership Type	UPRDSNR	(MNUMNR,MNUMYR)	cents/MMBtu
RL Price by Ownership Type	UPRRLNR	(MNUMNR,MNUMYR)	cents/MMBtu
RH Price by Ownership Type	UPRRHNR	(MNUMNR,MNUMYR)	cents/MMBtu
Nuc Price by Ownership Type	UPRURNR	(MNUMNR,MNUMYR)	cents/MMBtu
Ren. Price by Ownership Type	UPRHONR	(MNUMNR,MNUMYR)	cents/MMBtu
Total SO2 Emissions by NERC	UTSO2	(MNUMNR,MNUMYR)	tons
Total NOX Emissions by NERC	UTNOX	(MNUMNR,MNUMYR)	tons
Total CO2 Emissions by NERC	UTCO2	(MNUMNR,MNUMYR)	tons
Total CO1 Emissions by NERC	UTCO1	(MNUMNR,MNUMYR)	tons
Total CAR Emissions by NERC	UTCAR	(MNUMNR,MNUMYR)	tons
Util Total Retirements by Nerc	URETTLU	(MNUMNR,MNUMYR)	Numeric
Util BWR Nuclear gener. by CENSUS	UGNUBCR	(MNUMCR,MNUMYR)	mwh
Util PWR Nuclear gener. by CENSUS	UGNUPCR	(MNUMCR,MNUMYR)	mwh
VLS Bit Coal consumption by Coal Reg	QBCELNR	(NDREG,MNUMYR)	trills/MMBtu
LS Bit Coal consumption by Coal Reg	QBDELNR	(NDREG,MNUMYR)	trills/MMBtu
MS Bit Coal consumption by Coal Reg	QBMELNR	(NDREG,MNUMYR)	trills/MMBtu
HS Bit Coal consumption by Coal Reg	QBHELNR	(NDREG,MNUMYR)	trills/MMBtu
VLS Sub Coal consumption by Coal Reg	QSCELNR	(NDREG,MNUMYR)	trills/MMBtu
LS Sub Coal consumption by Coal Reg	QSDELNR	(NDREG,MNUMYR)	trills/MMBtu
MS Sub Coal consumption by Coal Reg	QSMELNR	(NDREG,MNUMYR)	trills/MMBtu
HS Sub Coal consumption by Coal Reg	QSHELNR	(NDREG,MNUMYR)	trills/MMBtu
VLS Lig Coal consumption by Coal Reg	QLCELNR	(NDREG,MNUMYR)	trills/MMBtu
LS Lig Coal consumption by Coal Reg	QLDELNR	(NDREG,MNUMYR)	trills/MMBtu
MS Lig Coal consumption by Coal Reg	QLMELNR	(NDREG,MNUMYR)	trills/MMBtu
HS Lig Coal consumption by Coal Reg	QLHELNR	(NDREG,MNUMYR)	trills/MMBtu
Bit coal consumption by coal reg	QBTELNR	(NDREG,MNUMYR)	trills/MMBtu
Sub coal consumption by coal reg	QSTELNR	(NDREG,MNUMYR)	trills/MMBtu
Lig coal consumption by coal reg	QLTELNR	(NDREG,MNUMYR)	trills/MMBtu
Penalty cost flag 0-NOT 1-YES	FLAGSO2		Numeric
PENALTY COST $/TON OF SO2	COSTSO2		Numeric
Coal by rank convergence flag 0 - NON CONVERGED 1 - CONVERGED			
BIT COAL CONVERGENCE FLAG	FBTELNR	(NDREG)	Numeric
SUB COAL CONVERGENCE FLAG	FSTELNR	(NDREG)	Numeric
LIG COAL CONVERGENCE FLAG	FLTELNR	(NDREG-1)	Numeric
NGTDM Regions			
NG "firm" consumption by NGTDM	QGFELGR	(21,MNUMYR)	trills/MMBtu
NG "inter" consumption by NGTDM	QGIELGR	(21,MNUMYR)	trills/MMBtu
NG "compet" consumption by NGTDM	QGCELGR	(21,MNUMYR)	trills/MMBtu
NG "firm" cons by NGTDM (no hist)	EQGFELGR	(21,MNUMYR)	
NG "inter" cons by NGTDM (no hist)	EQGIELGR	(21,MNUMYR)	
NG "compet" cons by NGTDM (no hist)	EQGCELGR	(21,MNUMYR)	
VLS BIT COAL SHARE BY CL/NERC	RBCELNR	(NDREG,MNUMYR)	

VLS BIT COAL SHARE BY CL/NERC	RBCELNR	(NDREG,MNUMYR)
LS BIT COAL SHARE BY CL/NERC	RBDELNR	(NDREG,MNUMYR)
MS BIT COAL SHARE BY CL/NERC	RBMELNR	(NDREG,MNUMYR)
HS BIT COAL SHARE BY CL/NERC	RBHELNR	(NDREG,MNUMYR)
VLS SUB COAL SHARE BY CL/NERC	RSCELNR	(NDREG,MNUMYR)
LS SUB COAL SHARE BY CL/NERC	RSDELNR	(NDREG,MNUMYR)
MS SUB COAL SHARE BY CL/NERC	RSMELNR	(NDREG,MNUMYR)
HS SUB COAL SHARE BY CL/NERC	RSHELNR	(NDREG,MNUMYR)
VLS LIG COAL SHARE BY CL/NERC	RLCELNR	(NDREG,MNUMYR)
LS LIG COAL SHARE BY CL/NERC	RLDELNR	(NDREG,MNUMYR)
MS LIG COAL SHARE BY CL/NERC	RLMELNR	(NDREG,MNUMYR)
HS LIG COAL SHARE BY CL/NERC	RLHELNR	(NDREG,MNUMYR)

Shares of cogen capacity and generation by fuel type for FTABLE

Coal cogen share by nerc region	COALGEN	(MNUMNR)
Oil cogen share by nerc region	OILGEN	(MNUMNR)
Gas cogen share by nerc region	GASGEN	(MNUMNR)
Renewable cogen share by nerc	RNWGEN	(MNUMNR)
Other cogen share by nerc	OTHGEN	(MNUMNR)
TOTSHR BY NERC REGION	TOTLGEN	(MNUMNR)
Grid cogen share by nerc region	GRIDGEN	(MNUMNR)
Own use share by nerc region	OWNGEN	(MNUMNR)
Coal cogen share by nerc region	COALCAP	(MNUMNR)
Oil cogen share by nerc region	OILCAP	(MNUMNR)
Gas cogen share by nerc region	GASCAP	(MNUMNR)
Renewable cogen share by nerc	RNWCAP	(MNUMNR)
Other cogen share by nerc	OTHCAP	(MNUMNR)
TOTAL COGEN SHARE BY NERC	TOTCAP	(MNUMNR)

REPORT WRITER VARIABLES FOR REGIONAL MAPPINGS

Generation in physical region	UGNINR	(MNUMNR,MNUMYR)
Generation not in region	UGNOTR	(MNUMNR,MNUMYR)
Generation in region to serve other	UGNSRV	(MNUMNR,MNUMYR)
Fuel consumption in physical region	UFLINR	(MNUMNR,MNUMYR)
Fuel consumption not in region	UFLOTR	(MNUMNR,MNUMYR)
Fuel consumption in region for others	UFLSRV	(MNUMNR,MNUMYR)

Fuel consumption not in region	UFLOTR	(MNUMNR,MNUMYR)
Fuel consumption in region for others	UFLSRV	(MNUMNR,MNUMYR)
So2 emissions in physical region	USO2INR	(MNUMNR,MNUMYR)
So2 emission not in physical region	USO2OTR	(MNUMNR,MNUMYR)
Carbon dioxide emissions in region	UCO2INR	(MNUMNR,MNUMYR)
Carbon dioxide emssions not in region	UCO2OTR	(MNUMNR,MNUMYR)
Carbon emission in region	UCARINR	(MNUMNR,MNUMYR)
Carbon emissions not in region	UCAROTR	(MNUMNR,MNUMYR)
Nox emission in physical regions	UNOXINR	(MNUMNR,MNUMYR)
Nox emission not in regions	UNOXOTR	(MNUMNR,MNUMYR)

Table A2-18: uettout Common Block Description
This subroutine contains trade output results for reportwriting purposes.

Description	Variable	Indices	Units
NET DOMESTIC FIRM POWER	UTDMMF	(MNUMNR,MNUMYR)	mwh
NET DOMESTIC ECONOMY SALES	UTDMME	(MNUMNR,MNUMYR)	mwh

NET DOMESTIC FIRM POWER	UTDMDF	(MNUMNR,MNUMYR)	MM$
NET DOMESTIC ECONOMY SALES	UTDMDE	(MNUMNR,MNUMYR)	MM$
FIRM POWER IMPORTS	UTIMPF	(MNUMNR,MNUMYR)	mwh
ECONOMY POWER IMPORTS	UTIMPE	(MNUMNR,MNUMYR)	mwh
FIRM POWER EXPORTS	UTEXPF	(MNUMNR,MNUMYR)	mwh
ECONOMY POWER EXPORTS	UTEXPE	(MNUMNR,MNUMYR)	mwh
GROSS DOM. FIRM POWER	UTEXMF	(MNUMNR,MNUMYR)	mwh
GROSS DOM. ECONOMY SALES	UTEXME	(MNUMNR,MNUMYR)	mwh
GROSS DOM. FIRM POWER	UTEXDF	(MNUMNR,MNUMYR)	MM$
GROSS DOM. ECONOMY SALES	UTEXDE	(MNUMNR,MNUMYR)	MM$

Note: This common block is includes in the following subroutines: ETTPRC, ETRADE, ETTCOST, TRDRPT, ELEFD and ELDISP. See above parameter listing for a description of the indices of the arrays.

Table A2-19: uso2grp Common Block Description

Variable	Indices	Description
UTLSO2		Total SO2 Produced
UPNSO2	(EFD$SO2)	Next SO2 Penalty Cost
UPCSO2	(EFD$SO2)	Current SO2 Penalty Cost
UPLSO2	(EFD$SO2)	Lagged SO2 Penalty Cost
UQNSO2	(EFD$SO2)	Next Quantity of SO2 Produced
UQCSO2	(EFD$SO2)	Current Quantity of SO2 Produced
UQLSO2	(EFD$SO2)	Lagged Quantity of SO2 Produced
UQPSO2	(EFD$SO2)	Previous Quantity of SO2 Produced
UQALLW	(EFD$SO2)	Allowance for SO2
UIALLW	(EFD$SO2)	Initial SO2 Allowances
UTLSO2I		Quantity Tolerance
UTPSO2		Price Tolerance
UTJUMP		Maximum Price Jumps
UPOLD	(EFD$SO2)	Penalty Cost from Previous NEMS Iter
UNSO2		Number of Compliance Groups

Table A2-20: dispcrv Common Block Description
This common stores emm load and dispatch data needed to graph the solution of EFD. This data can be saved by region and year. At present it is not saved at all since there is no graph routine.

Variable	Indices	Units
ECSDPP	(EFD$MHS,2,EFD$MSP)	Numeric
ERYVAL	(EFDMVS,EFDMSP)	Numeric
EGYVAL	(EFDMVS,EFDMSP)	Numeric
EGXVAL	(EFDMVS,EFDMSP)	Numeric
ECSDPN	(EFD$MSP)	Numeric
EGNVCT	(EFD$MSP)	Numeric
ECSDPT	(EFDMHS,EFDMSP)	Numeric
LFTCRV	(ELFT$CRV)	Character

Table A2-21: fuelin Common Block Description
The fuelin common provides storage and archival of utility sector fuel prices. In the stand alone pc version the associated direct access file (DAF) is used to provide the required fuel prices.

Variable	Indices	Description

UPFUEL	(EFDNFL,EFDMFRG)	DELIVERED FUEL PRICES
UFRSO2	(EFDNFL,EFDMFRG)	EMISSION RATE
UFRCO2	(EFD$NFL)	CO2 EMISSION RATE
UFRCAR	(EFD$NFL)	CARBON EMISSION RATE
UFRCO1	(EFD$NFL)	CO EMISSION RATE
UFRVOC	(EFD$NFL)	VOC EMISSION RATE
UFRASH	(EFDNFL,EFDMFRG)	ASH RETENTION RATE
UFHCNT	(EFDNFL,EFDMFRG)	HEAT CONTENT
UFRGCS	(EFD$MFRG)	GAS USE IN COAL STEAM PLANTS
UFROCS	(EFD$MFRG)	OIL USE IN COAL STEAM PLANTS

Table A2-22: postpr Common Block Description

Variable	Indices	Units
COMMON/POSTPR/		
EXAVAIL	(EFDMSP,EFDMVS,ETT$MTG*(MNUMNR+EFD$PROV))	
COSTEX	(EFDMSP,EFDMVS,ETT$MTG*(MNUMNR+EFD$PROV))	
CAPEX	(EFDMSP,EFDMVS,ETT$MTG*(MNUMNR+EFD$PROV))	
NATIVE	(EFDMSP,EFDMVS,ETT$MTG*(MNUMNR+EFD$PROV))	
COSTNV	(EFDMSP,EFDMVS,ETT$MTG*(MNUMNR+EFD$PROV))	
CAPNV	(EFDMSP,EFDMVS,ETT$MTG*(MNUMNR+EFD$PROV))	
ETDSPTR	(MNUMNR,EFDMSP,EFDMHS)	Numeric
XCASTS	(MNUMNR,EFD$MHS)	Numeric
ETDSPNR	(MNUMNR,EFD$MSP)	Numeric
ETFSRR	(MNUMNR,EFDMSP,EFDMHS,EFD$FPP)	
RGENFI	(MNUMNR,EFD$FPP)	Numeric
RGENFE	(MNUMNR,EFD$FPP)	Numeric
IVWDTH	(EFDMVS,EFDMSP)	Numeric
IVGRP	(EFDMVS,EFDMSP)	Numeric
IVSEG	(EFDMVS,EFDMSP)	Numeric
HEXP	(EFDMSP,EFDMVS,ETT$MTG*(MNUMNR+EFD$PROV))	
HIMP	(EFDMSP,EFDMVS,ETT$MTG*(MNUMNR+EFD$PROV))	
ETDBIDR	(EFD$MHS,MNUMNR)	Numeric
MAP$VLS	(MNUMNR,EFDMVS,EFDMSP)	Numeric
COMMON /POSTPR2/		
ETCAPO	(EFD$MSP,MNUMNR,EFD$MHS)	Numeric
ETGENO	(EFD$MSP,MNUMNR,EFD$MHS)	Numeric
ETCSTO	(EFD$MSP,MNUMNR,EFD$MHS)	Numeric
ETCAPN	(EFD$MSP,MNUMNR,EFD$MHS)	Numeric
ETGENN	(EFD$MSP,MNUMNR,EFD$MHS)	Numeric
ETCSTN	(EFD$MSP,MNUMNR,EFD$MHS)	Numeric
TEMPC		Numeric
TEMPG		Numeric
TEMPT		Numeric
NEEDC		Numeric
NEEDG		Numeric
LINELOSS		Numeric
PRTHRESH		Numeric
CGOTPV		Numeric
CGOTPF		Numeric
CGCOMPV		Numeric
CGCOMPF		Numeric
CGINDPV		Numeric
CGINDPF		Numeric

ISHARE	(MNUMNR,MNUMCR)	Numeric
CSHARE	(MNUMNR,MNUMCR)	Numeric
IGENGN	(MNUMNR)	Numeric
IGENON	(MNUMNR)	Numeric
TEMPS2	(ETT$MTG*(MNUMNR+EFD$PROV),3)	Numeric
T1		Numeric
T2		Numeric
C2		Numeric
T3		Numeric
TEMPS	(ETT$MTG*(MNUMNR+EFD$PROV))	Numeric
TIME	(MNUMNR,EFD$MSP)	Numeric
DISPLAC	(MNUMNR-3)	Numeric
NUGFCST	(MNUMYR,MNUMNR+EFD$PROV)	Numeric
NUGVCST	(MNUMYR,MNUMNR+EFD$PROV)	Numeric
IVS		Numeric
NOTRD	(MNUMNR)	Numeric
NOPLT	(EFD$DSP)	Numeric
NVCNT		Numeric
EXCNT		Numeric
ISEASN		Numeric
TSW		Numeric
MCNT		Numeric
TRADQUAL		Numeric
MAPEX	(ETT$MTG*(MNUMNR+EFD$PROV),3)	Numeric
MAPIM	(ETT$MTG*(MNUMNR+EFD$PROV),3)	Numeric
IX		Numeric
IY		Numeric
INDXNV	(ETT$MTG*(MNUMNR+EFD$PROV))	Numeric
INDXEX	(ETT$MTG*(MNUMNR+EFD$PROV))	Numeric
ICNT		Numeric
SMAP	(ETT$MTG*(MNUMNR+EFD$PROV))	Numeric
T4		Numeric
MAPEXS	(ETT$MTG*(MNUMNR+EFD$PROV),3)	Numeric
MAPIMS	(ETT$MTG*(MNUMNR+EFD$PROV),3)	Numeric
EXCNTV		Numeric
NVCNTV		Numeric

COMMON /CNSTR/

TEMPNS	(MNUMYR)	Numeric
TEMPW	(MNUMYR)	Numeric
CNSTRE	(MNUMYR,ETT$RECS)	Numeric
CNSTRW	(MNUMYR,ETT$RECS)	Numeric
CNSTRI	(MNUMYR,ETT$RECS)	Numeric
CNSTRIW	(MNUMYR,ETT$RECS)	Numeric
CHKGEN	(MNUMNR+EFD$PROV,MNUMNR+EFD$PROV)	
CHK$	(MNUMNR+EFD$PROV,MNUMNR+EFD$PROV)	
CHKPROF	(MNUMNR+EFD$PROV,MNUMNR+EFD$PROV)	
PTHRESH1	(MNUMYR,MNUMNR+EFD$PROV,MNUMNR+EFD$PROV),	
PTHRESH2	(MNUMYR,MNUMNR+EFD$PROV,MNUMNR+EFD$PROV)	
CNSTRNTS	(EFD$MSP,MNUMYR,MNUMNR+EFD$PROV,MNUMNR+EFD$PROV)	
CNTX		Numeric
IRGEX		Numeric
IRGIM		Numeric

COMMON/UTTRPT/

ZTDMPE	(MNUMNR,2)	Numeric

ZTDMME	(MNUMNR)	Numeric
ZTDMDE	(MNUMNR)	Numeric
ZTIMPE	(MNUMNR)	Numeric
TTIMPD	(MNUMNR)	Numeric

COMMON/CANSQZ/
ECANSQZ(EFD$PROV,MNUMYR) Numeric

Table A2-23: <u>qblk</u> Common Block Description
The qblk common provides storage and archival of price/quantity variables for NEMS.

Variable	Indices	Description
QEPRS	(MNUMCR,MNUMYR)	Purch. Elec, Peak. Residential
QEPCM	(MNUMCR,MNUMYR)	Purch. Elec, Peak. Commercial
QEPTR	(MNUMCR,MNUMYR)	Purch. Elec, Peak. Transportation
QEPIN	(MNUMCR,MNUMYR)	Purch. Elec, Peak. Industrial
QEPRF	(MNUMCR,MNUMYR)	Purch. Elec, Peak. Refinery
QEPAS	(MNUMCR,MNUMYR)	Purch. Elec, Peak. All Sectors
QENRS	(MNUMCR,MNUMYR)	Purch. Elec, Nonpeak. Residential
QENCM	(MNUMCR,MNUMYR)	Purch. Elec, Nonpeak. Commercial
QENTR	(MNUMCR,MNUMYR	Purch. Elec, Nonpeak. Transportation
QENIN	(MNUMCR,MNUMYR)	Purch. Elec, Nonpeak. Industrial
QENRF	(MNUMCR,MNUMYR)	Purch. Elec, Nonpeak. Refinery
QENAS	(MNUMCR,MNUMYR)	Purch. Elec, Nonpeak. All Sectors
QELRS	(MNUMCR,MNUMYR)	Purch. Elec. Residential
QELCM	(MNUMCR,MNUMYR)	Purch. Elec. Commercial
QELTR	(MNUMCR,MNUMYR)	Purch. Elec. Transportation
QELIN	(MNUMCR,MNUMYR)	Purch. Elec. Industrial
QELRF	(MNUMCR,MNUMYR)	Purch. Elec. Refinery
QELAS	(MNUMCR,MNUMYR)	Purch. Elec. All Sectors
QGFRS	(MNUMCR,MNUMYR)	Natural Gas, Core. Residential
QGFCM	(MNUMCR,MNUMYR)	Natural Gas, Core. Commercial
QGFTR	(MNUMCR,MNUMYR)	Natural Gas, Core. Transportation
QGFIN	(MNUMCR,MNUMYR)	Natural Gas, Core. Industrial
QGFRF	(MNUMCR,MNUMYR)	Natural Gas, Core. Refinery
QGFEL	(MNUMCR,MNUMYR)	Natural Gas, Core. Electricity
QGFAS	(MNUMCR,MNUMYR)	Natural Gas, Core. All Sectors
QGIRS	(MNUMCR,MNUMYR)	Natural Gas, Noncore. Residential
QGICM	(MNUMCR,MNUMYR)	Natural Gas, Noncore. Commercial
QGITR	(MNUMCR,MNUMYR)	Natural Gas, Noncore. Transportation
QGIIN	(MNUMCR,MNUMYR)	Natural Gas, Noncore. Industrial
QGIRF	(MNUMCR,MNUMYR)	Natural Gas, Noncore. Refinery
QGIEL	(MNUMCR,MNUMYR)	Natural Gas, Noncore. Electricity
QGIAS	(MNUMCR,MNUMYR)	Natural Gas, Noncore. All Sectors
QNGRS	(MNUMCR,MNUMYR)	Natural Gas. Residential
QNGCM	(MNUMCR,MNUMYR)	Natural Gas. Commercial
QNGTR	(MNUMCR,MNUMYR)	Natural Gas. Transportation
QNGIN	(MNUMCR,MNUMYR)	Natural Gas. Industrial
QNGRF	(MNUMCR,MNUMYR)	Natural Gas. Refinery
QNGEL	(MNUMCR,MNUMYR)	Natural Gas. Electricity
QNGAS	(MNUMCR,MNUMYR)	Natural Gas. All Sectors
QGPTR	(MNUMCR,MNUMYR)	Natural Gas. Pipeline
QLPIN	(MNUMCR,MNUMYR)	Lease and Plant Fuel
QCLRS	(MNUMCR,MNUMYR)	Coal. Residential
QCLCM	(MNUMCR,MNUMYR)	Coal. Commercial

QCLIN	(MNUMCR,MNUMYR)	Coal. Industrial
QCLRF	(MNUMCR,MNUMYR)	Coal. Refinery
QCLEL	(MNUMCR,MNUMYR)	Coal. Electricity
QCLSN	(MNUMCR,MNUMYR)	Coal. Synthetics
QCLAS	(MNUMCR,MNUMYR)	Coal. All Sectors
QMCIN	(MNUMCR,MNUMYR)	Metallurgical Coal. Industrial
QMGCM	(MNUMCR,MNUMYR)	Motor Gasoline. Commercial
QMGTR	(MNUMCR,MNUMYR)	Motor Gasoline. Transportation
QMGIN	(MNUMCR,MNUMYR)	Motor Gasoline. Industrial
QMGAS	(MNUMCR,MNUMYR)	Motor Gasoline. All Sectors
QJFTR	(MNUMCR,MNUMYR)	Jet Fuel. Transportation
QDSRS	(MNUMCR,MNUMYR)	Distillate. Residential
QDSCM	(MNUMCR,MNUMYR)	Distillate. Commercial
QDSTR	(MNUMCR,MNUMYR)	Distillate. Transportation
QDSIN	(MNUMCR,MNUMYR)	Distillate. Industrial
QDSRF	(MNUMCR,MNUMYR)	Distillate. Refinery
QDSEL	(MNUMCR,MNUMYR)	Distillate. Electricity (+petroleum coke)
QDSAS	(MNUMCR,MNUMYR)	Distillate. All Sectors
QKSRS	(MNUMCR,MNUMYR)	Kerosene. Residential
QKSCM	(MNUMCR,MNUMYR)	Kerosene. Commercial
QKSIN	(MNUMCR,MNUMYR)	Kerosene. Industrial
QKSAS	(MNUMCR,MNUMYR)	Kerosene. All Sectors
QLGRS	(MNUMCR,MNUMYR)	Liquid Petroleum Gases. Residential
QLGCM	(MNUMCR,MNUMYR)	Liquid Petroleum Gases. Commercial
QLGTR	(MNUMCR,MNUMYR)	Liquid Petroleum Gases. Transportation
QLGIN	(MNUMCR,MNUMYR)	Liquid Petroleum Gases. Industrial
QLGRF	(MNUMCR,MNUMYR)	Liquid Petroleum Gases. Refinery
QLGAS	(MNUMCR,MNUMYR)	Liquid Petroleum Gases. All Sectors
QRLCM	(MNUMCR,MNUMYR)	Residual Fuel, Low Sulfur. Commercial
QRLTR	(MNUMCR,MNUMYR)	Residual Fuel, Low Sulfur. Transportation
QRLIN	(MNUMCR,MNUMYR)	Residual Fuel, Low Sulfur. Industrial
QRLRF	(MNUMCR,MNUMYR)	Residual Fuel, Low Sulfur. Refinery
QRLEL	(MNUMCR,MNUMYR)	Residual Fuel, Low Sulfur. Electricity
QRLAS	(MNUMCR,MNUMYR)	Residual Fuel, Low Sulfur. All Sectors
QRHTR	(MNUMCR,MNUMYR)	Residual Fuel, High Sulfur. Transportation
QRHEL	(MNUMCR,MNUMYR)	Residual Fuel, High Sulfur. Electricity
QRHAS	(MNUMCR,MNUMYR)	Residual Fuel, High Sulfur. All Sectors
QRSCM	(MNUMCR,MNUMYR)	Residual Fuel. Commercial
QRSTR	(MNUMCR,MNUMYR)	Residual Fuel. Transportation
QRSIN	(MNUMCR,MNUMYR)	Residual Fuel. Industrial
QRSRF	(MNUMCR,MNUMYR)	Residual Fuel. Refinery
QRSEL	(MNUMCR,MNUMYR)	Residual Fuel. Electricity
QRSAS	(MNUMCR,MNUMYR)	Residual Fuel. All Sectors
QPFIN	(MNUMCR,MNUMYR)	Petrochemical Feedstocks. Industrial
QSGIN	(MNUMCR,MNUMYR)	Still Gas. Industrial
QSGRF	(MNUMCR,MNUMYR)	Still Gas. Refinery
QPCIN	(MNUMCR,MNUMYR)	Petroleum Coke. Industrial
QPCRF	(MNUMCR,MNUMYR)	Petroleum Coke. Refinery
QPCEL	(MNUMCR,MNUMYR)	Petroleum Coke. Electricity
QPCAS	(MNUMCR,MNUMYR)	Petroleum Coke. All Sectors
QASIN	(MNUMCR,MNUMYR)	Asphalt and Road Oil. Industrial
QOTTR	(MNUMCR,MNUMYR)	Other Petr. Transp. (lubes, aviation gas)
QOTIN	(MNUMCR,MNUMYR)	Other Petroleum. Industrial
QOTRF	(MNUMCR,MNUMYR)	Other Petroleum. Refinery
QOTAS	(MNUMCR,MNUMYR)	Other Petroleum. All Sectors
QTPRS	(MNUMCR,MNUMYR)	Total Petroleum. Residential

QTPCM	(MNUMCR,MNUMYR)	Total Petroleum. Commercial
QTPTR	(MNUMCR,MNUMYR)	Total Petroleum. Transportation
QTPIN	(MNUMCR,MNUMYR)	Total Petroleum. Industrial
QTPRF	(MNUMCR,MNUMYR)	Total Petroleum. Refinery
QTPEL	(MNUMCR,MNUMYR)	Total Petroleum. Electricity
QTPAS	(MNUMCR,MNUMYR)	Total Petroleum. All Sectors
QMETR	(MNUMCR,MNUMYR)	Methanol. Transporation
QETTR	(MNUMCR,MNUMYR)	Ethanol. Transporation
QHYTR	(MNUMCR,MNUMYR)	Liquid Hydrogen. Transportation
QUREL	(MNUMCR,MNUMYR)	Uranium. Electricity
QHOIN	(MNUMCR,MNUMYR)	Hydropower. Industrial
QHOEL	(MNUMCR,MNUMYR)	Hydropower. Electricity
QHOAS	(MNUMCR,MNUMYR)	Hydropower. All Sectors
QGEIN	(MNUMCR,MNUMYR)	Geothermal. Industrial
QGEEL	(MNUMCR,MNUMYR)	Geothermal. Electricity
QGEAS	(MNUMCR,MNUMYR)	Geothermal. All Sectors
QBMRS	(MNUMCR,MNUMYR)	Biomass. Residential
QBMCM	(MNUMCR,MNUMYR)	Biomass. Commercial
QBMIN	(MNUMCR,MNUMYR)	Biomass. Industrial
QBMRF	(MNUMCR,MNUMYR)	Biomass. Refinery
QBMEL	(MNUMCR,MNUMYR)	Biomass. Electricity
QBMSN	(MNUMCR,MNUMYR)	Biomass. Synthetics
QBMAS	(MNUMCR,MNUMYR)	Biomass. All Sectors
QMSIN	(MNUMCR,MNUMYR)	Municipal Solid Waste. Industrial
QMSEL	(MNUMCR,MNUMYR)	Municipal Solid Waste. Electricity
QMSAS	(MNUMCR,MNUMYR)	Municipal Solid Waste. All Sectors
QSTRS	(MNUMCR,MNUMYR)	Solar Thermal. Residential
QSTCM	(MNUMCR,MNUMYR)	Solar Thermal. Commercial
QSTIN	(MNUMCR,MNUMYR)	Solar Thermal. Industrial
QSTEL	(MNUMCR,MNUMYR)	Solar Thermal. Electricity
QSTAS	(MNUMCR,MNUMYR)	Solar Thermal. All Sectors
QPVRS	(MNUMCR,MNUMYR)	Photovoltaic. Residential
QPVCM	(MNUMCR,MNUMYR)	Photovoltaic. Commercial
QPVIN	(MNUMCR,MNUMYR)	Photovoltaic. Industrial
QPVEL	(MNUMCR,MNUMYR)	Photovoltaic. Electricity
QPVAS	(MNUMCR,MNUMYR)	Photovoltaic. All Sectors
QWIIN	(MNUMCR,MNUMYR)	Wind. Industrial
QWIEL	(MNUMCR,MNUMYR)	Wind. Electricity
QWIAS	(MNUMCR,MNUMYR)	Wind. All Sectors
QTRRS	(MNUMCR,MNUMYR)	Total Renewables. Residential
QTRCM	(MNUMCR,MNUMYR)	Total Renewables. Commercial
QTRTR	(MNUMCR,MNUMYR)	Total Renewables. Transportation
QTRIN	(MNUMCR,MNUMYR)	Total Renewables. Industrial
QTREL	(MNUMCR,MNUMYR)	Total Renewables. Electricity
QTRSN	(MNUMCR,MNUMYR)	Total Renewables. Synthetics
QTRAS	(MNUMCR,MNUMYR)	Total Renewables. All Sectors
QEIEL	(MNUMCR,MNUMYR)	Net Electricity Imports. Electricity
QCIIN	(MNUMCR,MNUMYR)	Net Coal Coke Imports. Industrial
QTSRS	(MNUMCR,MNUMYR)	Total Energy Consumption. Residential
QTSCM	(MNUMCR,MNUMYR)	Total Energy Consumption. Commercial
QTSTR	(MNUMCR,MNUMYR)	Total Energy Consumption. Transportation
QTSIN	(MNUMCR,MNUMYR)	Total Energy Consumption. Industrial
QTSRF	(MNUMCR,MNUMYR)	Total Energy Consumption. Refinery
QTSEL	(MNUMCR,MNUMYR)	Total Energy Consumption. Electricity
QTSSN	(MNUMCR,MNUMYR)	Total Energy Consumption. Synthetics
QTSAS	(MNUMCR,MNUMYR)	Total Energy Consumption. All Sectors

Table A2-24: dispin Common Block Description

Variable	Indices	Description	
EFACTR		CONVERTS I2 TO R4(IE. * .001)	
EQEL		TOTAL ELECTRICITY DEMAND	
ERTOMF		TOTAL FIXED O&M	
EOUIPP		TOTAL IPP CAP - OWN USE	
EOUNT		TOTAL NONTRAD CAP - OWN	
EQTDLS		T&D LOSS FACTOR	
EHNTP		NUMBER OF RENEWABLE GROUPS	
EENSP		NUMBER OF SEASONAL PERIODS	
ECNTP		NUMBER OF CAPACITY GROUPS	
ECNMR		NUMBER OF MUST RUN GROUPS	
EIPGRP		NUMBER OF DSP. PLANT TYPE GRPS	
EIHGRP		NUMBER OF REN. PLANT TYPE GRPS	
EIFPLT		NUMBER OF FUELS PER PLANT	
EIMCG		NUMBER COMPLIANCE GROUPS	
ELNVCT	(EFD$MSP)	NUMBER OF POINTS IN LOAD CRV	
ELGRP	(EFDMVS,EFDMSP)	TIME OF DAY/SEASON GROUP INDEX	
ELSEG	(EFDMVS,EFDMSP)	TIME OF DAY/SEASON SEG. INDEX	
ELMAPS	(EFDSSZ,ELDDAY)	MAPS GRP / SEG TO SEASON	
ELMAPV	(EFDSSZ,ELDDAY)	MAPS GRP / SEG TO VLS	
ECFLTP	(EFDMPG,EFDFPP)	DSP PLT GRP FUEL TYPES	
ECFLRG	(EFDMPG,EFDFPP,EFD$FRG)	DSP PLT GRP SUP./RPT. REG FUEL	
ECMRUN	(EFD$MPG)	DSP PLT GRP MUST RUN INDICATOR	
ECMXCP	(EFD$MPG)	DSP PLT GRP MAX CAP FACTOR	
ECPMR	(EFD$MPG)	DSP PLT GRP PLANNED MAINT RATE	
ECFOR	(EFD$MPG)	DSP PLT GRP FORCED OUTAGE RATE	
ECASTS	(EFD$MPG)	DSP PLT GRP CAPACITY TYPE	
ECSCRB	(EFD$MPG)	DSP PLT GRP SCRUBBER EFFCY GRP	
EISO2	(EFDMPG,EFDCGP)	DSP PLT GRP COMPLIANCE GRP	
ECFOWN	(EFD$MPG)	DSP PLT GRP OWNERSHIP TYPE	
ECCR	(EFD$MPG)	DSP PLT GRP CENSUS REGION	
ECNR	(EFD$MPG)	DSP PLT GRP OWNERS NERC REGION	
ECGR	(EFD$MPG)	DSP PLT GRP GAS REGION	
ECDBID	(EFD$MPG)	DSP PLT GRP DB ID	
ECBTP	(EFD$MPG)	DSP PLT GRP BOILER TYPE	
ECNCT	(EFD$MPG)	DSP PLT GRP NOX CONTROL TYPE	
ECPHS1	(EFD$MPG)	DSP PLT GRP = 1 => PHASE 1 UNIT	
EHHYCF	(EFDMHG,EFDMSP)	NON-DSP PLT GRP CAP TYPE	
EHHYTP	(EFD$MHG)	NON-DSP PLT GRP TYPE	
EHFOWN	(EFD$MHG)	NON-DSP PLT GRP OWNER TYPE	
EHCR	(EFD$MHG)	NON-DSP PLT GRP CENSUS REGION	
EHNR	(EFD$MHG)	NON-DSP PLT GRP NERC REGION	
ECOPR	(EFD$MPG)	DSP PLT GRP PHYSICAL NERC RGN	
ECVIN	(EFD$MPG)	DSP PLT GRP VINTAGE	
ENPGRP	(EFD$DSP)	NAME OF PLANT TYPES	CHARACTER
ENHGRP	(EFD$RNW)	NAME OF RENEWABLE PLANT TYPES	CHARACTER
ELNMGRP	(ELD$DAY)	NAME OF TIME OF DAY/SSN GRPS	CHARACTER

Appendix B

B.1 Mathematical Description of Algorithms

This appendix contains a description of the FORTRAN subroutines of the EFD.

Subroutine: ELEFD

Description:	This subroutine is the main controlling module of the EFD. ELEFD initializes variables and checks a user-specified switch that determines if the trade component of the dispatch decision will be executed.
Called by:	UTIL
Source:	uefd.f
Includes:	parametr,ncntrl,emission,emmparm,control,uso2grp,dispuse,dispin,dispout,dispett,uettout
Calls:	GETSO2, GETIN, GETBLD, GETOUT, ELSO2F, ELDISP, STROUT, STRBLD, ELSO2N,ETTPRC, STRSO2
Equations:	None

Subroutine GETSO2

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

Subroutine: GETIN

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

Subroutine: GETBLD

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

Subroutine: ELDISP

Description: This subroutine initializes additional variables, reads in interruptible international trade and adjusts the load curve for planned maintenance, renewable generation and trade. It also calls the subroutines which are responsible for the dispatch decision, in particular: determining the merit order; incorporating the maintenance schedule; removing hydroelectric and other renewable facilities from the load curve; allocating the capacity; and tabulating fuel consumptions and associated costs.

Called by: ELEFD

Source: uefd.f

Includes: parametr,ncntrl,emmparm,control,dispuse,dispin,dispout,dispett,dispcrv,fuelin,uettout,bildin,postpr

Calls: ELMRIT, ELPNM, ELRNEW, ELALOC, ELCOST, LOADNG, STRETT, STREFD

Equations:

Determine the Merit Order for Dispatching

See discussion of the Subroutine ELMRIT

Determine Planned Maintenance Schedule

See discussion of the Subroutine ELPLNM

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

ECACAP(J) = (ECCAP(J,I) - ECCOPM(J,I))*.001
ECLFR(J) = 1.0 - (REAL(KMXCP) * EFACTR / ((1.0 - REAL(KFOR) * EFACTR) * (1.0 - REAL(KPMR) * EFACTR)))

Where,

ECCAP = Total existing capacity
ECCOPM = Capacity Out for Planned Maintenance
KMXCP = Maximum Capacity Factor (ECMXCP)
KPMR = Planned Maintenance Rate (ECPMR)
EFACTR = Converts integer with two significant digits to a real value with four significant digits (i.e. multiplies by .001)
KFOR = Forced Outage Rate by Capacity Type (ECFOR)

Convert International Trade Power into gigawatts for each Season

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

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

Where,

IMPANN = ETIMPE / EETIME(I)
EXPANN = ETEXPE / EETIME(I)

and,

ETIMPE = Economy Imports (mwh)
ETEXPE = Economy Exports (mwh)
EETIME = Number of Hours per Season
TOTHRS = Total Hours in the Year

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

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

Where,

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

Calculate Load (before renewables are removed from load)

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

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

Where,

IVCT = Load Slice Number

Remove Hydroelectric and Other Renewables from the Load Curve

See discussion of the Subroutine ELRNEW.

Calculate Import and Export Load Curve

Calculations are performed by region and season that create load curves representing 1) areas of generation that could be displaced by imports, referred to as "import curves", and 2) areas of generation that could be available for export, referred to as "export curves". These curves are calculated as the original load curve (XY pairs) plus or minus the region/seasonal maximum transmission constraint.

TTYVAL(IVCT) = ETHGHT(IVCT) + TRNCSTEX(I)
TIYVAL(IVCT) = ETHGHT(IVCT) - TRNCSTIM(I)

Where,

TRNCSTIM = Export Transmission Constraint
TRNCSIEX = Import Transmission Constraint

Note: Regions 2, 5 and 7 (ERCOT, MAPP and NPCC/New England) are excluded from economy trade; i.e. their maximum transmission constraints are set to zero.

Calculate Load (Energy) Under the Import and Export Curves

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

Allocate Capacity to Meet Demand

See discussion of the Subroutine ELALOC.

Calculate Trade Amounts Available to Replace Native Supply

TMP$CAP(IE2) = (AREANT(IE1,IE2) + AREAIT (IE1,IE2)/ETWDTH(IE2)

Where,

AREANT = Area under the original load curve
AREAIT = Area under the import load curve

Tabulate Fuel Consumption, Cost and Operations and Maintenance Costs Associated with a Set of Dispatch Decisions

See discussion of the ELCOST subroutine.

Load Nonutility Revenue Variables

See discussion of the LOADNG subroutine.

Write Out ETT Direct Access File

See discussion of the STRETT subroutine.

Store EFD Variables

See discussion of the STREFD subroutine.

Subroutine: ELMRIT

Description: This subroutine determines the merit order for dispatching by listing equipment types in order of increasing operating costs. However, before the merit order is determined, the fuel shares used by each capacity type is determined based on maximum/minimum allowed and relative fuel prices.

Called by: ELDISP

Source: uefd.f

Includes: parametr,emmparm,control,uso2grp,dispuse,dispin,dispout,dispett

Calls: ELFSHR,EMSORT

Equations:

Calculate Fuel Shares

See discussion of the ELFSHR Subroutine.

Calculate Unit Costs for Each Equipment Type

Units costs for each equipment type are calculated by first determining total costs and then factoring the total cost by the fuel shares for each capacity group.

CST_TOT = CST_OM + CST _FL + CST_SO2

Where,

CST_OM = ECOMR(I,J)
CST_FL = ZCFL*ECHTRT(I,J) * .001
CST_SO2 = PSO2 * ZSO2 *.000001 * ECHTRT(I,J) * (1.0 - REAL(KSCRB) * EFACTR)

and,

ECOMR = Variable O&M
ZCFL = UPFUEL = Delivered Fuel Prices
ECHTRT = Heat rate
PSO2 = EPSO2 = SO_2 Penalty Cost
ZSO2 = UFRSO2 = SO_2 Emission Rate
KSCRB = ECSCRB = Scrubber Efficiency

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

Sort by Unit Costs

See discussion of the EMSORT subroutine.

Subroutine: EMSORT

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

Subroutine: ELFSHR

Description: This subroutine calculate fuel shares by determining first if an equipment type is dual-fired or not. If the equipment type is dual-fired, then the cheapest fuel is used up to its maximum share, followed by the next least costly, etc., until all the capacity is allocated.

Called by: ELMRIT, ETTCOST

Source: uefd.f

Includes: parametr,ncntrl,emmparm,control,dispuse,dispin,dispout,fuelin,uefdout,uso2grp

Calls: --

Equations:

Determine Weights for Seasonal Fuel Shares

SWGHT(JSP) = EETIME(JSP)/8760 * ECCAP(I,JSP)
TWGHT = TWGHT + SWGHT(JSP)

Where,

EETIME = Number of Hours per Season
ECCAP = Conventional Capacity
I = Capacity Type
JSP = Season

SWGHT(JSP) = SWGHT(JSP) / TWGHT
FSHR = FSHR + ECFSHR(I,J)
ECFSHR(I,J) = ECFSHR(I,J) / FSHR

Where,

J = Fuel Type
ECMFSH = Maximum Fuel Share

If the Capacity is Dual-Fired, Determine Shares

First, Sort by Costs

If Prices are Close, Smooth Shares Between Fuels

If the Capacity is Dual-Fired, Use the Maximum Fuel Share for the Cheapest fuel, and adjust the Other Shares so that Total Share Equals 1

ECFSHR(I,IR(J)) = MIN(ECFSHR(I,IR(J)),FSHR)
FSHR = FSHR - ECFSHR(I,IR(J))

Subroutine: ELPLNM

Description: After the merit order has been determined, a maintenance schedule is determined for the units. This maintenance schedule is based on the seasonal reserve margin, with the maintenance scheduled from the smallest to the largest units.

Called by: ELDISP

Source Code: uefd.f

Includes: parametr,ncntrl,emmparm,control,dispuse,dispin,dispout,dispett,dispcrv

Calls: --

Equations:

Calculate Capacity Required to Meet Peak Demand in Each Time Period and Average Over All Time Periods

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

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

Where,

IMPANN = ETIMPE/TOTHRS
EXPANN = ETEXPE/TOTHRS
ETIMPE = Economy Imports (mwh)
ETEXPE = Economy Exports (mwh)
TOTHRS = Total Hours in Year
EETIME = Total Hours in Season

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

Where,

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

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

Calculate and Add in Available Hydroelectric Capacity

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

Calculate Required Capacity Utilization Lost to Planned Maintenance and Sum Total Available Capacity
If the Planned Maintenance Rate is greater than zero then:

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

Where,

ECCAP = Conventional Capacity
KPMR = Planned Maintenance Rate
EETIME = Time in Season

If the Planned Maintenance Rate is zero then:

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

Where,

ECCOPM = Capacity Net of Planned Maintenance

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

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

Determine the Maximum Reserve Margin Which Can Be Achieved

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

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

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

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

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

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

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

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

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

TOTAVL = TOTAVL - ECCOPM(IPLNT,ISP)
RQ = RQ-ECCOMP(IPLNT,ISP)

Subroutine: ELRNEW

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

Called by: ELDISP

Source Code: uefd.f

Includes: parametr,emmparm,control,dispuse,dispin,dispout,dispcrv

Calls: --

Equations:

The purpose of this section is to describe how hydroelectric and other renewable generating capacity is dispatched (operated). Hydroelectric and other renewable capacity typically has the lowest variable cost (since its fuel, water, wind, sun, etc. is considered to have no cost), which implies that it would be the first plant type placed on the curve so that its utilization is maximized. However, hydroelectric plants generally cannot be operated as baseload capacity because their output is constrained by the available water supply.

In the EFD, hydroelectric generating capacity is dispatched before other plant types in order to insure that the energy constraint is satisfied. Subsequently, the other plant types are then dispatched on the load duration curve, excluding the portion met by hydroelectric generating capacity, on a merit-order basis.

The energy constraint is incorporated using an average utilization rate for hydroelectric plants, which specifies the fraction of time water is available to operate these plants. For example, a utilization rate of 0.50 indicates that the average hours of operation, would be limited to 4,380 of the total 8,760 hours in this example. Currently, the utilization rates for hydroelectric plants are based on historical data. If regulations to protect fish by restricting water flow are enacted then these utilization rates would be adjusted downward. The total energy (S_AREA) that could be produced by the available hydroelectric capacity is given by the following equation.

<u>Determine Capacity and Energy to Remove from Load Curve</u>

The capacity of the renewable type is to be removed from the load curve unless the renewable capacity is greater than the load.

R_CAP = MIN(DBLE(EHCAP(IRNW,ISP)) * DBLE(0.001), ETHGHT(IVCT))
R_AREA = EHCAP(IRNW,ISP) * 0.001 * HOURS

S_CAP = R_CAP

Where,

EHCAP(IRNW,ISP) =Renewable Capacity
ETHGHT = Height of seasonal load duration curve
HOURS = Hours associated with renewable Capacity Factor

The model places the hydroelectric capacity using a trigger point, which indicates where on the load duration curve placement is initiated such that the energy constraint can be matched while using all of the capacity. There are three possible cases where both of these objectives can be satisfied.

- All of the capacity is used for base load (i.e. placement is entirely below the knee)

- None of the capacity is used for base load (i.e. placement is between the knee and the peak)

- Some of the capacity is used for base load (i.e. placement begins below the knee but extends above it).

The minimum amount of energy that could be generated while allocating all of the capacity (A_MIN) occurs when the capacity is placed at the top of the curve. The maximum amount that could be produced (A_MAX) results by operating the capacity at the bottom of the curve. Therefore, in order to meet the energy constraint while allocating all of the capacity, the product of the available hydroelectric capacity and the average utilization rate must be greater than or equal to A_MIN and less than or equal to A_MAX.

However, there may be some instances where it may not be possible to allocate all of the available hydroelectric capacity such that the assumed utilization rate is achieved. Consequently, the following cases are also considered in the EMM.

- The assumed utilization rate for hydroelectric plants results in generation S_AREA/R_AREA) that is less than the minimum output (A_MIN)

- The assumed utilization rate for hydroelectric plants results in generation that is greater than the maximum amount (A_MAX).

Subroutine: ELALOC

Description: This subroutine allocates the "dispatchable" capacity by capacity type for each of the seasonal load curves (defining the capacity type by a line with crosses the load duration curve and each of the segments) with the capacity dispatched by the least expensive units first. (Note the merit order of the capacity may be different across seasons because of fuel supply constraints in certain regions during certain seasons.)

Source: uefd.f

Called by: ELDISP

Includes: parametr,ncntrl,emmparm,control,dispuse,dispin,dispout,dispett

Calls: ELFACT, ELGETY, ELLOAD, ETDRAT

Equations:

First, ELALOC calculates a trigger point, i.e., the y-value after which only certain peaking units can be dispatched. Next, the capacity is allocated under the trigger point utilizing all available capacity and then peaking capacity is determined after the trigger point. Next, after the capacity has been dispatched, the area under the original load curve and the import and export load curves are determined.

<u>Initialize Capacity Bound Trigger Points (Minimum Capacity Factors for Available Capacity) and Capacity Switches</u>

Trigger Points

For Utility Units
TRIGER(3,NMTRGR)=1
TRIGER(1,NMTRGR)=I
TRIGER(2,NMTRGR)=I

For Nonutility Units
TRIGER(3,NMTRGR)=2
TRIGER(1,NMTRGR)=I
TRIGER(2,NMTRGR)=I

Where,

NMTRGR = Number of Capacity Types below the Trigger Point (The placement of the "trigger" point is based on available capacity and capacity factor lower bounds - note, both minimum and maximum capacity factors are provided)
I = Capacity Type, in increasing cost order

The x-value of the trigger point equals the minimum capacity factor for that capacity type/group (ECCFBD(JCAP,2)) {in general, this value is equal to .08 for baseload and intermediate units} while the y-value is the corresponding value on the load duration curve. This y-value signifies the point where baseload and intermediate capacity are no longer available and peak capacity is required (i.e., only peaking units can be dispatched beyond this point so the algorithm needs to check if the capacity is a baseload, intermediate or peaking unit). The subroutine ELGETY is called to determine this y value and the step number of the trigger point on the load duration curve.

CALL ELGETY(XPVPNT(MNTRGR),YVAL,IVAL) - See description of the subroutine ELGETY

Where,

XPVPNT = Maximum Capacity Factor Bounds

MNTRGR = Trigger Number
YVAL = Y value on the load duration curve
IVAL = Step number

Capacity Switch

Determines if Capacity is Available and/or the capacity factor is within range (i.e. greater than 0 and less than 1).

Order Trigger Points in Order of Increasing Load

Loop Through Trigger Points Under Capacity Line (Capacity Lines are 'Loaded' in order of increasing costs) Crosses Load Curve at Trigger Point

Check for Unallocated Capacity

Check if Capacity Can Operate at this Utilization Level

Determine Next Trigger Point which Impacts Current Capacity

Commit Capacity to Load - Call Subroutine ELLOAD
See discussion of the ELLOAD subroutine.

Update Intercept and Slope of Current Cutting Line - Call Subroutine ELDRAT
See discussion of the ELDRAT subroutine.

ESLCUT(1,IE2) = ESLCUT(1,IE2) + (SHGHT(SOLSW)*DRAT(IE2))

Where,

ESLCUT(1) = y intercept of cutting line
ESLCUT(2) = slope of the cutting line
SHGHT = Available Capacity

Store Dispatch Decision

Reduce available capacity by capacity allocated to current slice

Turn Capacity Off if All Capacity Has Been Used

Index to the Next Capacity Type in the Merit Order

Check if Total Demand Has Been Met

Resolve without Capacity Bounds (i.e., Lower Limit on baseload and intermediate units) if Demand is not Satisfied and All Capacity Has Not Been Utilized

Subroutine: ELLOAD

Description: This subroutine calculates the area under the load curve to determine generation from the capacity type chosen. In order to determine this area, the point at which the line which defines the capacity being dispatched crosses the load duration curve needs to be determined.

Source: uefd.f

Called by: ELALOC

Includes: parametr,emmparm,control,dispuse,dispin,dispout,dispett

Calls: ELDRAT

Equations:

<u>Calculate Derate Factors - Call Subroutine ELDRAT</u>
See discussion of the ELDRAT subroutine.

The slope and intercept of the cutting line are calculated as:

CUT(1,IE2) = ESLCUT(1,IE2) + (SHGHT * DRAT(IE2))

Where:

CUT(1,IE2) = intercept of cutting line

The area below the knee of the load curve is calculated and loaded into AREANT which stores data by horizontal and vertical slice. AREANT is cumulative within the vertical slice.

If CUT(1,IE) < TIYVAL(IE)
AREAIT(HN,IE) = ETWDTH(IE) + (SHGHT * DRAT(IE))
SAREA = SAREA + AREAIT(HN,IE)

Else If CUT(1,IE) < ETHGHT(IE)

If right of the crossover point: ESLUT(1,IE) > TIYVAL(IE)

AREANT(HN,IE) = ETWDTH(IE) + (SHGHT * DRAT(IE))
SAREA = SAREA + AREAIT(HN,IE)

If left of the crossover point: ELSE

AREANT(HN,IE) = ETWDTH(IE) * (CUT(1,IE) - TIYVAL(IE))
AREAIT(HN,IE) = ETWDTH(IE) * (TIYVAL(IE) - ESLCUT(1,IE))
SAREA = SAREA + AREAIT(HN,IE) + AREANT(HN,IE)

Else If CUT(1,IE) < TTYVAL(IE):
    If before the crossover point: ESLUT(1,IE) > ETHGHT(IE)

AREATT(HN,IE) = ETWDTH(IE) * (CUT(1,IE) - ETHGHT(IE))

    If left of the crossover point: ESLCUT(1,IE) > TIYVAL(IE)

AREANT(HN,IE) = ETWDTH(IE) * (CUT(1,IE) - ETHGHT(IE))
AREAIT(HN,IE) = ETWDTH(IE) * (ETHGHT(IE) - ESLCUT(1,IE))
SAREA = SAREA + AREANT(HN,IE)

If right of the crossover point: ELSE

AREATT(HN,IE) = ETWDTH(IE) * (CUT(1,IE) - ETHGHT(IE))
AREANT(HN,IE) = ETWDTH(IE) * (ETHGHT(IE) - TIYVAL(IE))
AREAIT(HN,IE) = ETWDTH(IE) * (TIYVAL(IE) - ESLCUT(1,IE))
SAREA = SAREA + AREANT(HN,IE) + AREAIT(HN,IE)

If the cutting line is above the load curve, area is calculated under the load curve from the intersection of the Y-axis to the intersection of the cutting line and the load curve, and area is added from under the cutting line from the intersection of the cutting line and the load curve to the knee. CUT(1,IE) > TTYVAL(IE):

If before the crossover point: ESLCUT(1,IE) < TIYVAL(IE)

AREATT(HN,IE) = ETWDTH(IE) * (TTYVAL(IE) - ETHGHT(IE))
AREANT(HN,IE) = ETWDTH(IE) * (ETHGHT(IE) - TIYVAL(1,IE))
AREAIT(HN,IE) = ETWDTH(IE) * (TIYVAL(IE) - ESLCUT(1,IE))
SAREA = SAREA + AREANT(HN,IE) + AREAIT(HN,IE)

If left of the crossover point: ESLCUT(1,IE) < ETHGHT(IE)

AREATT(HN,IE) = ETWDTH(IE) * (TTYVAL(IE) - ETHGHT(IE))
AREANT(HN,IE) = ETWDTH(IE) * (ETHGHT(IE) - ESLCUT(1,IE))
SAREA = SAREA + AREANT(HN,IE)

If right of the crossover point: ESLCUT(1,IE) < TTYVAL(IE)

AREATT(HN,IE) = ETWDTH(IE) * (TTYVAL(IE) - ESLCUT(IE))

Subroutine: ELGETY

Description: This subroutine evaluates a piecewise linear load duration curve to find the y value and step i for a given x coordinate (i.e., to find the y coordinate on the load curve).

Called by: ELALOC, ELRNEW

Source Code: uefd.f

Includes: parametr,emmparm,dispuse,dispin

Calls: --

Equations:

This subroutine searches amongst the x values to find the closest x value along the load curve to determine the y value and step for the x value. First, it determines the relative position of the x value to narrow the search for the x,y pair. The technique is as follows:

<u>Determine relative position of the x value</u>

TIMCUM = TIMCUM + ETWDTH(I)
XVAL(I) = TIMCUM/EETIME(ISP)

Where,

ETWDTH(I) = The x values of ordered pairs which define the load duration curve.
I = Step on the Load Curve

If the input x value is less than XVAL(I) and greater than XVAL(I-1), the y-value and step is calculated as follows:

YOUT = ETHGHT(I - 1)
IOUT = (I - 1)

Subroutine: ELDRAT

Description: This subroutine determines unit specific derate factors

Called by: ELALOC,ELLOAD

Source Code: uefd.f

Includes: parametr,emmparm,control,dispin,dispuse

Calls: --

Equations:

Drate factors are calculated:

FOR = ECFOR(IP) * EFACTR
DRAT(VLS) = FOR * (1 - (LFR * EETIME(ISP) * FAC(VLS) / ETWDTH(VLS))

Where,

ECFOR = Displaced plant group outage rate
EFACTR = Real conversion factor
LFR = Percent of year down due to load following
ETWDTH = Width of seasonal load curve
VLS = Number of points in load curve

Subroutine: ELCOST

Description: This subroutine tabulates fuel consumptions, fuel costs and O&M costs associated with a set of dispatch decisions.

Called by: ELDISP, ETTCOST

Source Code: uefd.f

Includes: parametr,emmparm,dispuse,dispin

Calls: --

Equations:

Add Plant Group Data to Running Totals

Capacity

ECAPPS(IPGRP,ISP) = ECAPPS(IPGRP,ISP) + ECDSPC(I)

Where,

ECDSPC = Capacity in Each Horizontal Slice

Generation Totals - By Season and Ownership

GEN = ECDSPE(I) * EETIME(ISP)
ETGEN = ETGEN + GEN
EQPGN(IPGRP,IFOWN) = EQPGN(IPGRP,IFOWN) + GEN
EGENPS(IPGRP,ISP) = EGENPS(IPGRP,ISP) + GEN

Where,

ECDSPE = Energy in each Horizontal Slice
I = Horizontal Slice
EETIME = Hours in Seasonal Slice
IFOWN = Ownership Type (Utility, Nonutility)
ISP = Season

Calculate Fuel Consumption, Emissions and O&M Costs

Fuel Consumption

FUEL = GEN * ECFSHR(N,IFP) * ECHTRT(N,ISP) * 0.001

GEN = Energy Generated
ECFSHR = Fuel Share
N = Plant Group
IFP = Fuel Type
ISP = Season

Total Fuel Consumption by Plant Type and by Fuel Type and Ownership

EQPFL(IPGRP) = EQPFL(IPGRP) + FUEL
EQFFL(IFLTP,IFOWN) = EQFFL(IFLTP,IFOWN) + FUEL

Aggregate Totals

This section outlines the equations for determining the aggregate totals of the dispatch decision. The following describes the totals by NERC region, plant type and ownership type (utility and nonutility). Totals by Census division and fuel supply regions and by fuel type are calculated in the same manner, only the totals are maintained by a different dimension.

Generation
UQPGENN(IPGRP,INR,IFOWN) = UQPGENN(IPGRP,INR,IFOWN) + GEN * ECFSHR(N,IFP)

Consumption
UQPCONN(IPGRP,INR,IFOWN) = UQPCONN(IPGRP,INR,IFOWN) + FUEL

Variable O&M
ERTOM(IFOWN) = ERTOM(IFOWN) + GEN * ECFSHR(N,IFP) * ECOMR(N,IFP) * 0.001

Where,

GEN = Energy
FUEL = Fuel Consumption
ECOMR = Variable O&M

SO_2 Emissions
EQPSO2(IPGRP) = EQPSO2(IPGRP) + FUEL * UFRSO2(IFLTP,IFLRG) * (1.0 - UFRASH(IFLTP,IFLRG)) * (1.0 - REAL(KSCRB) * EFACTR) * 0.5

NO_x Emissions
EQPNOX(IPGRP) = EQPNOX(IPGRP) + FUEL * NOXFAC * 0.5

CO_2 Emissions
EQPCO2(IPGRP) = EQPCO2(IPGRP) + FUEL * UFRCO2(IFLTP) * 0.5

Carbon Emissions
EQPCAR(IPGRP) = EQPCAR(IPGRP) + FUEL * UFRCAR(IFLTP) * 0.5

CO_1 Emissions
EQPCO1(IPGRP) = EQPCO1(IPGRP) + FUEL * UFRCO1(IFLTP) * 0.5

VOC Emissions
EQPVOC(IPGRP) = EQPVOC(IPGRP) + FUEL * UFRVOC(IFLTP) * 0.5

Where,

IFLTP = Fuel Type
INR = Nerc Region
UFRSO2 = SO2 Emission Rate
UFRNOX = NOx Emission Rate
UFRCO2 = CO2 Emission Rate
UFRCAR = Carbon Emission Rate
UFRCO1 = CO1 Emission Rate
UFRVOC = VOC Emission Rate
FUEL = Fuel Consumption
IFLTP = Fuel Type
KSCRB = Scrubber Efficiency

Subroutine: LOADNG

Description: This subroutine computes the revenues associated with nonutilities including exempt wholesale generators, small power producers (Renewables) and commercial, industrial and other cogenerators/facilities for the EFP.

Called by: ELDISP

Source Code: unugs.f

Includes: parametr,ncntrl,emmparm,control,dispuse,dispin,dispout,dispett,cogen,postrp

Calls: --

Equations:

Calculate Nonutility (EWG - Not Cogen) Renewable and Total Renewables (including Utilities) Total O&M Expense

HOMALL = HOMALL + ERHOM(I,J)
LOCRNW = LOCRNW + ERHOM(I,3)
EWGRNW = EWGRNW + LOCRNW

Where,
ERHOM = Variable O&M
I = Renewable Technology Type
J = Ownership Type; 1 & 2 = Utility; 3 = Nonutility
3 = Ownership Type = 3; i.e. nonutility

Calculate Total Nonutility Renewable Generation

TOTGENR = TOTGENR + EQHGN(I,3)

EQHGN = Generation
I = Renewable Technology Type
3 = Ownership Type; i.e., nonutility

Calculate Utility, Total (Utility plus nonutility) and Nonutility Variable Costs

TOTREV = TOTREV + (ERTFL(I) + ERTOM(I))
LOCEWG = LOCEWG + ERTFL(3) + ERTOM(3)
INTNCOST = INTNCOST + (ERTFL(1) + ERTFL(2) + ERTOM(1) + ERTOM(2)) + (HOMALL -EWGRNW)

Where,

ERTFL = Total Fuel Cost
ERTOM = Variable O&M
I = Ownership Type; 1 & 2 = Utility; 3 = Nonutility

Calculate EWG Revenues and Price

Total EWG Revenues are equal to the fixed plus the variable component. The fixed component (EWGFIX) is determined in the ECP where the capacity expansion decision is determined.

EWGREV = EWGFIX + LOCEWG
EWGAVP = TOTREV / TOTGEN

EWGFIX = EWG Fixed (Capital) Component

<u>Calculate Commercial Nonutility Revenues (Sold to Utilities)</u>

Calculate Generation and Capacity Sold to Utilities

TOTGENC = TOTGENC + (CSHARE(IRG,I) * (GRIDSHR(I,IYR)*(CGCOMGEN(I,IYR,J))))
TOTCAPC = TOTCAPC + (CSHARE(IRG,I) * (GRIDSHR(I,IYR)*(CGCOMCAP(I,IYR,J,K)/1000)))

Where,

CSHARE = Census to NERC regional Map
IRG = NERC Region
I = Census Division
GRIDSHR = Share of Total Sold to Utilities
CGCOMGEN = Commercial Cogeneration - Energy
CGCOMCAP = Commercial Cogeneration - Capacity
K = Vintage (Existing/Planned or Unplanned)

Commercial Revenues
LOCRCC = LOCRCC + (EWGAVP * TOTGENC) + (CGCOMPF * TOTCAPC)
EWGRCC = EWGRCC + LOCRCC

Where,

CGCOMPF = Commercial Cogen Fixed Cost

<u>Calculate Industrial and Other Nonutility Revenues</u>

Calculate Industrial and Other, Generation and Capacity Sold to Utilities

Generation
TOTGENI = TOTGENI + (UQFGENN(IFL,IRG,4))

Capacity
TOTCAPI = TOTCAPI + (ISHARE(IRG,K)*(CGINDCAP(K,IYR,I,1,L)/1000))

Add Non-traditional cogen to capacity charges
TOTGENI = TOTGENI + (ECSCAP(IDSP,IVIN,4)/1000)

Revenues
LOCRIC = LOCRIC + (EWGAVP * TOTGENI) + (CGINDPF * TOTCAPI)

Where,

ISHARE = Census to NERC region map
UQFGENN = Industrial Cogeneration (Energy)
K = Census Division
IYR = Model Year
I = Fuel Type
CGOTGEN = Generation at Other Cogen Facilities (i.e., not industrial or commercial)
CGINDCAP = Industrial Cogen Capacity

L = Vintage (Existing/Planned or Unplanned)
CGOTCAP = Other Cogen Capacity (i.e., not industrial or commercial)
CGINDPF = Industrial Fixed Component Price
CGOTPV = Other Cogen Variable Component Price
CGOTPF = Other Cogen Fixed Component Price

<u>Calculate Revenues from International Electricity Trade</u>

ETIMPD = (EWGAVP*ETIMPE)
ETEXPD = (EWGAVP*ETEXPE)

Where,

ETIMPE = International Economy Imports (mwh)
ETEXPE = International Economy Exports (mwh)

Subroutine: ELSO2N

Description: This subroutine accumulates SO2 emissions and allowances across regions for each compliance group.

Called by: ELEFD

Source: uefd.f

Incudes: parametr,emmparm,control,dispin,dispout,uso2grp

Calls: --

Equations: None

Subroutine: EMMFUEL

Description:	This subroutine checks fuel supply convergence and revises fuel prices.
Called by:	ELEFD
Source:	uefd.f
Includes:	parametr,ncntrl,emmparm,control,fuelin,dispuse
Calls:	--
Equations:	None.

Subroutine: ELSO2F

Description:	This subroutine assigns penalty cost to regional arrays.
Called by:	ELEFD
Source:	uefd.f
Includes:	parametr,emmparm,dispin,dispout,uso2grp
Calls:	--
Equations:	None

Subroutine: STROUT

Description:	This subroutine stores the results of the dispatch decision in a direct access file
Called by:	ELEFD
Source:	udaf.f
Includes:	parametr,emmparm,control,dispout
Calls:	--
Equations:	None

Subroutine: STRBLD

Description:	This subroutine stores the build decision information in a direct access file ECPIDAF.
Called by:	ELEFD
Includes:	parametr,emmparm,control,bildin
Calls:	--
Equations:	None.

Subroutine: GETOUT

Description:	This subroutine opens the direct access file OUTDAF.
Called by:	ETTCOST, ELEFD
Source Code:	udaf.f
Includes:	parametr,emmparm,control,dispout
Calls:	--
Equations:	None.

Subroutine: ETTPRC

Description: This subroutine determines economy transactions by allowing importing regions to replace their more costly generation with generation from utilities in surrounding regions. First, transmission constraints are read in from the file ETTIN and trade variables are initialized.

Called by: ELEFD

Source Code: uett.f

Includes: parametr,emmparm,control,dispett,postpr,dispuse,dispin,uettout,ncntrl

Calls: DAFRD, SORTNV, SORTEX, ETRADE, ETTCOST

Equations: This subroutine is the main calling routine of the ETT. There are no major equations in this subroutine.

Subroutine: DAFRD

Description: This subroutine reads the trade opportunities DAF file which was created in the above described EFD submodule. It then maps the sequential vertical slice index to the chronological vertical slice (creating a uniform time frame) based on group and segment numbers.

Called by: ETTPRC

Source Code: uett.f

Includes: parametr,emmparm,control,dispett,postpr,dispuse,dispin,ncntrl,dispout

Calls: GETOUT, GETETT, GETIN, GETCAN

Equations:

This subroutine loads "native" arrays with generation, capacity, and unit price information associated with native generation that could be displaced by trade. Native (import) arrays (NATIVE, CAPNV, COSTNV) are loaded if the import generation is greater than 0.

native generation (MWH): NATIVE = AREATI
native capacity (MW): CAPNV = CAPTRI
native unit price ($/mwh): COSTNV = UNTCOS

It loads "export" arrays with generation, capacity, and unit price information associated with generation available for export. Export arrays (EXAVAIL, CAPEX, COSTEX) are loaded if the export generation is greater than 0. Before loading the capacity and generation, the line loss percentage is taken out.

export generation (MWH): EXAVAIL = AREATR * (1 - LINELOSS)
export capacity (MW): CAPEX = CAPTR * (1 - LINELOSS)
export unit price ($/mwh): COSTEX = UNTCOS

It saves the region index into a variable for subsequent processing, and loads the original (1-180 version) horizontal slice reference into mapping variables (MAPIM, MAPEX) for later use.

The data are then sorted by costs.

Subroutine: GETCAN

Description:	This subroutine reads ETTCN file (Canadian transmission).
Called by:	DAFRD
Source Code:	udaf.f
Includes:	parametr,emmparm,control,dispett
Calls:	None
Equations:	None

Subroutine: GETETT

Description:	This subroutine captures the area available for displacement and the area available for exports by region, season, and vertical and horizontal slice from ETTDF file.
Called by:	DAFRD
Source Code:	udaf.f
Includes:	parametr,emmparm,control,dispett
Calls:	--
Equations:	None

Subroutine: SORTNV

Description: This subroutine sorts native (the importing region's) supply in decreasing order; i.e. an importing region wants to replace its most expensive supply with the cheapest alternative available. This 'ordering' is achieved through creating an index (pointer) to the cost arrays which reflects the decreasing costs. This indexing is done in the subroutine INDEXD.

Called by: ETTPRC

Source Code: uett.f

Includes: parametr,emmparm,control,postpr

Calls: INDEXD

Equations: None

Subroutine: INDEXD

Description:	This subroutine creates an index to an array reflecting the values of the array in decreasing order.
Called by:	SORTNV
Source Code:	uett.f
Includes:	--
Calls:	--
Equations:	None

Subroutine: SORTEX

Description: This subroutine sorts the exporting region's supply in increasing order; i.e. an exporting region will sell capacity which is the lowest cost to maximize profits. This 'ordering' is achieved through creating an index (pointer) to the cost arrays which reflects the increasing costs. This indexing is done in the subroutine INDEXI.

Called by: ETTPRC

Source Code: uett.f

Includes: parametr,emmparm,control,postpr

Calls: INDEXI

Equations: None

Subroutine: INDEXI

Description:	This subroutine creates an index to an array reflecting the values of the array in increasing order for the export curve; i.e, the least expensive energy will be sold first.
Called by:	SORTEX
Source Code:	UETT
Includes:	--
Calls:	--
Equations:	None

Subroutine: ETRADE

Description: This subroutine determines the best trade among the regions by comparing the relative costs in each vertical slice. This subroutine calls the subroutine QUALFY to insure that the region's about to engage in trade are in fact 'trading partners' (i.e. allowed to trade based on historical relationships, physical locations and additional constraints currently imposed on the model during this time) and to check if transmission capability is available.

Called by: ETTPRC

Source Code: uett.f

Includes: parametr,ncntrl,emmparm,control,dispett,postpr,dispuse,uettout

Calls: QUALFY

Equations: For each native capacity and generation amount, all the export capacity and generation that is available in the same vertical slice (seasonal and time of day time period) is considered for a potential trade. In order for trade to occur, the following conditions must be met:

- The cost of buying from another region must be less than the cost of producing at home. COSTEX < COSTNV
- The difference between the native cost and the export cost must be greater than the price threshold.
- The potential export region must be one that can physically trade with the import region. (This is determined by looking up the records in the Constraints File.)
- If the 2 regions are trading regions, there must also be room in the pipeline (i.e. all the constraint values not used up yet by contracts).

The first 2 of these are determined in ETRADE. The latter 2 are determined by calling the subroutine QUALFY.

Once the trade algorithm is complete, the generation and capacity amounts traded are loaded into arrays so that generation that will be displaced by trade is subtracted out of the DISPOUT arrays and so that generation that is produced for export is added to DISPOUT arrays.

Displaced generation arrays:

ETCAPO = TEMPC
ETGENO = TEMPG
ETCSTO = COSTNV * TEMPG

Arrays associated with generation produced for export:

ETCAPN = TEMPC / (1 - LINELOSS)
ETGENN = TEMPG / (1 - LINELOSS)
ETCSTN = COSTEX * (TEMPG / (1 - LINELOSS))

Where,

TEMPC = the capacity (MW) that is being traded
TEMPG = the generation (MWH) that is being traded

Note: Generation and capacity have been scaled back up by the line loss factor.

Next the report writer variables for the export region are calculated as follows:

ZTDMDE = ZTDMDE + (COSTEX * (TEMPG / (1 -LINELOSS))) / 1000

ZTDMPE = ZTDMPE + (((COSTNV - COSTEX) * 0.5) *
    (TEMPG / (1 - LINELOSS))) / 1000

ZTDMME = ZTDMME + TEMPG / (1 - LINELOSS)

Where,

TEMPG = the generation being traded
ZTDMDE = Domestic economy sales (MM$)
ZTDMPE = Domestic economy profit (MM$)
ZTDMME = Domestic economy generation (Gwh)

The report writer variables for the import region are calculated as follows:

Import revenues:

ETFLPI = ETFLPI + (COSTEX + (COSTNV - COSTEX) * 0.5) +
    (TEMPG / (1 - LINELOSS))

ZTDMDE = ZTDMDE - ETFLPI / 1000
ZTDMME = ZTDMME - TRANSGEN

ZTDMPE = ZTDMPE - ((COSTNV * (TRANSGEN / (1 - LINELOSS)) - ETFLPI)) / 1000

Where,

TRANSGEN = total generation being imported in a particular trade transaction

Subroutine: QUALFY

Description:	This subroutine checks to make sure the region's engaging in trade are linked and within transmission constraints.
Called by:	ETRADE
Source Code:	uett.f
Includes:	parametr,emmparm,postpr,dispett,dispin,control,ncntrl
Calls:	--
Equations:	None

Subroutine: ETTCOST

Description: This subroutine modifies the results of the original dispatch decision (generations, consumption and revenues), unique trade results are also stored.

Called by: ETTPRC

Source Code: uett.f

Includes: parametr,ncntrl,emmparm,control,dispin,bildin,ecpcntl,dispout,dispuse,fuelin,dispett,postpr,uettout,dispinyr,qblk

Calls: GETOUT, GETBLD, GETIN, ELFSHR, STROUT, STRBLD,GETEIJ, ELCOST

Equations:

The subroutine begins by reading in the old ELCOST results from DISPOUT DAF file (by calling GETOUT). Next capacity and generation that was traded is calculated.

ECDSPC = ETCAPN - ETCAPO
ECDSPE = ETGENN - ETGENO

DISPOUT variables are modified (generation, consumption, revenues) for the trade, and the unique trade variables are loaded with summary results.

ETDMDE = -ZTDMDE
ETDMME = -ZTDMME
ETDMPE = -ZTDMPE
ETDMDF = -ZTDMDF
ETDMMF = -ZTDMMF / 1000
ETIMPD = ZTIMPD
ETEXPD = ZTEXPD
ETIMPF = ZTIMPF / 1000
ETEXPF = ZTEXPF / 1000

Note:

a) scale changes in ZTDMMF, ZTIMPF, and ZTEXPF (to Thous. Mwh)
b) sign changes for ZTDMDE, ZTDMME, ZTDMPE ZTDMDF, and ZTDMMF (to net exports)

Subroutine: GETEIJ

Description:	This subroutine reads ETTDM electricity transmission information DAF.
Called by:	ETTCOST
Source Code:	udaf.f
Includes:	parametr,emmparm,control,dispett
Calls:	--
Equations:	None

Subroutine: STRSO2

Description: This subroutine saves information temporarily stored in the common block USO2GRP in a file, in particular, the total SO_2 produced, the penalty cost, and the SO_2 allowances.

Called by: ELEFD

Source: udaf.f

Includes: parametr,emmparm,control,uso2grp

Calls: --

Equations: None

Subroutine: STREFD

Description:	This subroutine saves resulting information from the solution of the EFD into the EFDOUT DAF.
Called by:	ELDISP
Source:	udaf.f
Includes:	parametr,emmparm,control,dispett
Calls:	--
Equations:	None

Subroutine: STRETT

Description:	This subroutine stores the resulting information from the solution of the ETT (area available for displacement and the area available for exports by region, season, and vertical and horizontal slice) into the ETTDAF.
Called by:	ELDISP
Source:	udaf.f
Includes:	parametr,emmparm,control,dispett
Calls:	--
Equations:	None

Appendix C

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December 1991.

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Appendix D

D.1 Summary of Title IV to the Clean Air Act Amendments of 1990

Unlike the previous New Source Performance Standards (NSPS) and Revised New Source Performance Standards (RNSPS) programs which set plant and unit specific emission rate limits, the CAAA program employs a unique, market-based approach to SO_2 emission reductions, while relying on more traditional methods for NO_x reductions. Under the market-based approach, utilities receive a limited number of marketable emission permits or “allowances” each year.[23] Each allowance permits the emission of 1 ton of SO_2 for that year or any year thereafter. In the EMM-NEMS these SO_2 allowances are treated as emission constraints on utility and nonutility planning and operations.

The acid deposition provisions of the CAAA are instituted in two phases. In Phase I, 1995 through 1999, allowances are allocated to large, electric-utility steam generating units fired by fossil fuels in an effort to limit their average SO_2 emissions to 2.5 pounds per million Btu of heat input.[24] No additional control is required at other units.

In Phase II, beginning in 2000, “basic” allowances are allocated to all electric-utility steam units greater than 25 megawatts in existence between 1985 and 1995.[25] New utility and nonutility units that begin operating after 1995 are required to have allowances beginning in 2000, which they must acquire through the market or in some other manner. In general, the amount of allowances allocated to a particular unit is determined by its size, primary fuel, 1985 emission rate, average fuel consumption from 1985 through 1987, and the year it began operation. The annual “basic” allowance allocation is limited to 8.95 million tons. In addition, almost 0.5 million “bonus” allowances are distributed each year for the first 10 years of Phase II.

In both phases, 2.8 percent of the “basic” allowances intended to be allocated each year will be placed in a special reserve, a portion of which may be sold directly, the remainder to be auctioned. The auction is intended to stimulate the market and to give new entrants, such as independent power producers, access to allowances. The direct sale is intended to be a market of last resort for anyone needing but unable to acquire allowances. Proceeds from both the auction and the direct sale are returned to the original owners of the allowances. These auctions and direct sales of allowances are not explicitly represented in the EMM-NEMS because of their small impact on the allowance market. However, they are included in the original allocation of allowances, and, thus captured in trading.

The CAAA establishes incentives (e.g., extra allowances and compliance-deadline extensions) for installing scrubbers during Phase I, instituting energy conservation, using new renewable energy sources, and using clean coal technologies. Presently the Environmental Protection Agency is finalizing procedures for a utility to take advantage of these incentives. When these procedures are finalized the EMM-NEMS allowance constraints will be modified to reflect the distribution of these incentive allowances.

Allowances can also be banked (saved) for future use. Because fewer emissions are allowed after 1999, allowances will increase in value beginning in 2000. A utility may find it advantageous to overcomply from 1995 through 1999, saving allowances for use in Phase II. Because banking decisions are dependent on unit and utility specific information (including each utility's assumptions about future allowance costs), banking algorithms is not endogenized within EMM-NEMS. Analysis will be done exogenous to the model to access the economics of banking and the EMM-NEMS allowances constraints will be adjusted to reflect the estimated levels of banking in future versions of NEMS.

Utilities must also submit compliance plans for and install continuous emission-monitoring devices at all affected units. A utility that does not comply (emits SO_2 in excess of the allowances it holds) must pay $2,000 for each ton of SO_2 it emits in excess of its allowances and must offset those emissions the following year.

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[23]Electricity generators must still meet the emission standards in existence before the passage of the CAAA.

[24]Phase I affects electric utility steam generating units with a nameplate capacity of 100 megawatts or greater and an actual 1985 SO_2 emission rate of 2.5 pounds per million Btu or greater. The names of the units and their Phase I allowances are listed in the CAAA.

[25]Units less than or equal to 25 megawatts, combustion turbines, solar units, wind turbines, geothermal units, and hydroelectric units are not subject to the requirements of the CAAA.

The CAAA also requires the Environmental Protection Agency (EPA) to set new NO_x emission standards for existing and new utility boilers. For existing tangentially-fired boilers[26] the maximum emission rate the EPA can set is 0.45 pounds of NO_x per million Btu of heat input; for existing dry-bottom wall-fired boilers[27] (excluding cell-burner technology[28]) the maximum is 0.50 pounds per million Btu. These new standards must be met by 1995. For cyclones,[29] wet-bottom wall-fired boilers,[30] cell-burner technology, and other utility boilers, the EPA has until 1997 to set new standards, taking into account available technology and environmental considerations. In addition, by 1993, the EPA must revise the performance standards for NO_x emissions from new units to account for improved emission-reduction methods since the 1979 revision.

The SO_2 emission allowance program established in the CAAA offer a more economical approach to emissions control compared with the NSPS and RNSPS programs established in the original Clean Air Act and its earlier amendments. By establishing a market for emission permits, utilities with relatively high cost emissions reduction options will be able to purchase allowances from other utilities with lower cost options. These allowance trades among utilities are expected to continue until there are no gains or savings to be made, resulting in the most cost-effective solution.

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[26] Tangentially-fired boilers are fired from the corners of the furnace; the fireball can be directed upward or downward.

[27] Wall-fired boilers have burners mounted on their front and back walls. Dry-bottom wall-fired boilers use coal with high ash-fusion temperatures. Most of the fly ash is removed just ahead of the stack.

[28] Cell-burner technology is used in dry-bottom wall-fired boilers. The burners are arranged in clusters on the firing wall to reduce NO_x emissions.

[29] In a cyclone boiler, combustion occurs in water-cooled horizontal cylinders connected to the furnace walls. High-velocity air is fed tangentially to the cylinders, and the combustion gases exit into the furnace.

[30] Wet-bottom wall-fired boilers use coal with low-ash fusion temperatures, where the slag tends to cling to the walls and bottom of the furnace. In a wet-bottom furnace, the slag drops into a tank of water.

Appendix E

E.1 Model Abstract

Description: The Electricity Fuel Dispatch (EFD) determines the yearly operation of the electric power industry. The EFD uses merit order dispatching, meaning that plants (excluding intermittent, renewable technologies and cogenerators) are dispatched until demand is satisfied based on their operation costs, with least-cost plants being operated first. Emissions of pollutants (such as sulfur dioxide, nitrogen oxides and carbon dioxide) from generating units are also accounted for during dispatching as are emission allowances. During off-peak periods, the EFD institutes load following, which is the practice of running plants near their minimum operating levels rather than shutting them down and incurring shut-off and start-up costs. In addition, to account for scheduled and unscheduled maintenance, the capacity of each plant is derated (lowered) to the expected availability level. Finally, the EMM-NEMS simulates the operation of utility and nonutility (excluding cogenerators) plants for each region on a seasonal basis to reflect the seasonal variation in electricity demand.

Last Model Update: December 1996

Part of Another Model?: Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)

Model Interfaces: The EFD interfaces with other components of the EMM and NEMS. Electricity demand, available capacity and fuel costs are provided by the Load and Demand Side Management Submodule, the Electricity Capacity Planning Submodule (ECP), and the Fuel Supply Modules, respectively. In turn, the EFD provides the Electricity Finance and Pricing (EFP), the Fuel Supply, Renewables and Systems Modules the resulting operating expenses, generation, fuel use and emissions.

Sponsor:

- **Office:** Office of Integrated Analysis and Forecasting
- **Division:** Energy Supply and Conversion Division
- **Branch:** Nuclear and Electricity Analysis Branch, EI-821
- **Model Contact:** Melinda Hobbs
- **Telephone:** (202) 586-0012

Archive Media and Installation Manuals(s): The EFD is archived as part of the NEMS system. The installation handbook and tape information can be obtained from the National Energy Information Center at (202) 586-8800.

Non-DOE Input Sources:

North American Electric Reliability Council

- Hourly load data

Environmental Protection Agency

- Emissions allowances for sulfur dioxide

DOE Data Input Sources:

Energy Information Administration, Cost and Performance Database

- Fixed Operations and Maintenance
- Variable Operations and Maintenance
- Planned Outages
- Forced Outages

- Heat Rate
- Operating Profile (Percent of Available Hours at Indicated Load Levels)
- Maximum Capacity Factor (percent)
- Maximum Availability Hours (hours)
- Duty Cycle
- Scrubber SO_2 Removal Efficiency
- Retrofit Factor
- Particulate Removal Efficiency
- Sludge Disposal Costs
- Fly and Bottom Ash Disposal Costs

On Location, Inc., Deliverable 6, *Draft Data Inputs for Implementation of ETT, Task 92086, Contract DE-AC01-88EI21033*, memorandum from Less Goudarzi/Joanne Shore to Pat Toner, Energy Information Administration, March 5, 1993.

- Transmission flow constraints
- Transmission capacity expenditure coefficients
- Transmission losses

Federal Energy Regulatory Commission, Form FERC-1, "Annual Report of Major Electric Utilities, Licensees and Others"

- Transmission Operations and Maintenance Data

International Affairs and Energy Emergencies, Form IE-411, "Coordinated Regional Bulk Power Supply Program Report"

- Existing and Planned Interregional and International Transfers
- Fuel Cost Adjustment for Purchased Power
- Adjustment to Revenues for Bulk Power Sales

Energy Information Administration, Form EIA-759, "Monthly Power Plant Report"

- Maximum fuel shares for existing capacity

Energy Information Administration, Office of Integrated Analysis and Forecasting

- Nuclear Maximum Capacity Factors
- Annual Fuel Costs
- International Economy Transactions

Energy Information Administration, *Electric Power Annual 1995*, (DOE/EIA-0349(96)), draft report, 1996.

- Historic (1990-1995) utility and nonutility generation and fuel consumption data by fuel
- Historic Emissions

Energy Information Administration, Form EIA-860, "Annual Electric Generator Report"

- Existing Utility Capacity
- Heat rates for existing capacity
- Planned utility capacity additions
- Planned utility capacity retirements

Energy Information Administration, 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

Energy Information Administration, Form-767, "Steam-Electric Plant Operation and Design Report"

- Emission rates for existing generating units
- Pollution control equipment installed at existing generating units

Energy Information Administration, Office of Integrated Analysis and Forecasting

- Maximum Nuclear Capacity Factors
- Annual Nuclear Fuel Costs
- International Economy Transactions

General Output Descriptions: The EFD provides electricity generation, fuel consumption at electric utilities, variable cost and emissions information to various components of the EMM and NEMS. This information is used to compute electricity prices (in the Electricity Finance and Pricing Submodule), to determine fuel prices (in the Fuel Supply Modules) and to account for emissions in the Systems Module.

Computing Environment:

- **Hardware Used:** IBM RSC 6000
- **Operating System:** UNIX
- **Language/Software Used:** FORTRAN 77
- **Memory Requirement:** 16,000K (All EMM)
- **Storage Requirement:** 6,075K (All EMM)
- **Estimates Run Time:** 10 CPU seconds per iteration per year

Independent Expert Reviews Conducted:

- Roger Naill, AES, National Energy Modeling System Conference, February 1 and 2, 1993.
- Vance Mullis, Southern Company Services, National Energy Modeling System Conference, February 1 and 2, 1993.
- Larry Makovich, DRI, McGraw-Hill, National Energy Modeling System Conference, February 1 and 2, 1993.

Appendix F

F.1 Data Quality and Estimation

This section describes the quality of the data used in the EFD and the estimation techniques used to prepare the data for use in the model.

Exogenous Inputs

Sulfur Dioxide, Nitrogen Oxide, and Carbon Dioxide Emission Factors

See the Electric Power Annual 1991, (DOE/EIA-0348(93)), January 1993, for a description of the methodology and the data sources used to determine these factors.

Transmission Constraints

Transmission constraints were obtained from the April 1992 NERC regional publications of the Coordinated Bulk Power Supply Program Report (DOE Form OE-411). This report contains the bulk power supply plans for utilities over the next decade; in particular, the first order contingency plan for utilities, which is the measure for transmission capacity used as input to NEMS. This measure was used since most transmission networks are designed and operated on this basis. First order contingency planning entails operating and designing the system so that any one component can fail or be removed from service without causing the remaining facilities in service to be overloaded. This measure of transmission capability is conservative but necessary to ensure reliability yet consistent with normal utility operations.

Interregional Transmission Losses

Form EIA-861 data were used to explore national average line losses to points of resale versus end-use customers. The data does not provide this information directly. The data contains total losses, sales to ultimate customer and sales for resale. A regression was run over the 1990 and 1991 data to estimate a and b as follows:

$$L = aQ + bS$$

Where:	L	=	Total Losses
	Q	=	Ultimate Customer Sales
	S	=	Sales for Resale
	a	=	Percent losses associated with ultimate customer sales
	b	=	Percent losses associated with sales for resale

Theoretically, wheeling and gross exchanges should be included, but the data were not readily available, and the purpose of this calculation was to determine a rough magnitude for transmission losses, as represented by the loss factor associated with sales for resale. The transmission losses were 1.8 percent in 1990 and 2.4 percent in 1991, on average. A more detailed summary of the results follows:

1990 data:

Standard Error of Y Estimate	115.1536		
a	0.07309	T-value	159.1525
b	0.01822	T-value	20.74191
R Squared	90.2 percent		

1991 data:

Standard Error of Y Estimate	92.9042		
a	0.07099	T-value	192.1416

b	0.02395	T-value	35.23035
R Squared	93.6 percent		

In future versions of NEMS, refinement of this calculation will be considered.

(Source: Memorandum from Less Goudarzi and Joanne Shore, OnLocation Inc., to Pat Toner, dated March 5, 1993, Deliverable 6, "Draft Data Inputs for Implementation of ETT, Task 92086, Contract DE-AC01-88EI21033".)

Intraregional Transmission and Distribution Loss Factor

The transmission and distribution loss factor for each electricity supply region was derived using the following equation:

$$\text{Losses} = ((\text{Net Energy for Load/Sales}) - 1) * 100$$

Note: 1990 data were used.

Source: Memorandum from Less Goudarzi, Dana Griswold, and Laura Train, OnLocation Inc., to Pat Toner, dated July 30, 1993, Deliverable 2, "ETT Data Inputs Deliverable Subtask 93108, Contract DE-AC01-89EI21033".)

Firm Power Trade Contracts

Data were obtained from the April 1992 NERC regional publications of the Coordinated Bulk Power Supply Program Report (DOE Form OE-411). This report contains estimates for the next 10 years. These contracts reflect individual utility's estimates of future firm power trades. In some instances, there were discrepancies between the reporting of the purchasing and the selling utility (for example, there are two trading trading partners, A and B, and A sells capacity to B. A reports that it will sell 50 megawatts to B while B reports that it plans to purchase 75 megawatts from A), analyst judgement was used to determine the contracted trade. In general, the larger reported value was used. Data for post 2001 are not available so existing contracts in 2001 were assumed to continue through 2010. This assumption will remain until further information is available.

Load Data

Load shapes were determined using historic load data obtained from NERC. This regional (NERC region and subregion) load information is the aggregation of individual utility load data.

Economy Trade Thresholds

There is currently an assumed minimum price threshold (i.e., difference between the purchasing and selling utilities cost) of 1 mill per kilowatthour for economy trade to occur. This is based on the assumption that there must be an economic *incentive* to trade. If the costs are the same between the purchasing and selling utilities, there is not an incentive to trade.

Inputs from Other Modules

Available Generating Capacity by Plant Type - Utility and Nonutility

The existing and planned capacity and performance for utilities and nonutilities is as reported on the EIA Forms 860, "Annual Electric Generator Report" and the EIA Form 867, "Annual Nonutility Power Producer Report", respectively. These forms contain the universe for utility and nonutility units. The "universe" of nonutility projects lags a year because the forms are sent to nonutility power producers which report sales to utilities on the EIA Form 860. Unplanned capacity additions result from the decision-making process in the ECP which is based on cost and performance characteristics from the Energy Information Administrations Cost and Performance database. See the ECP documentation for a description of the data quality and estimation methods used in its model inputs.

Renewable Generation by Fuel Type

See the *Renewable Fuels Module Documentation*.

Demand by Sector

See the *Commercial, Industrial, Residential and Transportation Models Documentation.*

Fossil Fuel Prices, SO2 Emissions

See the *Coal Supply*, and *Oil and Gas Supply Models Documentation.*