Documentation

Electricity Fuel Dispatch

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1. Introduction

1.1 Purpose of the Report

This report documents the objectives, analytical approach and development of the National Energy Modeling System Electricity Fuel Dispatch Submodule (EFD), a submodule of the Electricity Market Module (EMM). 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 for which energy analysts can undertake model enhancements, data updates and parameter refinements as future projects. Last, because the major use of the EFD is to develop forecasts for EIA's *Annual Energy Outlook*, this documentation explains the calculations and major inputs and assumptions which were used to generate this forecast.

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.) The utilities have the option to purchase or sell energy to neighboring regions if it is economic.

Fuel consumption and emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x) and carbon are determined based on the utilization of capacity. Fuel consumption is provided to the fuel supply modules while fuel and variable operations and maintenance (O&M) costs are used to determine electricity prices in the Electricity Finance and Pricing (EFP) Submodule. Electricity prices are provided to the demand models to determine electricity demand.
Although the EFD is similar to its predecessor in the EMM-IFFS,[1] there has been significant improvement in the NEMS. The most significant improvement is the endogenous representation of the Clean Air Act Amendments

(CAAA)[2]. The segmentation and the maintenance of seasonality in the load duration curves (to better represent the demand for electricity and maintenance scheduling and fuel availability, and to account for trade) has also greatly

[1]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, D.C., May 1987), the Energy Information Administration, *Model Documentation: Electricity Market Module*, DOE/EIA-MOO2 (Washington, DC, December 1984).

[2]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.

enhanced the capability of the model. In IFFS, the strategies employed by utilities to comply with the CAAA were represented in the National Coal Model (NCM), which was not integrated in IFFS.[3] The NCM was provided electricity demand and fuel prices from an appropriate IFFS run and in turn provided to the EMM-IFFS revised fuel mixes and the cost and quantity of equipment installed to achieve the emissions reductions. The EMM-IFFS would then re-run with these new costs and fuel mixes. If the run resulted in different electricity demands and fuel prices, the cycle would be repeated using the new IFFS runs. This process continued until the results of the two models were closely calibrated. The exogenous representation of the CAAA in IFFS resulted in a time-consuming and awkward process.

The segmentation of the load duration curve and the maintenance of chronology in the load duration curve (the load duration curve is divided into 26 segments) allows for better representation of electricity demand, trade and demand side management.

Another enhancement is the representation of electricity supply by North American Electric Reliability Council (NERC) regions and subregions in place of 10 Federal Regions. Using NERC regions and subregions (referred to in this report as NEMS electricity supply regions) allows a better representation of electricity markets and the operations of electric utilities. Load data for electric utilities is collected by the NERC and is provided at the NERC regional level. NERC level forecasts also allow for comparison of EIA and NERC forecasts at the regional level.

The EFD also represents nonutility (excluding cogenerators) supply and interregional economy sales endogenously.[4] 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 dispatchs nonutility supply together with utility fossil-fueled and nuclear generating capacity. In EMM-IFFS, generation from these sources was determined exogenously and demand was adjusted by their generation. 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. In IFFS, bulk power transactions were determined exogenously, based on historic interregional relationships.

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 3 also reviews alternative dispatching and interregional trade modeling methodologies drawn from existing literature, providing a comparison to the chosen approach. 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 and parameter files currently residing on the EIA mainframe. 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.

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[3]The NCM could not be incorporated within the IFFS framework because of its size and execution time and because it would be too difficult to extract only the dispatching structure from the model. For a detailed description of the NCM, see Energy Information Administration, *National Coal Model: Executive Summary*, DOE/EIA-0325 (Washington, DC, April 1982).

[4]In future development of NEMS, renewable supply, demand side management programs and international economy trade will be represented endogenously. DSM impacts will be incorporated by adjusting the demand for capacity prior to the dispatching decision, i.e. the load curve will be revised.

Volume II of this report documents technical detail on model data and equations. Volume II also provides sensitivity analysis and scenario output in support of the documentation of model performance and will be available in December 1994.

Insert Figure 1 here

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 for inclusion in the Energy Information Administration's *Annual Energy Outlook.*

The EFD addresses utility and nonutility supplies endogenously; i.e. the EFD dispatches nonutility sources[5] together with utility fossil-fuel and nuclear generating capacity. However, cogeneration and intermittent renewable technologies are represented exogenously with the load curve adjusted prior to dispatching.

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

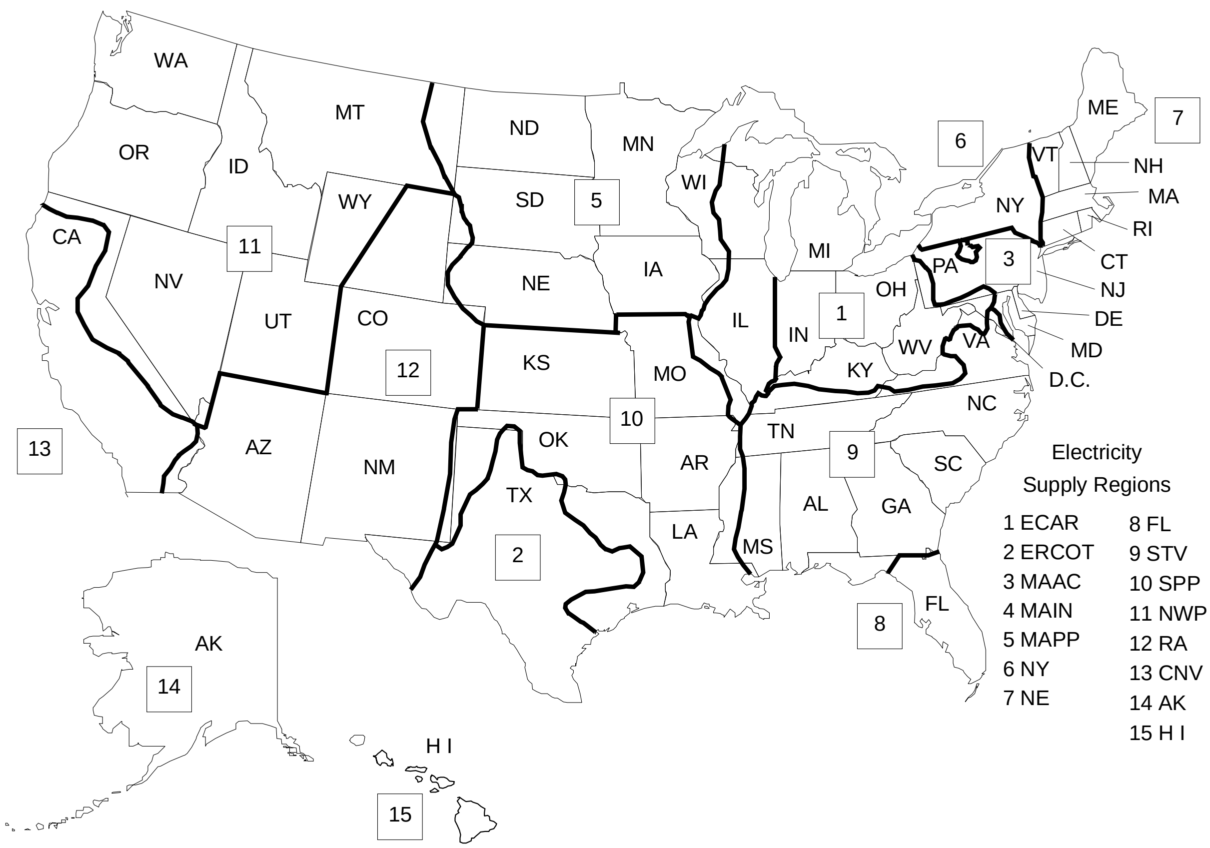
NERC Region/ Subregion	Acronym
East Central Areal Reliability Coordination Agreement	ECAR
Electric Reliability Council of Texas	ERCOT
Mid-Atlantic Area Council	MAAC
Mid-America Interconnected Network	MAIN
Mid-Continent Area Power Pool	MAPP
Northeast Power Coordinating Council/New England	NPCC/NE
Northeast 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 incorporates current regulations, including the Clean Air Act Amendments of 1990 (CAAA). The EFD only incorporates strategies that can be implemented during dispatching, fuel switching and allowance trading (i.e. strategies for reducing SO_2 and NO_x emissions such as retrofitting units with scrubbers and low NO_x burners are represented in the ECP). Allowance trading is represented by adding a penalty cost for each ton of SO_2 emitted. (Note: In the first year and iteration of the model, the penalty cost is set to zero, as if there were no penalty for polluting). If the resulting dispatch decision results in emissions which are above the regulated limit, than the dispatch decision is re-done, with a higher penalty cost. Likewise, if the resulting dispatch decision results in emissions which are below the regulated limit, the dispatch is re-done, with a lower penalty cost. This procedure is repeated until equilibrium it met.

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

Another feature of the EFD is the ability of certain regions to engage in interregional economy transactions. In the EFD, after the original dispatch decision has been completed, certain regions are allowed to purchase surplus, more economic power from neighboring regions.[6] Again, this dispatch decision is subject to CAAA limits.

Figure 1NEMS 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 and output files, the sources for exogenous data, and an inventory of data flows among modules is presented in Appendix A. Table 2 contains an overview of the input, output and work files for the EFD, along with a reference to the file descriptions contained in Appendix A.

2.2.1 Exogenous Inputs

[6]Currently, 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 in these regions and as time and resources allow.

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 provided by the Argonne National Laboratories Cost and Performance Database for New and Existing Generating Technologies. Transmission constraints and trade relationships[7] are also input to incorporate economy trade.

SO_2, 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

The demand modules provide electricity demand by sector. These demands are aggregated and mapped to a load duration curve in the EMM prior to the dispatch decision. In future versions of NEMS, the Load and Demand Side Management Submodule will be responsible for mapping demand to the load duration curve.

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. In future versions of NEMS, this capacity will be mapped to the appropriate slices of the load curve in the Load and Demand Side Management Submodule. 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. These prices are used in determining variable costs for each plant type and arranging the plants in merit order.

The Electricity Capacity Planning (ECP) Submodules 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 subject to environmental restrictions. 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. Emissions are provided to the integrating module.

Output reports provide projections of generation and fuel consumption by plant and fuel type, for both utilities and

[7] The transmission links tell the dispatch submodule that the region's have the ability to trade with each other.

Table 2 Summary of Data Flows in the EFD

Exogenous Inputs

Table File/Reference	Table Common/Reference	General Description
None	EMM$PARM/Table A-1	EMM Parameters
None	PARAMETR/Table A-2	NEMS Parameters
None	ECP$CNTL/Table A-3	Control/Switch File
None	NCNTRL/Table A-4	Control/Switch File
LOADDAF	LOADIN/Table A-5	Load shape information (EFD & ECP)
PLNTDAF	PLNTIN/Table A-6	Plant level information (Existing, planned and unplanned)
FUELDAF	FUELIN/Table A-7	Emission rates
ETTIN/Table A-8	Local	Constraints File
ETTDEM/Table A-9	DISPETT/Table A-10	Net Flows, Canadian Supply Curve Info. Predominantly for ECP
NUGPIPE/Table A-11	Local	'Other' cogen (not industrial/commercial)
SO2CNTL	USO2GRP/Table A-12	# of Compliance Groups, Tolerances, and Price Jumps
ELGNCR/Table A-13	EL$SHRS/Table A-13	Data to Map Demand from Census to NERC region
ELDATYR/Table A-14	DISPINYR/Table A-15	Historical Data Overwrites
INPTDAF	DISPIN/Table A-16	Overall input. Read from DAF for each region & year

Inputs from Other Modules

Module(s)	Table Common/Reference	General Description
Industrial & Commercial	COGEN/Table A-17	Cogeneration capacity to be removed from load curve
RFM	WRENEW/Table A-18	Renewables cost and performance info.
Fuel Supply	FUELIN/Table A-6	Fuel prices
Various	CONTROL/Table A-19	Electricity Demand

Output/Work Files

File	Table Common/Reference	General Description
ETT$TMP/Table A-20	DISPETT/Table A-11	Updated ETTDEM file (with model result info)
None	DISPUSE/Table A-21	EFD working space
OUTDAF/Table A-22	DISPOUT	Results of the EFD Decision One region, current year (Generation, Consumption & Emissions)
None	UEFDOUT/Table A-23	Same as DISPOUT but for all regions and years (Reporting Purposes)
None	UETTOUT/Table A-24	Trade Results

Note: The input/output files for the EMM have the following naming convention - &6005PRJ.UTIL.<name2>. <scenario>.<datekey>. The common block (Column 2 of Table 2) refers to the member of the partitioned data set &6005PRJ.NEMS.COMMON.PDS.D1123931

nonutilities and interregional and international economy trade.[8] Reports include emissions. These reports contain both national and regional projections. National projections are published in the *Annual Energy Outlook 1994* and regional projections are published in the *Supplement to the Annual Energy Outlook 1994*. Appendix A contains sample outputs from actual model runs and a description of the files and common blocks where this information is stored.

[8]In future versions of NEMS, the information needed to graph the solution of the EFD will be saved in the variables stored in the DISPCRV common block (CN6005PRJ.NEMS.COMMON.PDS. D1123931:DISPCRV). Currently, nothing is saved in this common block. Nevertheless, a copy of the common block is included in Appendix A.

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 up and running 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.[9] 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 reduces emissions to 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, a penalty cost for emitting

[9] 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.

Insert LDC and load curve here!

SO_2 is added to units which emit SO_2 (in the first iteration, the penalty cost is set to zero). Next, capacity to be dispatched is ranked from least to most costly.[10] 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 and the emissions from the dispatch decision need to fall below the limits imposed by the CAAA). Next, generation is 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. Economy trade is then performed. Fuel consumption and emissions are determined as a function of generation. Last, national SO_2 emissions are computed and examined to see if they are within the CAAA limits. The solution to the dispatch algorithm is achieved by iterating this process to find the smallest penalty cost that satisfied the emissions restriction.

3.2 Fundamental Assumptions

The fundamental assumptions of the EFD include endogenizing 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 involves 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 both intrafuel and interfuel switching. For example, required reductions in SO_2 emissions can be accomplished in coal-fired or oil-fired units by using the same fuel type with a lower sulfur content. Another option is to decrease utilization of these fossil-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. This emissions trading is represented via a penalty cost function which is discussed briefly in the "Theoretical Approach" outlined previously and in further detail in Appendix B.

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 causes the EFD to over-optimized because

[10] Note, cogeneration and renewables (excluding hydroelectric) are not currently dispatched in the EFD. Their capacity is removed from the load duration curve prior to the dispatch decision. Likewise, international economy trade is not currently represented in the EFD. It will be incorporated in the decision-making framework in future versions of NEMS.

transmission and other engineering constraints are not represented. Also, intraregional 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; i.e., currently, 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 facing the analysts.

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[11] 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[12]. 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

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

[12] 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.

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
- 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:

GRI; Baseline Projection Methodology

GRI represents firm and economy bulk power sales in its Baseline Projection Methodology in a similar fashion as in the EMM.[13] 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.

ICF Resources, Inc.; Electric and Gas Modeling System (EGUMS)

EGUMS, a linear programming model, endogenously represents economy trade.[14] 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.

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

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

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 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)[15] 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).[16]

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

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

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

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.[17] 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.[18] 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,[19] 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.

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)

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[17]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.

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

[19]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).

nonutility generation is projected as a function of utility avoided costs, industrial electricity prices, and retail electricity prices.[20] 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.[21] 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 nine Regional Reliability Council's, which are in turn, aggregates of individual utility forecasts.[22] 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.

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[20]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.

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

[22]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.

Insert Figure 5 here!

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. 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 endogenous 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.[23] 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 reduces emissions to specified limits.

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 indude 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 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 both intrafuel and interfuel switching. For example, required reductions in SO2 emissions can be accomplished in coal-fired or oil-fired units by using the same fuel type with a lower sulfur content. Another option is to decrease utilization of these fossil-fired units with comparatively high emission rates by increasing the utilization of capacity types that emit little or not SO_2 (gas-fired, nuclear, and renewable plants).

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

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 was modified to preserve additional chronological information to allow for energy 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.)[24] This was accomplished with a modified load

[23]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.

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

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 was extended to compute 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 is simply 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 includes 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 should both limit the processing burden of representing trade and maintain the information required to measure the savings resulting from trade.;

- 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; and

- 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. Next, an emissions penalty cost is incorporated into the variable cost used to determine the merit order. The merit order is then determined by raking the groups in ascending order of the total variable costs.

The total cost used to determine the merit order now involves a tradeoff between the operating and emissions costs. Low-sulfur fuels typically have higher fuel prices but have lower emissions costs than high-sulfur fuels. Depending on the size of the SO_2 penalty cost, a plant could have a lower total cost using a low-sulfur fuel instead of the lower-priced high-sulfur fuel. Or, the result could be a repositioning of the merit order since plants that emit little or no SO_2 become more economically attractive compared to plants using high-sulfur fuel.

Therefore, the use of a penalty cost can adjust the total level of emissions in either of two ways. It may result in changes in the merit order so that plants consuming high-sulfur fuels are utilized less intensively. Alternatively, fuel switching may occur at plants that can use both high- and low-sulfur fuels. In either case, a higher penalty cost lowers the SO_2 emissions by finding the least expensive dollar to pound of SO_2 tradeoff in the merit order. This approach yields dispatch decisions that provide the lowest operating cost for the resulting sulfur dioxide emission level.

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 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 then determined as the product of fuel consumption and the corresponding emission rate, accounting for any reduction resulting from pollution control equipment. For each Compliance Group, the emissions are then summed over all plant types and regions and compared to the corresponding emissions limit. Total U.S. emissions are determined because the CAAA permits emissions trading nationwide.

The solution to the economic/environmental dispatch problem is achieved by iterating to find the smallest penalty cost that satisfies the emissions restrictions. The penalty cost is set to zero in the first iteration. A zero penalty cost implies that the available generating capacity is allocated on the basis of fuel and O&M costs, which represents the basic, least-cost approach. If no emissions constraint exists (e.g. before the CAAA requirements become effective in 1995) the penalty cost is zero. If a constraint is active, the procedure is still initially implemented with a zero penalty cost in order to determine if the restrictions can be met using economic dispatch. At the other extreme, an infinite emissions penalty corresponds to a least-emissions dispatch. This is equivalent to excluding the fuel and O&M costs when determining the merit order so that plant types are ranked in ascending order of emission rates.

The optimum solution lies between these two extremes. Least-cost dispatching would result in undercompliance and least-emissions dispatching would result in overcompliance. If the emissions resulting from a particular dispatch pattern exceed the specified level then the penalty cost is increased, a revised merit order is computed, and the available capacity is reallocated. If a particular penalty cost results in overshooting the target (i.e. emissions are reduced below the required level) then the penalty cost is relaxed and a new dispatch pattern is determined. Once the emissions target has been bracketed by two solutions (i.e. one penalty cost results in overcompliance and another results in undercompliance), linear interpolation is used to search for the lowest penalty cost such that the actual emissions match the allowable emissions, within a given tolerance.

A particular option for reducing emissions is to lower the total cost in the objective function only if the resulting increase in the operating costs is less than the corresponding decrease in the emissions cost. Thus, the objective function is minimized by including all intrafuel and interfuel switching until the incremental operating cost exceeds the emissions penalty cost. In effect, the penalty cost represents the marginal dispatching cost of reducing emissions to the required level. Further reductions in emissions would increase the objective function in proportion to the penalty cost, which would be lower than the corresponding increase in operating costs. The penalty cost is equivalent to the dual variable of the emissions constraint in the LP formulation, which describes the change in the cost corresponding to a unit change in emissions.

Therefore, the heuristic procedure searches for the most economical methods for reducing emissions to required levels. In doing so, it represents a nationwide allowance trading market. Utilities in some regions can reduce emissions below the amount allocated in the CAAA at a cost that does not exceed the marginal cost. Conversely, utilities in other regions cannot meet their targets in a cost-effective manner. This simulates a market where utilities with comparatively low reduction costs overcomply and sell the extra allowances to utilities with comparatively high reduction costs. For each electricity supply region, the difference between the actual emissions and the allowances allocated represents the amount of allowances bought or sold.

Once SO_2 compliance has been achieved, 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. SO_2 compliance is then reached.

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

Dimensions[25]

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
g	=	Sulfur dioxide compliance group

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)

[25] The 'e' dimension was the only new dimension added to the EFD to incorporate trade.

Plant Specific Information by Capacity Grouping

L_{ri} = SO_2 Allowances for Plant Type i in Region r (tons)

B_{ri} = Scrubber Removal Rate for Plant Type i in Region r (fraction)

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)

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

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

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.

$\Sigma_s M_{sri} \geq R_{ri}$ $\forall$ r and i

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

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

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

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

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

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

5) Generation requirements must include transmission and distribution losses

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

The representation of emissions restrictions, such as those specified for SO_2 in the CAAA, required an additional set of constraints.

6) 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. Unaffected units are not required to reduce emissions so the limit is assumed to be the sum of their current emissions.

   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). The product of these two results summed over all plants within a Compliance Group gives the total emissions for that Group.

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

7) 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

8) 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.

$\int_h \Sigma_i (EA_{rsieh}) \cdot \Sigma_i EK_{rie} \leq ETL_{yre} \qquad \forall$ 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. The EFD variables are in bold when applicable.

A.1 Model Parameters

TABLE A-1: EMM$PARM Common DESCRIPTION

Field	Units	Variable	Value	Source
Max. Number of Vertical Slices	**Numeric**	**EFD$MVS**	**60**	**Assumption**
Number of Seasonal Periods	**Numeric**	**EFD$MSP**	**6**	**Assumption**
Number of Renewable Types	**Numeric**	**EFD$RNW**	**8**	**Assumption**
# of Dispatchable Capacity Types	**Numeric**	**EFD$DSP**	**16**	**Assumption**
Number of ECP Fuels per Plant	Numeric	EFD$FPP	4	Assumption
Number of Plant Groups	**Numeric**	**EFD$MPG**	**300**	**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$MHG**	**120**	**Assumption**
Number of Horizontal Slices	**Numeric**	**EFD$MHS**	**EFD$MPG**	**Assumption**
Number of SO2 Compliance Groups	**Numeric**	**EFD$SO2**	**2**	**Assumption**
Number of Boiler Types	**Numeric**	**EFD$BTP**	**6**	**Assumption**
Supply/Reporting Regions per Fuel	**Numeric**	**EFD$FRG**	**3**	**Assumption**
Compliance Groups per Plant Group	**Numeric**	**EFD$CGP**	**1**	**Assumption**
Ownership Type	**Numeric**	**EFD$OWN**	**3**	**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$HRS**	**32**	**Assumption**
ECP Number of Load Groups	Numeric	ECP$STP	9	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$DSP	17	Assumption
ECP # of Intermittent Capacity Types	Numeric	ECP$INT	2	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
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$CAP	12	Assumption
Max Number of Plant Records	Numeric	WPLT$REC	20000	Assumption
Max Number of Plant Regions	Numeric	WPLT$RGN	20	Assumption
Max Number of Groups per Region	Numeric	WPLT$GRP	400	Assumption

Notes: Common = CN6005.PRJ.NEMS.COMMON.PDS.datekey(EMM$PARM)

TABLE A-2: PARAMETR Common 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 (10 + US)	Numeric	MNUMXR	11	Assumption
Coal Supply Regions (16 + US)	Numeric	MNUMLR	17	Assumption
Coal Demand Regions	**Numeric**	**NDREG**	**23**	**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 (C, CO, CO2, SOx, NOx, VOC, CH4, PART)	**Numeric**	**MNPOLLUT**	**8**	**Assumption**
Number of Manufacturing Types (1 = Nat, 2-8 = Non-Mfg, 9-29 = Mfg)	Numeric	MNFTYPE	29	Assumption
Number of Expectation Years (1990-2015, 2016-2066)	Numeric	MNXYR	66	Assumption
Number of Fuel Types (Oil, Natural Gas, MCL, Scl, Ren, Al)	**Numeric**	**FLTYPE**	**6**	**Assumption**
Emissions of Ethanol (5 Volume Steps)	Numeric	MNETOH	5	Assumption
Emissions (Corn & Biomass)	Numeric	MNCROP	2	Assumption
Number of Historical SEDS Years	Numeric	MSEDYR	2	Assumption

Notes: Common = CN6005.PRJ.NEMS.COMMON.PDS.datekey(PARAMETR)

EMM$PARM common block - parameter 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 Bituminous
2 Bituminous/Subbituminous
3 Subbituminous
4 Subbituminous/Lignite
5 Lignite
6 Oil Steam
7 Oil/Gas Steam
8 Gas Steam
9 Oil Turbine
10 Oil/Gas Turbine
11 Gas Turbines
12 Oil Combined Cycle
13 Oil/Gas Combined Cycle
14 Gas Combined Cycle

15 Nuclear BW
16 Nuclear PW

EFD$FPP = Number of Fuels Per Plant

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

EFD$MPG - Not Currently Used in the EFD

ETT$MTG - Not Currently Used in the EFD

ETT$RECS - Maximum Number of Constraints in File

EFD$MHG - Not Currently Used in the EFD

EFD$MHS - Number of Horizontal Slices

EFD$SO2 - Number of SO2 Compliance Groups

1 = Phase I Compliance
2 = Phase II Compliance

EFD$BTP - Not Currently Used in the EFD

EFD$FRG - Not Currently Used in the EFD

EFD$CGP - Not Currently Used in the EFD

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	$0.00 \leq SO_2 \leq 0.80$
Medium	$0.80 < SO_2 \leq 1.20$
High	$1.20 < SO_2 \leq 2.50$
Very High	$SO_2 > 2.50$

1 = UILL = Low Sulfur Lignite Coal
2 = UILM = Medium Sulfur Lignite Coal
3 = UILH = High Sulfur Lignite Coal
4 = UILV = Very High Sulfur Coal
5 = UISL = Low Sulfur Subbituminous Coal
6 = UISM = Medium Sulfur Subbituminous Coal
7 = UISH = High Sulfur Subbituminous Coal

8 = UISV = Very High Sulfur Subbituminous Coal
9 = UIBL = Low Sulfur Bituminous Coal
10 = UIBM = Medium Sulfur Bituminous Coal
11 = UIBH = High Sulfur Bituminous Coal
12 = UIBV = Very High Sulfur Bituminous Coal
13 = UIGF = Natural Gas - Firm
14 = UIGI = Natural Gas - Competitive
15 = UIGC = Natural Gas - Interruptible
16 = UIDS = Distillate Oil
17 = UIRL = Residual Low Sulfur Oil
18 = UIRH = Residual High Sulfur Oil
19 =
20 = UIUR = Uranium

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

<u>PARAMETR common block - parameter definitions</u>

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 (Census/NERC region)

1	=	New England/NE
2	=	Middle Atlantic/NY
3	=	Middle Atlantic/ECAR
4	=	Middle Atlantic/MAAC
5	=	South Atlantic/ECAR
6	=	South Atlantic/MAAC
7	=	South Atlantic/STV
8	=	South Atlantic/FL
9	=	East North Central/ECAR
10	=	East North Central/MAIN
11	=	East South Central/ECAR
12	=	East South Central/STV/SPP
13	=	West North Central/MAPP/RA
14	=	West North Central/MAIN
15	=	West North Central/SPP
16	=	West South Central/SPP
17	=	West South Central/ERCOT/RA
18	=	Mountain/NWP
19	=	Mountain/RA/SPP
20	=	Mountain/CNV
21	=	Pacific/ASCC
22	=	Pacific/NWP/CNV
23	=	Total

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)

A.2 Control Files

TABLE A-3: ECP$CNTL Common DESCRIPTION

Field	Units	Variable Name	Source
Technical Opt. - Disp. Capacity	GW	UPDOPT(DSP)	
Technical Opt. - Int. Capacity	GW	UPIOPT(INT)	
Technical Opt. - Ren. Capacity	GW	UPROPT(RNW)	
Learning Curve - Disp. Capacity	GW	UPDLC(DSP)	
Learning Curve - Int. Capacity	GW	UPILC(INT)	
Learning Curve - Ren. Capacity	GW	UPRLC(RNW)	
GNP Def.'s	Numeric	UPGNPD(MNUMYR+ECP$XPH)	
Real Cap Cost Def. - Disp. Capacity	GW	UPPCAPD(MNUMYR+ECP$XPH,DSP)	
Real Cap Cost Def. - Int. Capacity	GW	UPICAPD(MNUMYR+ECP$XPH,INT)	
Real Cap Cost Def. - Ren. Capacity	GW	UPRCAPD(MNUMYR+ECP$XPH,RNW)	
Target Cov Ratio-Pur. Constraint	Numeric	UPTCRT	
Initial Execution Year for ECP	Numeric	UPSTYR	
Length of Full Planning Horizon	Numeric	UNFPH	
Length of Expl. Planning Horizon	Numeric	UNXPH	
Vint. Type -(0=Ex.,1=New)- ECP Cap	Numeric	UPVTYP(CAP)	
Financial Type	Numeric	UPFTYP(CAP)	
NUG Bld SW(0=Not,1=Allowed)-DSP	Numeric	UPDNUG(DSP)	
NUG Bld SW(0=Not,1=Allowed)-Int	Numeric	UPINUG(INT)	
NUG Bld SW(0=Not,1=Allowed)-Ren	Numeric	UPRNUG(RNW)	
IRT Bld SW(0=Not, 1=Allowed)-DSP	Numeric	UPDETT(DSP)	
IRT Bld SW (0=Not, 1=Allowed)-Int	Numeric	UPIETT(INT)	
IRT Bld SW (0=Not, 1=Allowed)-Ren	Numeric	UPRETT(RNW)	
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$ECP(NFL,FPP)**	**Assumption**
Initialize Matrix (1=Yes, 0=No)	Numeric	ECP$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(CAP)**	**F860**
F860 Secondary Fuel Code	**Char**	**USF860(CAP)**	**F860**
Dsp. Plant Codes	**Char**	**UPPLCD(DSP)**	**Assumption**
Int. Plant Codes	**Char**	**UPIND(INT)**	**Assumption**
Ren. Plant Codes	**Char**	**UPRNCD(RNW)**	**Assumption**
DSM Group Codes	**Char**	**UPDMCD(DSM)**	**Assumption**
Fuel Codes	**Char**	**UPFLCD(NFL)**	**Assumption**
F860 Prime Mover Code	**Char**	**UPM860(CAP)**	**F860**
EFP Type	**Char**	**UPEFPT(CAP)**	**Assumption**
Fin Ownership Type (1='U',2='N')	**Char**	**UPOWNCD(OWN)**	**Assumption**
Load Segment Codes	**Char**	**UPLDCD(VLS)**	**Assumption**
Mode of Operation Codes	**Char**	**UPMDCD(VLS)**	**Assumption**
Region Codes	**Char**	**UPRGCD(RGN)**	**Assumption**
Year Codes	**Char**	**UPYRCD(FPH)**	**Assumption**
Retrofit Cluster Code	**Char**	**UPSCCD(CSR)**	**Assumption**
F759 Prime Mover Code	**Char**	**IPM759(CAP)**	**F759**
F759 Primary Fuel Code	**Char**	**UPF759(CAP)**	**F759**
F759 Secondary Fuel Code	**Char**	**USF759(CAP)**	**F759**

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

Common = CN6005.PRJ.NEMS.COMMON.PDS.datekey(ECP$CNTL)

TABLE A-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	

A.3 Inventory of Input Data

TABLE A-5: LOAD DAF FILE DESCRIPTION

This file contains the load shape information required to create both ECP and EFD load representations.

Field	Units	Variable Name	Indices	Source
Capacity of a slice	**MW**	**ULOAD**	**(HRS,GRP)**	**Assumption**
Maximum capacity within a time group	**MW**	**UG_MAX**	**(GRP)**	**Assumption**
Minimum capacity within a time group	**MW**	**UG_MIN**	**(GRP)**	**Assumption**
Number of hours in a season/time of day group	**hours**	**UTIME**	**(GRP)**	**Assumption**
Size of the step for ECP	Numeric	ECPSTSZ	(STP,SSZ)	
Group Definition	Numeric	UGROUPS		
# of Time Slice Groups	**Numeric**	**UNGRPS**	**(GRP)**	**Assumption**
Number of seasons	**season**	**EFDNSP2**		**Assumption**
Number of time of day subgroups in each season for EFD	**subgroup**	**EFDNUM**	**(SEASON)**	**Assumption**
A map to the GRP subscript (EFD)	**Numeric**	**EFDMAP**	**(SSN,SBGRP)**	**Assumption**
# of time slice groups for ECP	Numeric	ECPGRP		
Number of time of day subgroups in each season for ECP	subgroup	ECPNUM	(STP)	
A map to the GRP subscript (ECP)	Numeric	ECPMAP	(STP,SUBGRP)	
ECP - Step	Alpha	ECPSTEP	(STP)	
ECP - Planned/Unplanned Alpha	ECPTYPE		(GRP)	

Notes:

SEASON subscript values = 1 through 6 (6 seasons)
GRP subscript values = 1 through 18 (18 time of day/week groups)
SUBGRP subscript value = 1 through 3 (time of day subgroupings)
STP = 1 through 9 (ECP number of load groups)
SSZ = 1 through 5 (ECP maximum number of steps per group)
HRS = 1 through 32 (Number segments in each GRP)
EFDNUM = 3 for all seasons (in latest run).

Each record represents 1 NEMS region of data.
LRECL = 16,384
ACCESS = DIRECT
Filename = CN6005.PRJ.UTIL.LOADDAF.scenario.datekey
Common = CN6005.PRJ.NEMS.COMMON.PDS.datekey(LOADIN)
NEMS use = Output from the Load Pre-Processor run
Input to ETT Pre-Processor and EMM

TABLE A-6: PLANT DAF DESCRIPTION

This file contains the unit level data from a combination of the F860, F767, F867, F423, and the F759. New units are added to this file as determined by the ECP module. This is the source of EFD and ECP capacity data.

Field	Units	Variable	Values	Source
Total Name Plate Capacity of Unit	megawatt	WC_TOT	F860/F867	
Name Plate Actually 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	WSBEF		F767
SO2 Standard	numeric	WS2STD		F767
Actual SO2 Rate Achieved in Last Recorded Year	numeric	WS2ACT		F767
Average Capacity Factor	numeric	W_CF		F860/F759/Various
Avg Cost of Electricity using Primary Fuel	mill/kwh	WMKWH1		F423
Avg Cost of Electricity Using Secondary Fuel	mills/kwh	WMKWH2		F423
Weighted Avg Cost of Electricity	mill/kwh	WMKWH		F423
Primary Fuel Share	numeric	WPFSHR		F423
Secondary Fuel Share	numeric	WSCBCST		F423
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
Is Company Identified as Plant Operator	Numeric	W_OPER	0-Yes 1-No	F860
Code for Source of Average Capacity Factor	Numeric	WCFLAG		
Code for Source of Heatrate	Numeric	WHFLAG		
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
Flag	Numeric	W_CFLG	0-F860 1,3 Formula 3-Shares	Various
Plant Group	Numeric	W_GRP		Assumption
Plant Vintage	Numeric	WVIN		Assume (See values below)
Plant Name	Alpha	W_PNM		F860/F867
NEMS Fuel Codes for Actual Fuels Used (Prim.)	Numeric	WPFLS		Assumption
NEMS Fuel Codes for Actual Fuels Used (sec.)	Numeric	WSFLS		Assumption
Five Digit Company Identification Code	Numeric	W_CID		F860/F867
Zip Code for Plant Location	Numeric	WZIP		F860/F867
Code to Uniquely Identify Plant Location	Numeric	WCPLUS		Assumption
Four Digit Plant Identification Code	Numeric	W_PID		Assumption
Four Digit Unit Identification Code	Numeric	W_UID		Assumption
NEMS Fuel Codes	Numeric	WFL(FPP)		Assumption
F860 Primary Fuel Code	Numeric	WPF860		F860
F860 Secondary Fuel Code	Numeric	WSF860		F860
F860 Prime Mover Code	Numeric	WPM860		F860
Two Digit NEMS Plant Type Code	Numeric	WNEMST		F860/F867
NEMS Region Code for Plant Location	Numeric	WNOPER		F860/F867
NEMS Region Code for Unit Owner	Numeric	WNOWN		F860/F867
Two Digit Sate Code for Plant Location	Numeric	WSTATE		F860/F867
Census Region Number	Numeric	W_CR		F860/F867
Natural Gas Region Number	Numeric	W_GR		F860/F867
Coal Region Number	Numeric	W_CLRG		F860/F867
Current Status Code	Numeric	WSTAT1		F860/F867
Future Status Code	Numeric	WSTAT2		F860/F867
Financial Type Number for EFP	Numeric	WEFPT		F860/F867
Plant Type Number for ECP	Numeric	WECPT		F860/F867
F759 Prime Mover Code	Numeric	WPM759		F759
F759 Primary Fuel Code	Numeric	WPF759		F759
F759 Secondary Fuel Code	Numeric	WSF759		F759
Scrubber Type Code	Numeric	WSCBTP		

Ownership Type	Numeric	WFOWN	1=Prvt 2=Pblc 3=NUG	F860/F867
Boiler Type 1=Nonboiler	Numeric	WBTYP	F767	
Filler (Left Over)	Spaces	Unused bytes in PLNTIN common		

Values for Plant Vintage

0 = Canceled or Retired < 1990
1 = On Line by or before 1990
2 = Planned Additions
3 = Unplanned Additions
4 = Repowering (Before)
5 = Repowering (After)
6 = Planned Retrofit (Before)
7 = Planned Retrofit (After)
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"

LRECL = 512
ACCESS = DIRECT
Filename = CN6005.PRJ.UTIL.PLNTDAF.scenario.datekey
Common = CN6005.PRJ.NEMS.COMMON.PDS.datekey(PLNTIN)
NEMS use = Output from Plant Pre-Processor
Input to EMM

TABLE A-7: FUEL.DAF DESCRIPTION

This file provides storage and archival of utility sector fuel prices.

Field	Units	Variable Name	Source
Delivered Fuel Prices	\$/MMBTU	UPFUEL(NFL,FRGN)	Fuel Supply Modules
SO2 Emission Rate	lbs/mmBtu	UFRSO2(NFL,FRG)	Assumption
NOX Emission Rate	lbs/mmBtu	UFRNOX(NFL,FRG)	Assumption
CO2 Emission Rate	lbs/mmBtu	UFRCO2(NFL)	Assumption
Carbon Emission Rate	lbs/mmBtu	UFRCAR(NFL)	Assumption
CO Emission Rate	lbs/mmBtu	UFRCO1(NFL)	Assumption
VOC Emission Rate	lbs/mmBtu	UFRVOC(NFL)	Assumption
Ash Retention Rate	lbs/mmBtu	UFRASH(NFL)	Assumption
Heat Content MBTU	UFHCNT(NFL,FRG)		Assumption
Maximum Fuel Shares	Numeric	UCMFSH(DSP,FPP,RGN)	Assumption
Filler (Left Over)	Spaces	Unused bytes in	

FUELIN common

Notes: RGN subscript values = 1 through 16 (NEMS Rgns 1-13)
NFL subscript values = 1 through 20 (number of fuel types)
FRG subscript values = 1 through 24 (maximum # regions for any fuel type)
DSP subscript values = 1 through 16 (dispatchable capacity types)
FPP subscript values = 1 through 4 (ECP fuels per plant)

Each record represents 1 year of data.

LRECL = 16384
ACCESS = DIRECT
Filename = CN6005.PRJ.UTIL.FUELDAF.scenario.datekey
Common = CN6005.PRJ.NEMS.COMMON.PDS.datekey(FUELIN)
NEMS use = Output from Fuel Pre-Processor
Input to EMM

TABLE A-8: ETTIN FILE DESCRIPTION

Variable Name	Columns	Description	Units	Format	Comments	Source
IRGEX	1-3	Export Region	Numeric		I2	Assumption
IRGIM	4-6	Import Region	Numeric		I2	Assumption
CNSTRE	7-450	1990 Summer Constraint	GW	F7.3	The 12 years of	OE-411
CNSTRW		1990 Winter Constraint	GW	F7.3	Summer and Winter	OE-411
CNSTRE		1991 Summer Constraint	GW	F7.3	constraints are read	OE-411
CNSTRW		1991 Winter Constraint	GW	F7.3	in unformatted.	OE-411
CNSTRE		1992 Summer Constraint	GW	F7.3		OE-411
CNSTRW		1992 Winter Constraint	GW	F7.3	Each field should	OE-411
CNSTRE		1993 Summer Constraint	GW	F7.3	at have least	OE-411
CNSTRW		1993 Winter Constraint	GW	F7.3	3 decimal places	OE-411
CNSTRE		1994 Summer Constraint	GW	F7.3	The fields are	OE-411
CNSTRW		1994 Winter Constraint	GW	F7.3	separated from	OE-411
CNSTRE		1995 Summer Constraint	GW	F7.3	each other by a space.	OE-411
CNSTRW		1995 Winter Constraint	GW	F7.3		OE-411
CNSTRE		1996 Summer Constraint	GW	F7.3		OE-411
CNSTRW		1996 Winter Constraint	GW	F7.3		OE-411
CNSTRE		1997 Summer Constraint	GW	F7.3		OE-411
CNSTRW		1997 Winter Constraint	GW	F7.3		OE-411
CNSTRE		1998 Summer Constraint	GW	F7.3		OE-411
CNSTRW		1998 Winter Constraint	GW	F7.3		OE-411
CNSTRE		1999 Summer Constraint	GW	F7.3		OE-411
CNSTRW		1999 Winter Constraint	GW	F7.3		OE-411
CNSTRE		2000 Summer Constraint	GW	F7.3		OE-411
CNSTRW		2000 Winter Constraint	GW	F7.3		OE-411
CNSTRE		2001 Summer Constraint	GW	F7.3		OE-411
CNSTRW		2001 Winter Constraint	GW	F7.3		OE-411
.		.				Assumption
.		.				.
.		.				.
CNSTRW		2020 Winter Constraint	GW	F7.3		Assumption

Notes: LRECL = 500

BLKSIZE = 5000

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

Filename = CN6005.PRJ.UTIL.ETTIN.scenario.datekey
NEMS use = Output from ETT Pre-processor and Input to the EMM.

This file contains region to region constraints for the years 1990-2020. The ETT Pre-Processor reads in the 'CNSRNT' file, subtracts out Firm Power Contracts from the constraints, and outputs the result in the 'ETTIN' file.

TABLE A-8a: CONSTRAINTS FILE DESCRIPTION (ETT Pre-Processor Input File)

Variable Name	Columns	Description	Units	Format	Comments	Source
IRGEX	1-2	Export Region	Numeric		I2	Assumption
IRGIM	4-5	Import Region	Numeric		I2	Assumption
TEMPS	6-255	1990 Summer Constraint	GW	F7.3	The 12 years of	OE-411
TEMPW		1990 Winter Constraint	GW	F7.3	Summer and Winter	OE-411
TEMPS		1991 Summer Constraint	GW	F7.3	constraints are read	OE-411
TEMPW		1991 Winter Constraint	GW	F7.3	in unformatted.	OE-411
TEMPS		1992 Summer Constraint	GW	F7.3		OE-411
TEMPW		1992 Winter Constraint	GW	F7.3	Each field should	OE-411
TEMPS		1993 Summer Constraint	GW	F7.3	have at least 3	OE-411
TEMPW		1993 Winter Constraint	GW	F7.3	decimal places.	OE-411
TEMPS		1994 Summer Constraint	GW	F7.3	The fields are	OE-411
TEMPW		1994 Winter Constraint	GW	F7.3	separated from	OE-411
TEMPS		1995 Summer Constraint	GW	F7.3	each other by a space.	OE-411
TEMPW		1995 Winter Constraint	GW	F7.3		OE-411
TEMPS		1996 Summer Constraint	GW	F7.3		OE-411
TEMPW		1996 Winter Constraint	GW	F7.3		OE-411
TEMPS		1997 Summer Constraint	GW	F7.3		OE-411
TEMPW		1997 Winter Constraint	GW	F7.3		OE-411
TEMPS		1998 Summer Constraint	GW	F7.3		OE-411
TEMPW		1998 Winter Constraint	GW	F7.3		OE-411
TEMPS		1999 Summer Constraint	GW	F7.3		OE-411
TEMPW		1999 Winter Constraint	GW	F7.3		OE-411
TEMPS		2000 Summer Constraint	GW	F7.3		OE-411
TEMPW		2000 Winter Constraint	GW	F7.3		OE-411
TEMPS		2001 Summer Constraint	GW	F7.3		OE-411
TEMPW		2001 Winter Constraint	GW	F7.3		OE-411
		Export Region Name	Alpha	A10		Assumption
		Import Region Name	Alpha	A10		Assumption

Notes: LRECL=255
BLKSIZE = 23460

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

Filename = CN6005.PRJ.UTIL.CNSTNT.scenario.datekey
NEMS use = Input to Pre-Processor Program

This file contains region to region constraints for the years 1990-2001. The ETT Pre-Processor reads in the 'CNSRNT' file, subtracts out firm power commitments from the constraints, and outputs the result in the 'ETTIN" file.

TABLE A-8b: CONTRACTS FILE DESCRIPTION (ETT Pre-Process Input File)

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 Record	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: LRECL = 136
BLKSIZE = 7344
Filename = CN6005.PRJ.UTIL.ETCNCT.scenario.datekey
NEMS use = Input to ETT Pre-Processor Program

OE-411: DOE Form OE-411, "Coordinated Bulk Power Supply Program Report".
F860 - "Annual Electric Generator Report"

This file contains records for firm power contracts between NEMS regions, between NEMS regions and Canada, and between NEMS regions and Mexico.

TABLE A-8c: CANADIAN SUPPLY FILE DESCRIPTION (ETT Pre-Processor Input File)

Variable Names	Columns	Description	Units	Format	Comments	Source	
SPCNRGN	9-12	Canadian Reg (Sell)	Numeric	F4.0	UCI$CRG	Assumption	
SPNEMS	18-21	NEMS Region (Buyer)	Numeric	F4.0		Assumption	
SPSTEP	24	Step #	Numeric	I1		Assumption	
SPYR	27-30	Year	Numeric	I4		Northern Lights	
SPRHS	33-39	Firm MW Available	MW	F7.1	UCI$FMW	Northern Lights	SPPKRHS
	42-48	Peak MW Available	MW	F7.1	UCI$PMW	Northern Lights	
SPCF	54-57	Capacity Factor	Numeric	F4.1	UCI$CF	Northern Lights	

SPDOLL	61-66	Fixed Cost	$/Kw	F6.1		Northern Lights
SPMILLS	71-75	Variable Cost	Mills/Kwh	F5.2	UCI$CST	Northern Lights

Notes: LRECL=80
BLKSIZE = 7440
Filename = CN6005.PRJ.UTIL.CANSPPLY.scenario.datekey
NEMS use = Input to ETT Pre-processor program

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

The Canadian Supply file is pre-dominantly used for input to the ECP; i.e. 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.

TABLE A-9: ETTDEM.DAF (EIJ File) DESCRIPTION

Description	Units	Variable Name	Indices	Source
Net Interregional Flows	GW	UEITAJ	(SSN,RG)	PreProcessor
Canadian Builds	GW	UCANBLD	(RGN)	ECP Output
T & D Loss Factor	Numeric	UQTDLS	(RGN)	Assumption
Max Summer Imp Cnstrnt	GW	URNCSI	(RGN)	NERC
Max Summer Exp Cnstrnt	GW	URNCST	(RGN)	NERC
Max Winter Exp Cnstrnt	GW	URNCWT	(RGN)	NERC
Max Winter Imp Cnstrnt	GW	URNCWI	(RGN)	NERC
Firm Power Sales (Net)	MWH	ZTDMMF	(RGN)	ECP Output
Firm Power Sales (Gross)	MWH	ZTEXMF	(RGN)	ECP Output
Firm Power Sales (Net)	MM$	ZTDMDF	(RGN)	ECP Output
Firm Power Sales (Gross)	MM$	ZTEXDF	(RGN)	ECP Output
Internatnl Firm Pwr Imports	MWH	ZTIMPF	(RGN)	ECP Output
Internatnl Firm Pwr Imports	MM$	ZTIMPD	(RGN)	ECP Output
Internatnl Firm Pwr Exports	MM$	ZTEXPD	(RGN)	ECP Output
Internatnl Firm Pwr Exports	MWH	ZTEXPF	(RGN)	ECP Output
Firm Pwr Avail(Canadian)	MW	UCI$FMW	(STP,RGN)	Northern Lights
Peak Pwr Avail(Canadian)	MW	UCI$PMW	(STP,RGN)	Northern Lights
Cap Factor(Canadian)	Numeric	UCI$CF	(STP,RGN)	Northern Lights
Variable Cost (Canadian)	Mils/Kwh	UCI$CST	(STP,RGN)	Northern Lights
Canadian Expt Rgn (Can.)	Numeric	UCI$CRG	(STP,RGN)	Northern Lights
Filler (Left Over)	Spaces	Unused bytes in DISPET3 common		

Notes: LRECL = 2048
ACCESS = Direct
Filename = CN6005.PRJ.UTIL.ETTDEM.scenario.datekey

Common = CN6005.PRJ.NEMS.COMMON.PDS.D1123931:DISPETT
NEMS Use = Output from ETT Pre-Processor/Input to EMM

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

RGN subscript values = 1 through 16 (NEMS electricity supply regions
STP subscript values = 1 and 2 (1 = low cost, 2 = high cost)
UPDATE SEASON subscript values = 1 through 6; 1 = January and February; 2 = December and March; 3 = May and April; 4 = June and September; 5 = July and August; 6 = November and October.
Each record represents 1 year of data.

Table A-10: DISPETT Common Block Description

Description	Variable	Indices	Units	Source
	AREATR	(EFDMSP,ETTMTG,EFD$MVS)		
	AREATI	(EFDMSP,ETTMTG,EFD$MVS)		
	CAPTR	(EFDMSP,ETTMTG,EFD$MVS)		
	CAPTRI	(EFDMSP,ETTMTG,EFD$MVS)		
	ETDSPN	(EFD$MSP)		
	ETDSPT	(EFDMSP,EFDMPG)		
	UCASTS	(EFD$MPG)		
	ETFSHR	(EFDMSP,EFDMPG,EFD$FPP)		
	IMMAP	(EFDMSP,ETTMTG,EFD$MVS)		
	EXMAP	(EFDMSP,ETTMTG,EFD$MVS)		U N T C O S
	(EFDMSP,EFDMPG)			
	IRGNUM	(MNUMNR)		
Y values-ordered pairs-ETT curve	TTYVAL	(EFD$MVS)		
Y values-ordered pairs-ETT curve	(TIYVAL	(EFD$MVS)		
Area under "original" load curve	AREANT	(EFDMPG,EFDMVS)		
Area under "export" load curve	AREATT	(EFDMPG,EFDMVS)		
Area under "import" load curve	AREAIT	(EFDMPG,EFDMVS)		
	IMAREA	(EFD$MVS)		
	EXAREA	(EFD$MVS)		
International Interrupt Imports	2IMPCI	(MNUMYR,MNUMNR)		
International Interrupt Exports	EXPCI	(MNUMYR,MNUMNR)		
	IDONE1			
	IDONE2			
Net Interregional Electricity Flows	UEITAJ	(EFD$MSP,MNUMNR)		
Canadian Build Decision	UCANBLD	(MNUMNR)		
T&D Loss Factor	UQTDLS	(MNUMNR)		
Max Summer Import Constraint	URNCSI	(MNUMNR)		

Max Summer Export Constraint	URNCST	(MNUMNR)
Max Winter Export Constraint	URNCWT	(MNUMNR)
Max Winter Import Constraint	URNCWI	(MNUMNR)
Firm Power Sales(MWH)	ZTDMMF	(MNUMNR)
	ZTEXMF	(MNUMNR)
Firm Power Sales (MM$)	ZTDMDF	(MNUMNR)
	ZTEXDF	(MNUMNR)
Canadian Firm Imports(mwh)	ZTIMPF	(MNUMNR)
Canadian Firm Imports (MM$)	ZTIMPD	(MNUMNR)
Canadian Firm Exports (MM$)	ZTEXPD	(MNUMNR)
Canadian Firm Exports MWH	ZTEXPF	(MNUMNR)
Firm MW Available	UCI$FMW	(ECP$CIS,MNUMNR)
Peak MW Available	UCI$PMW	(ECP$CIS,MNUMNR)
Capacity Factor	UCI$CF	(ECP$CIS,MNUMNR)
Cost (Mills/KWH)	UCI$CST	(ECP$CIS,MNUMNR)
Canadian Export	UCI$CRG	(ECP$CIS,MNUMNR)

TABLE A-11: NUGPIPE FILE DESCRIPTION

Variable Name	Columns	Description	Units	Format	Source
LINELOSS	1-4	Line Loss Factor	Pct.	F4.0	Memo
PRTHRESH	10-13	Price Threshold	mill/kwh	F4.0	Assumption
CGOTPV	*19-22	'Other' Cogen Var. Cost	mill/kwh	F4.0	Assumption
CGOTPF	*28-31	'Other Cogen Fix. Cost	$/kw	F4.0	Assumption
CGCOMPV	*37-40	Comm. Cogen Var. Cost	mill/kwh	F4.0	Assumption
CGCOMPF	*46-49	Comm. Cogen. Fix. Cost	$/kw	F4.0	Assumption
CGINDPV	*55-58	Ind. Cogen Var. Cost	mill/kwh	F4.0	Assumption
CGINDPF	*64-67	Ind. Cogen Fix. Cost	$/kw		Assumption
IMPCI	*4-189	Canadian Interruptible Imports	Mwh	21(F9.0)	Exogenous
EXPCI	4-189	Canadian Interruptible Exports	Mwh	21(F9.0)	Exogenous
CID	1-6	Company Id	num.	F6.0	F867
FID	8-12	Facility Id	num.	F5.0	F867
SIC	14-15	SIC	num.	F2.0	F867
STATE	19-20	State abbrev.	Alpha.	A2	F867
ZIP	22-26	Zip code	num.	F5.0	F867
NEMS	29-30	NEMS region id	num.	I2	F867
CENSUS	32-33	Census region id.	num.	F2.0	F867
GID	35-38	Generator id.	Alpha.	A4	F867
HRATE	40-44	Heatrate	num.	F5.0	Assumption
PFL	45-47	Primary Fuel Type	Alpha	A3	F867
SFL	50-52	Secondary Fuel Type	Alpha	A3	F867
CAP	55-59	Capacity	MW	F5.2	F867
STATUS	60-61	Status	Alpha	A2	F867
PM	65-66	Prime Mover Type	Alpha	A2	F867
SMTH	70-71	Start Month	num.	F2.0	F867
SYR	75-78	Start Year	num.	F4.0	F867
RMTH	80-81	Retirement Month	num.	F2.0	F867
RYR	85-88	Retirement Year	num.	F4.0	F867
GENGRD	95-103	Sales to Grid Gener.	Kwh	F9.0	F867
GENOWN	105-113	Self Generation	Kwh	F9.0	F867

Note: The NUGPIPE file is input to the EFD in the RDNUGS subroutine in the 'NUGS' code, i.e. through the

&6005PRJ.NEMS.FORTRN.UNUGS.D121593P code.

F867 - "Annual Nonutility Power Producer Report".
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 A-12: SO2 CONTROL 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

LRECL = 80
Blksize = 7440
Filename = CN6005.PRJ.UTIL.SO2CNTL.scenario.datekey
NEMS use = Input to EMM
Common = CN6005.PRJ.NEMS.COMMON.PDS.D1123932(uso2grp)

TABLE A-13: ELGNRCR FILE DESCRIPTION

This file contains electricity generation data for Census divisions within NEMS regions. The first record is a label record. Subsequent records contain data for one NEMS region. Records are read in unformatted with a space between each data item.

Record Type	Field	Units	Variable	Comments	Source
1	Label	Alpha	DUMMY	'EL DEM',then Census div #s	Assumption
2	NEMS Region	Numeric	INERC	1 through 16	Assumptions
2	Generation Fields (11)	MWh	ELGNNRCR(INERC,CRG)		F759

Notes: INERC subscript values = 1 through 16 (on input record)
CRG subscript values = 1 through 11 (Census divisions, MNUMNCR parameter)

LRECL = 133
Blksize = 6233
Filename = CN6005.PRJ.UTIL.ELGNRCR.scenario.datekey
NEMS use = Input to EMM
Common = CN6005.PRJ.NEMS.COMMON.PDS.D1123932(el$shrs)

F759 - "Monthly Power Plant Report".

TABLE A-14: 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.

Record Type	Field	Units	Variable	Comments	Source
1	Year	Numeric	IYR	4 digits	
	Nuclear Capacity Factors		UNUCFNR(RG,YR)	YR = IYR - 1989 RG = 1,MNUMNR-1	OIAF
	Record Id	Alpha		'NUC CF'	
2	Year	Numeric	IYR	4 digits	
	Annual Nuclear Fuel Costs		UPURELN(RG,YR)	YR = IYR - 1989 RG = MNUMNR	OIAF
	Record Id	Alpha		'NUC FLCST"	
3	Year	Numeric	IYR	4 digits	
	Coal Generation		HGNCLNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'CLGEN'	
4	Year	Numeric	IYR	4 digits	
	Oil Generation		HGNOLNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'OLGEN'	
5	Year	Numeric	IYR	4 digits	
	Gas Generation		HGNNGNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'NGGEN'	
6	Year	Numeric	IYR	4 digits	
	Nuclear Generation		HGNNUNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'NUGEN'	
7	Year	Numeric	IYR	4 digits	
	Pumped Storage Generation		HGNPSNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'PSGEN'	
8	Year	Numeric	IYR	4 digits	
	Nat Gas Generation		HGNGENR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'GEGEN'	
9	Year	Numeric	IYR	4 digits	
	MSW Generation		HGNMSNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'MSGEN'	
10	Year	Numeric	IYR	4 digits	
	Wood Generation		HNWDNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'WDGEN'	
11	Year	Numeric	IYR	4 digits	
	Solar Generation		HGNSONR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'SOGEN'	

12	Year	Numeric	IYR	4 digits	
	Photovoltaic Generation		HGNPVNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'PVGEN'	
13	Year	Numeric	IYR	4 digits	
	Wind Generation		HNWNNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'WNGEN'	
14	Year	Numeric	IYR	4 digits	
	Hydro Generation		HGNHYNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'HYGEN'	
15	Year	Numeric	IYR	4 digits	
	Other Generation		HGNOTNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'OTGEN'	
16	Year	Numeric	IYR	4 digits	
	Coal Fuel Consumption		HFLCLNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'CLCON'	
17	Year	Numeric	IYR	4 digits	
	Oil Fuel Consumption		HFLOLNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'OLCON'	
18	Year	Numeric	IYR	4 digits	
	Gas Fuel Consumption		HFLNGNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F759
	Record Id	Alpha		'NGCON'	
19	Year	Numeric	IYR	4 digits	
	Residential Sales		HELRSNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F861
	Record Id	Alpha		'RSDEM'	
20	Year	Numeric	IYR	4 digits	
	Commercial Sales		HELCMNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F861
	Record Id	Alpha		'CMDEM'	
21	Year	Numeric	IYR	4 digits	
	Industrial Sales		HELINNR(1,RG,YR)	YR = IYR - 1989 RG = 1, MNUMNR	F861
	Record Id	Alpha		'INDEM'	
22	Year	Numeric	IYR	4 digits	
	Transportation Sales		HELTRNR(1,RG,YR)	YR = IYR - 1989 RGN = 1, MNUMNR	F861
	Record Id	Alpha		'TRDEM'	
23	Year	Numeric	IYR	4 digits	
	Other Sales		HELOTNR(1,RG,YR)	YR = IYR - 1989 RGN = 1, MNUMNR	F861
	Record Id	Alpha		'OTDEM'	

24	Year	Numeric	IYR	4 digits	
	Total Sales		HELASNR(1,RG,YR)	YR = IYR - 1989	F861
				RG = 1, MNUMNR	
	Record Id	Alpha		'ASDEM'	
25	Year	Numeric	IYR	4 digits	
	Nonutility Own Use Cons.			YR = IYR - 1989	F867
				RG = 1, MNUMNR	
	Record Id	Alpha		'NUDEM'	
26	Year	Numeric	HEMNGTL	4 digits	
	Emissions from Nat. Gas			YR = IYR - 1989	EPA 92
				Emission=1,6	
				1 = Carbon	
				2 = CO_1	
				3 = CO_2	
				4 = SO_2	
				5 = NO_x	
				6 = VOC	
27	Year	Numeric	HEMOLTL	4 digits	
	Emissions from Oil			YR = IYR - 1989	EPA 92
				Emission=1,6	
				1 = Carbon	
				2 = CO_1	
				3 = CO_2	
				4 = SO_2	
				5 = NO_x	
				6 = VOC	
28	Year	Numeric	HEMCLTL	4 digits	
	Emissions from Coal			YR = IYR - 1989	EPA 92
				Emission=1,6	
				1 = Carbon	
				2 = CO_1	
				3 = CO_2	
				4 = SO_2	
				5 = NO_x	
				6 = VOC	
29	Year	Numeric	HEMCLTL	4 digits	
	Emissions from Other			YR = IYR - 1989	EPA 92
				Emission=1,6	
				1 = Carbon	
				2 = CO_1	
				3 = CO_2	
				4 = SO_2	
				5 = NO_x	
				6 = VOC	
30	Year	Numeric	IYR	4 digits	
	Nonutility Coal Gen		HGNCLNR(2,RG,YR)	YR = IYR - 1989	F867
				RG = 1, MNUMNR	
	Record Id	Alpha		'CLGEN'	
31	Year	Numeric	IYR	4 digits	
	Nonutility Oil Gen		HGNOLNR(2,RG,YR)	YR = IYR - 1989	F867
				RG = 1, MNUMNR	

	Record Id	Alpha		'OLGEN'	
32	Year	Numeric	IYR	4 digits	
	Nonutility Gas Gen		HGNNGNR(2,RG,YR)	YR = IYR - 1989	F867
				RGN = 1, MNUMNR	
	Record Id	Alpha		'NGGEN'	
33	Year	Numeric	IYR	4 digits	
	Nonutility Nuclear Gen		HGNNUNR(2,RG,YR)	YR = IYR - 1989	F867
				RG = 1, MNUMNR	
	Record Id	Alpha		'NUGEN'	
34	Year	Numeric	IYR	4 digits	
	Nonutil Pumped Storage		HGNPSNR(2,RG,YR)	YR = IYR - 1989	F867
				RGN = 1, MNUMNR	
	Record Id	Alpha		'PSGEN'	
35	Year	Numeric	IYR	4 digits	
	Geothermal Generation		HGNGENR(2,RG,YR)	YR = IYR - 1989	F867
				RGN = 1, MNUMNR	
	Record Id	Alpha		'GEGEN'	
36	Year	Numeric	IYR	4 digits	
	Nonutility MSW Gen		HGNMSNR(2,RG,YR)	YR = IYR - 1989	F867
				RG = 1, MNUMNR	
	Record Id	Alpha		'MSGEN'	
37	Year	Numeric	IYR	4 digits	
	Nonutil Wood Gen		HNWDNR(2,RG,YR)	YR = IYR - 1989	F867
				RGN = 1, MNUMNR	
	Record Id	Alpha		'WDGEN'	
38	Year	Numeric	IYR	4 digits	
	Nonutil Solar Gen		HGNSONR(2,RG,YR)	YR = IYR - 1989	F867
				RG = 1, MNUMNR	
	Record Id	Alpha		'SOGEN'	
39	Year	Numeric	IYR	4 digits	
	Nonutil Photovoltaic Gen		HGNPVNR(2,RG,YR)	YR = IYR - 1989	F867
				RG = 1, MNUMNR	
	Record Id	Alpha		'PVGEN'	
40	Year	Numeric	IYR	4 digits	
	Nonutil Wind Gen		HNWNNR(2,RG,YR)	YR = IYR - 1989	F867
				RG = 1, MNUMNR	
	Record Id	Alpha		'WNGEN'	
41	Year	Numeric	IYR	4 digits	
	Nonutil Hydro Gen		HGNHYNR(2,RG,YR)	YR = IYR - 1989	F867
				RG = 1, MNUMNR	
	Record Id	Alpha		'HYGEN'	
42	Year	Numeric	IYR	4 digits	
	Other Nonutility Gen		HGNOTNR(2,RG,YR)	YR = IYR - 1989	F867
				RGN = 1, MNUMNR	
	Record Id	Alpha		'OTGEN'	
43	Year	Numeric	IYR	4 digits	

	Internat Firm Imports		HTIMPF(NERC,YR)	YR = IYR - 1 RG = 1,MNUMNR	FE-781R/NEB
44	Year Internat Economy Imp	Numeric	IYR HTIMPE(NERC,YR)	4 digits YR = IYR - 1 RG = 1,MNUMNR	 FE-781R/NEB
45	Year Internat Firm Export	Numeric	IYR HTEXPF(NERC,YR)	4 digits YR = IYR - 1 RG = 1, MNUMNR	 FE-781R/NEB
46	Year Internat Economy Exp	Numeric	IYR HTEXPE(NERC,YR)	4 digits YR = IYR - 1 RG = 1, MNUMNR	 FE-781R/NEB
47	Year Cogen - Grid	Numeric	IYR HCGGRD(NERC,YR)	4 digits YR = IYR - 1 RG = 1, MNUMNR	 F867
48	Year Cogen - Own Use	Numeric	IYR HCGOWN(NERC,YR)	4 digits YR = IYR - 1 RG = 1, MNUMNR	 F867

Notes: LRECL = 200
Blksize = 7400
Filename = CN6005.PRJ.UTIL.ELDATYR.scenario.datekey
NEMS use = Input to EMM

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 A-15: DISPINYR Common Block Description

Description	Variable	Indices	Units	Source
COAL GEN BY OWNERSHIP TYPE	HGNCLNR	(2,MNUMNR,5)		F759/F867
GAS (FIRM) GEN/OWNERSHIP TYPE	HGNNGNR	(2,MNUMNR,5)		F759/F867
DS GEN BY OWNERSHIP TYPE/NERC	HGNOLNR	(2,MNUMNR,5)		F759/F867
NUC GEN BY OWNERSHIP TYPE/NERC	HGNURNR	(2,MNUMNR,5)		F759/F867
PS GEN BY OWNERSHIP TYPE/NERC	HGNPSNR	(2,MNUMNR,5)		F759/F867
HYD (NOT PS) GEN/OWNERSHIP TYPE	HGNHYNR	(2,MNUMNR,5)		F759/F867
GEOTHERMAL GEN/OWNERSHIP TYPE	HGNGENR	(2,MNUMNR,5)		F759/F867
MSW GEN BY OWNERSHIP TYPE/NERC	HGNMSNR	(2,MNUMNR,5)		F759/F867
WIND GEN BY OWNERSHIP TYPE/NERC	HGNWDNR	(2,MNUMNR,5)		F759/F867
Solar Gen by Ownership type/NERC	HGNSONR	(2,MNUMNR,5)		F759/F867
Photovoltaic Gen by Ownership type/NERC	HGNPVNR	(2,MNUMNR,5)		F759/F867
Wind Gen by Ownership type/NERC	HGNWNNR	(2,MNUMNR,5)		F759/F867
OTH GEN BY OWNERSHIP TYPE/NERC	HGNOTNR	(2,MNUMNR,5)		F759/F867
Tot. Gen by Ownership Type/NERC	HGNTLNR	(2,MNUMNR,5)		F759/F867
COAL CONS BY OWNERSHIP TYPE/NERC	HFLCLNR	(2,MNUMNR,5)		F759/F867
GAS CONS BY OWNERSHIP TYPE/NERC	HFLNGNR	(2,MNUMNR,5)		F759/F867
OIL CONS BY OWNERSHIP TYPE/NERC	HFLOLNR	(2,MNUMNR,5)		F759/F867
RESIDENTIAL	HELRSNR	(MNUMNR,5)		F861
COMMERCIAL	HELCMNR	(MNUMNR,5)		F861

INDUSTRIAL	HELINNR	(MNUMNR,5)	F861
TRANSPORTATION	HELTRNR	(MNUMNR,5)	F861
OTHER	HELOTNR	(MNUMNR,5)	F861
ALL SECTORS	HELASNR	(MNUMNR,5)	F861
PURCHASES FROM NONUTILITIES	HELNUNR	(MNUMNR,5)	F867
FIRM IMPORTS	HTIMPF	(MNUMNR,2)	FE-781R
ECONOMY IMPORTS	HTIMPE	(MNUMNR,2)	FE-781R
FIRM EXPORTS	HTEXPF	(MNUMNR,2)	FE-781R
ECONOMY EXPORTS	HTEXPE	(MNUMNR,2)	FE-781R
COGENERATION TO GRID	HCGGRD	(MNUMNR,2)	F867
COGENERATION OWN USE	HCGOWN	(MNUMNR,2)	F867
GAS (C,CO,CO2,SO2,NOX,VOC)	HEMNGTL	(MNPOLLUT,5)	EPA 92
OIL (C,CO,CO2,SO2,NOX,VOC)	HEMOLTL	(MNPOLLUT,5)	EPA 92
COAL (C,CO,CO2,SO2,NOX,VOC)	HEMCLTL	(MNPOLLUT,5)	EPA 92
REN (C,CO,CO2,SO2,NOX,VOC)	HEMOTTL	(MNPOLLUT,5)	EPA 92
CAPACITY FACTORS	UNUCFNR	(MNUMNR,MNUMYR)	OIAF
FUEL PRICES	UPURELN	(MNUMNR,MNUMYR)	OIAF

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 A-16: INPTDAF FILE DESCRIPTION

The majority of the input data for the EFD is stored in the INPTDAF (CN6005.PRJ.UTIL.INPTDAF. <scenario>.<datekey>) file. This file contains exogenous inputs, load curve and demand information, trade constraints, and cost and performance information by plant group. Existing and planned units are grouped based on their physical locations (i.e. by census, fuel and electricity supply regions), their plant type and retirement year. The plants are grouped in this manner to speed and simplify the dispatch decision. The INPTDAF is loaded into the DISPIN common block by region and by year (since dispatching is done on a regional basis), again to speed the dispatch decision.

Field	Units	Variable Name	Indices	Source
Y Value of Seasonal Load Curve	GW	ELYVAL	(VS,SEASON)	Demand Modules
X Value of Seasonal Load Curve	Normalized Hours	ELXVAL	(VS,SEASON)	Assumption
Number of Hours per Season	hours	EETIME	(SEASON)	Assumption
Seasonal Demand Share	Numeric	EESSHR	(SEASON)	Assumption
Conversion Factor	Numeric	EFACTR		Assumption
Renewable Capacity	GW	EHCAP	(REN,SSN)	F860/F867
Renewable Heatrate	Btu/Kwh	EHHTRT	(REN)	Assumption
Variable O&M	MM$	EHVOMR	(REN)	Assumption
Total Electricity Demand	GWH	EQEL		Demand Modules
Transmission & Distribution Loss Factor	Numeric	EQTDLS		Assumption
Net Exports	GW	EEITAJ	(SEASON)	OE-411 & EFD Output
Total Fixed O&M	MM$	ERTOMF		Assumption
Conventional Capacity	GW	ECCAP	(PLGRP,SSN)	F860/F867/ECP Output
Capacity Net of Planned Maintenance	GW	ECCOPM	(PLGRP,SSN)	Assumption
Variable O&M	MM$	ECOMR	(PLGRP,FPP)	Assumption
Heatrate	Btu/KWH	ECHTRT	(PLGRP,FPP)	Assumption
Allowances	Tons	ECALLW	(PLGRP)	
Maximum Fuel Shares	Numeric	ECMFSH	(DSP,FPP,SSN)	F767
Capacity Factor Bounds	Numeric	ECCFBD	(DSP,2)	Assumption
SO2 Penalty Cost	$/Ton	EPSO2	(SO2)	Zero or EFD Output
Summer Import Transmission Constraint	GW	TRNCSI		OE-411
Summer Export Transmission Constraint	GW	TRNCST		OE-411

Winter Import Transmission Constraint	GW	TRNCWI		OE-411
Winter Export Transmission Constraint	GW	TRNCWT		OE-411
Number of Renewable Groups	Numeric	EHNTP		Assumption
Number of Seasonal Periods	Numeric	EENSP		Assumption
Number of Points in Load Curve	Numeric	ELNVCT	(SEASON)	Assumption
Number of Capacity Groups	Numeric	ECNTP		Assumption
Number of Dsp. Plant Type Groups	Numeric	EIPGRP		Assumption
Number of Renewable Plant Type Groups	Numeric	EIHGRP		Assumption
Number of Fuels Per Plant	Numeric	EIFPLT		Assumption
Number of SO2 Compliance Groups	Numeric	EIMCG		Assumption
Time of Day/Season Group Index	Numeric	ELGRP	(VS,SSN)	Assumption
Time of Day/Season Segment Index	Numeric	ELSEG	(VS,SSN)	Assumption
Number of Time of Day Groups	Numeric	ELNGRP		Assumption
Time of Day per Day/Season Groups	Numeric	ELNSPG	(DAY)	Assumption
Number of Segments per Group	Numeric	EFDNSP	(DAY)	Assumption
Index for EFD Slice/Group Segment	Numeric	EFDGRP	(HR,DAY)	Assumption
Renewable Capacity Factor	Numeric	EHHYCF	(REN,SSN)	Assumption
Renewable Type	Numeric	EHHYTP	(REN)	Assumption
Fuel Type per Capacity Group	Numeric	ECFLTP	(PLGRP,FPP,FRG)	Assumption
Fuel & Cap. Group Index	Numeric	ECFLRG	(PLGRP,FPP,FRG)	Assumption
Maximum Capacity Factor	Numeric	ECMXCP	(PLGRP)	Assumption
Planned Maintenance Rate	Numeric	ECPMR	(PLGRP)	Assumption
Forced Outage Rate	Numeric	ECFOR	(PLGRP)	Assumption
Capacity Type	Numeric	ECASTS	(PLGRP)	F860/F867/ECP Output
Scrubber Efficiency	Numeric	ECSCRB	(PLGRP)	Assumption
Compliance Group	Numeric	EISO2	(PLGRP,CGRP)	Assumption
Plant Group Ownership Type (pri,pub,ewg)	Numeric	ECFOWN	(PLGRP)	F860/F867
Plant Group Census Region	Numeric	ECCR	(PLGRP)	Assumption
Plant Group NEMS Region	Numeric	ECNR	(PLGRP)	Assumption
Plant Group Gas Region	Numeric	ECGR	(PLGRP)	Assumption
Renewable Group Ownership Type	Numeric	EHFOWN	(REN)	Assumption
Renewable Group Census Region	Numeric	EHCR	(REN)	Assumption
Renewable Group NEMS Region	Numeric	EHNR	(REN)	Assumption
Name of Plant Types	Alpha	ENPGRP	(DSP)	Assumption
Name of Renewable Plant Types	Alpha	ENHGRP	(RENTP)	Assumption
Name of Time of Day/Season Groups	Alpha	ELNMGRP	(DAY)	Assumption
Filler (Left Over)	Spaces	Unused bytes in DISPIN common		

Notes:

VS subscript values = 1 through 60 (Vertical Slices)
SEASON subscript values = 1 through 6 (6 seasons)
REN subscript values = 1 through 120 (Renewable Groups)
PLGRP subscript values = 1 through 300 (Plant Groups)
FPP subscript values = 1 through 4 (ECP Fuels per Plant)
DSP subscript values = 1 through 16 (Dispatchable Capacity Types)
SO2 subscript values = 1 through 2 (SO2 Compliance Groups)
DAY subscript values = 1 through 18 (Season/Time of Day Groups)
HR subscript values = 1 through 32 (Segments in each Season/Time of Day Group)
FRG subscript values = 1 through 3 (Supply/Reporting Regions per Fuel Type)
RENTP subscript values = 1 through 8 (Renewable Types)
CGRP subscript values = 1 (Compliance Groups per Plant Group)

Each record represents 1 region/year of data.

OE-411: DOE Form OE-411, "Coordinated Bulk Power Supply Program Report".
F860 - "Annual Electric Generator Report"
F867 - "Annual Nonutility Power Producer Report"
F767 - "Steam-Electric Plant Operation and Design Report"

LRECL = 16384
ACCESS = DIRECT
Filename = CN6005.PRJ.@.UTIL.INPTDAF.scenario.datekey

Common = CN6005.PRJ.NEMS.COMMON.PDS.datekey(DISPIN)
NEMS use = Output from beginning of EMM,
Input to EFD module of EMM

A.4 Inputs from Other Modules

TABLE A-17: COGEN Common DESCRIPTION

All 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
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)				
CGENDQ	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 13 (NEMS Regions)
YR subscript values = 1 through 29 (1990-2015, 2020, 2025, 2030)
FUEL subscript values = 1 through 4 (Fuel types,1=coal,2=oil,3=gas,4=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)

Common = CN6005.PRJ.NEMS.COMMON.PDS.datekey(COGEN)

Table A-18: WRENEW Common Description

Description	Variable	Indices	Source
TOTAL NUMBER OF SOLAR SUBPERIODS	MNUMSO		RFM
TOTAL NUMBER OF WIND SUBPERIODS	MNUMWI		RFM
TOTAL NUMBER OF WIND CLASSES	MNUMCL		RFM
# OF RENEWABLE TECHNOLOGIES	WNTECH		RFM
TOTAL # OF WORDS IN THIS COMMON	WRSIZE		RFM
UTIL HYDRO GENER CAPACITY	WCAHYEL	(MNUMNR,MNUMYR)	RFM
UTIL HYDRO CAPACITY FACTOR	WCFHYEL	(MNUMNR,MNUMYR)	RFM
UTIL HYDRO CAPITAL COST	WCCHYEL	(MNUMNR,MNUMYR)	RFM
UTIL HYDRO FIXED OP COST	WOCHYEL	(MNUMNR,MNUMYR)	RFM
UTIL HYDRO VAR OP COST	WVCHYEL	(MNUMNR,MNUMYR)	RFM
UTIL HYDRO HEAT RATE	WHRHYEL	(MNUMNR,MNUMYR)	RFM
UTIL HYDRO UNIT LIFE	WLIHYEL		RFM
UTIL FLASH GEOTH GENER CAPACITY	WCAGFEL	(MNUMNR,MNUMYR)	RFM
UTIL FLASH GEOTH CAPACITY FACTOR	WCFGFEL	(MNUMNR,MNUMYR)	RFM
UTIL FLASH GEOTH CAPITAL COST	WCCGFEL	(MNUMNR,MNUMYR)	RFM
UTIL FLASH GEOTH FIXED OP COST	WOCGFEL	(MNUMNR,MNUMYR)	RFM
UTIL FLASH GEOTH VAR OP COSTh	WVCGFEL	(MNUMNR,MNUMYR)	RFM
UTIL FLASH GEOTH HEAT RATE	WHRGFEL	(MNUMNR,MNUMYR)	RFM
UTIL FLASH GEOTH UNIT LIFE	WLIGFEL		RFM
UTIL BINARY GEOTH GENER CAPACITY	WCAGBEL	(MNUMNR,MNUMYR)	RFM
UTIL BINARY GEOTH CAPACITY FACTOR	WCFGBEL	(MNUMNR,MNUMYR)	RFM
UTIL BINARY GEOTH CAPITAL COST	WCCGBEL	(MNUMNR,MNUMYR)	RFM
UTIL BINARY GEOTH FIXED OP COST	WOCGBEL	(MNUMNR,MNUMYR)	RFM
UTIL BINARY GEOTH VAR OP COST	WVCGBEL	(MNUMNR,MNUMYR)	RFM
UTIL BINARY GEOTH HEAT RATE	WHRGBEL	(MNUMNR,MNUMYR)	RFM
UTIL BINARY GEOTH UNIT LIFE	WLIGBEL		RFM
RESIDEN GEOTH CAP	WCAGERS	(MNUMCR,MNUMYR)	RFM
RESIDEN GEOTH CAP FACTOR	WCFGERS	(MNUMCR,MNUMYR)	RFM
RESIDEN GEOTH CAP COST	WCCGERS	(MNUMCR,MNUMYR)	RFM
RESIDEN GEOTH FIXED OP COST	WOCGERS	(MNUMCR,MNUMYR)	RFM
RESIDEN GEOTH VAR OP COST	WVCGERS	(MNUMCR,MNUMYR)	RFM
RESIDEN GEOTH HEAT RATE	WHRGERS	(MNUMCR,MNUMYR)	RFM
RESIDEN GEOTH LIFE	WLIGERS		RFM
COMMERC GEOTH CAP	WCAGECM	(MNUMCR,MNUMYR)	RFM
COMMERC GEOTH CAP FACTOR	WCFGECM	(MNUMCR,MNUMYR)	RFM
COMMERC GEOTH CAP COST	WCCGECM	(MNUMCR,MNUMYR)	RFM
COMMERC GEOTH FIXED OP COST	WOCGECM	(MNUMCR,MNUMYR)	RFM
COMMERC GEOTH VAR OP COST	WVCGECM	(MNUMCR,MNUMYR)	RFM
COMMERC GEOTH HEAT RATE	WHRGECM	(MNUMCR,MNUMYR)	RFM
COMMERC GEOTH LIFE YRS	WLIGECM		RFM
UTIL MSW GENER CAPACITY	WCAMSEL	(MNUMNR,MNUMYR)	RFM
UTIL MSW CAPACITY FACTOR	WCFMSEL	(MNUMNR,MNUMYR)	RFM
UTIL MSW CAPITAL COST	WCCMSEL	(MNUMNR,MNUMYR)	RFM
UTIL MSW FIXED OP COST	WOCMSEL	(MNUMNR,MNUMYR)	RFM
UTIL MSW VAR OP COST	WVCMSEL	(MNUMNR,MNUMYR)	RFM
UTIL MSW HEAT RATE	WHRMSEL	(MNUMNR,MNUMYR)	RFM
UTIL MSW HEAT CONT	WHCMSEL	(MNUMNR,MNUMYR)	RFM
UTIL MSW UNIT LIFE	WLIMSEL		RFM
COMMERC MSW CAP	WCAMSCM	(MNUMCR,MNUMYR)	RFM
COMMERC MSW CAP FACTOR	WCFMSCM	(MNUMCR,MNUMYR)	RFM
COMMERC MSW CAP COST	WCCMSCM	(MNUMCR,MNUMYR)	RFM
COMMERC MSW FIXED OP COST	WOCMSCM	(MNUMCR,MNUMYR)	RFM
COMMERC MSW VAR OP COST	WVCMSCM	(MNUMCR,MNUMYR)	RFM
COMMERC MSW HEAT RATE	WHRMSCM	(MNUMCR,MNUMYR)	RFM
COMMERC MSW HEAT CONT	WHCMSCM	(MNUMCR,MNUMYR)	RFM

COMMERC MSW LIFE	WLIMSCM		RFM
INDUST MSW CAP	WCAMSIN	(MNUMCR,MNUMYR)	RFM
INDUST MSW CAP FACTOR	WCFMSIN	(MNUMCR,MNUMYR)	RFM
INDUST MSW CAP COST	WCCMSIN	(MNUMCR,MNUMYR)	RFM
INDUST MSW FIXED OP COST	WOCMSIN	(MNUMCR,MNUMYR)	RFM
INDUST MSW VAR OP COST	WVCMSIN	(MNUMCR,MNUMYR)	RFM
INDUST MSW HEAT RATE	WHRMSIN	(MNUMCR,MNUMYR)	RFM
INDUST MSW HEAT CONT	WHCMSIN	(MNUMCR,MNUMYR)	RFM
INDUST MSW LIFE	WLIMSIN		RFM
UTIL WOOD GENER CAPACITY	WCABMEL	(MNUMNR,MNUMYR)	RFM
UTIL WOOD CAPACITY FACTOR	WCFBMEL	(MNUMNR,MNUMYR)	RFM
UTIL WOOD CAPITAL COST	WCCBMEL	(MNUMNR,MNUMYR)	RFM
UTIL WOOD FIXED OP COST	WOCBMEL	(MNUMNR,MNUMYR)	RFM
UTIL WOOD VAR OP COST	WVCBMEL	(MNUMNR,MNUMYR)	RFM
UTIL WOOD HEAT RATE	WHRBMEL	(MNUMNR,MNUMYR)	RFM
UTIL WOOD HEAT CONT	WHCBMEL	(MNUMNR,MNUMYR)	RFM
UTIL WOOD UNIT LIFE	WLIBMEL		RFM
RESIDEN WOOD CAP	WCABMRS	(MNUMCR,MNUMYR)	RFM
RESIDEN WOOD CAP FACTOR	WCFBMRS	(MNUMCR,MNUMYR)	RFM
RESIDEN WOOD CAP COST	WCCBMRS	(MNUMCR,MNUMYR)	RFM
RESIDEN WOOD FIXED OP COST	WOCBMRS	(MNUMCR,MNUMYR)	RFM
RESIDEN WOOD VAR OP COST	WVCBMRS	(MNUMCR,MNUMYR)	RFM
RESIDEN WOOD HEAT RATE	WHRBMRS	(MNUMCR,MNUMYR)	RFM
RESIDEN WOOD LIFE	WLIBMRS		RFM
COMMERC WOOD CAP	WCABMCM	(MNUMCR,MNUMYR)	RFM
COMMERC WOOD CAP FACTOR	WCFBMCM	(MNUMCR,MNUMYR)	RFM
COMMERC WOOD CAP COST	WCCBMCM	(MNUMCR,MNUMYR)	RFM
COMMERC WOOD FIXED OP COST	WOCBMCM	(MNUMCR,MNUMYR)	RFM
COMMERC WOOD VAR OP COST	WVCBMCM	(MNUMCR,MNUMYR)	RFM
COMMERC WOOD HEAT RATE	WHRBMCM	(MNUMCR,MNUMYR)	RFM
COMMERC WOOD LIFE	WLIBMCM		RFM
INDUST WOOD CAP	WCABMIN	(MNUMCR,MNUMYR)	RFM
INDUST WOOD CAP FACTOR	WCFBMIN	(MNUMCR,MNUMYR)	RFM
INDUST WOOD CAP COST	WCCBMIN	(MNUMCR,MNUMYR)	RFM
INDUST WOOD FIXED OP COST	WOCBMIN	(MNUMCR,MNUMYR)	RFM
INDUST WOOD VAR OP COST	WVCBMIN	(MNUMCR,MNUMYR)	RFM
INDUST WOOD HEAT RATE	WHRBMIN	(MNUMCR,MNUMYR)	RFM
INDUST WOOD LIFE	WLIBMIN		RFM
UTIL SOLAR TH GENER CAPACITY	WCASTEL	(MNUMNR,MNUMYR)	RFM
UTIL SOLAR TH CAPACITY FACTOR	WCFSTEL	(MNUMNR,MNUMYR)	RFM
UTIL SOLAR TH CAPITAL COST	WCCSTEL	(MNUMNR,MNUMYR)	RFM
UTIL SOLAR TH FIXED OP COST	WOCSTEL	(MNUMNR,MNUMYR)	RFM
UTIL SOLAR TH VAR OP COST	WVCSTEL	(MNUMNR,MNUMYR)	RFM
UTIL SOLAR TH HEAT RATE	WHRSTEL	(MNUMNR,MNUMYR)	RFM
UTIL SOLAR TH HEAT CONT	WHCSTEL	(MNUMNR,MNUMYR)	RFM
UTIL SOLAR TH UNIT LIFE	WLISTEL		RFM
RESIDEN SOL TH CAP	WCASWRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH CAP FACTOR	WCFSWRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH CAP COST	WCCSWRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH FIXED OP COST	WOCSWRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH VAR OP COST	WVCSWRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH HEAT RATE	WHRSWRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH LIFE	WLISWRS		RFM
RESIDEN SOL TH CAP	WCASSRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH CAP FACTOR	WCFSSRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH CAP COST	WCCSSRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH FIXED OP COST	WOCSSRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH VAR OP COST	WVCSSRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH HEAT RATE	WHRSSRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL TH LIFE	WLISSRS		RFM
COMMERC SOL TH CAP	WCASWCM	(MNUMCR,MNUMYR)	RFM

COMMERC SOL TH CAP FACTOR	WCFSWCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL TH CAP COST	WCCSWCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL TH FIXED OP COST	WOCSWCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL TH VAR OP COST	WVCSWCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL TH HEAT RATE	WHRSWCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL TH LIFE	WLISWCM		RFM
COMMERC SOL TH CAP	WCASSCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL TH CAP FACTOR	WCFSSCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL TH CAP COST	WCCSSCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL TH FIXED OP COST	WOCSSCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL TH VAR OP COST	WVCSSCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL TH HEAT RATE	WHRSSCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL TH LIFE	WLISSCM		RFM
UTIL PHOTOV GENER CAPACITY	WCAPVEL	(MNUMNR,MNUMYR)	RFM
UTIL PHOTOV CAPACITY FACTOR	WCFPVEL	(MNUMNR,MNUMYR)	RFM
UTIL PHOTOV CAPITAL COST	WCCPVEL	(MNUMNR,MNUMYR)	RFM
UTIL PHOTOV FIXED OP COST	WOCPVEL	(MNUMNR,MNUMYR)	RFM
UTIL PHOTOV VAR OP COST	WVCPVEL	(MNUMNR,MNUMYR)	RFM
UTIL PHOTOV HEAT RATE	WHRPVEL	(MNUMNR,MNUMYR)	RFM
UTIL PHOTOV HEAT CONT	WHCPVEL	(MNUMNR,MNUMYR)	RFM
UTIL PHOTOV UNIT LIFE	WLIPVEL		RFM
RESIDEN SOL PV CAP	WCAPVRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL PV CAP FACTOR	WCFPVRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL PV CAP COST	WCCPVRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL PV FIXED OP COST	WOCPVRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL PV VAR OP COST	WVCPVRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL PV HEAT RATE	WHRPVRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL PV HEAT CONT	WHCPVRS	(MNUMCR,MNUMYR)	RFM
RESIDEN SOL PV LIFE	WLIPVRS		RFM
COMMERC SOL PV CAP	WCAPVCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL PV CAP FACTOR	WCFPVCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL PV CAP COST	WCCPVCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL PV FIXED OP COST	WOCPVCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL PV VAR OP COST	WVCPVCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL PV HEAT RATE	WHRPVCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL PV HEAT CONT	WHCPVCM	(MNUMCR,MNUMYR)	RFM
COMMERC SOL PV LIFE	WLIPVCM		RFM
UTIL WIND GENER CAPACITY	WCAWIEL	(MNUMNR,MNUMYR)	RFM
UTIL WIND CAPACITY FACTOR	WCFWIEL	(MNUMNR,MNUMYR)	RFM
UTIL WIND CAPITAL COST	WCCWIEL	(MNUMNR,MNUMYR)	RFM
UTIL WIND FIXED OP COST	WOCWIEL	(MNUMNR,MNUMYR)	RFM
UTIL WIND VAR OP COST	WVCWIEL	(MNUMNR,MNUMYR)	RFM
UTIL WIND HEAT RATE	WHRWIEL	(MNUMNR,MNUMYR)	RFM
UTIL WIND HEAT CONT	WHCWIEL	(MNUMNR,MNUMYR)	RFM
UTIL WIND UNIT LIFE	WLIWIEL		RFM
ETHANOL PRICE/STEP	WPETOH		RFM
ETHANOL QUAN/STEP	WQETOH		RFM
UTIL EMISSIONS FROM MSW	WEMMSEL	(MNPOLLUT,MNUMYR)	RFM
UTIL EMISSIONS FROM BIOMASS	WEMBMEL	(MNPOLLUT,MNUMYR)	RFM
UTIL EMISS FROM GEOTH FLASH	WEMGFEL	(MNPOLLUT,MNUMYR)	RFM
Year Available	WCAV	(WNTECH)	RFM
SUBSIDY	WCSU	(WNTECH,MNUMYR)	RFM
SUBSIDY	WCSI	(WNTECH,MNUMYR)	RFM
Construction Lead Time	WCLT	(WNTECH)	RFM
Percent Constructed	WCPC	(WNTECH8)	RFM
WIND PLANNED OUTAGE	WPOWIEL	(MNUMYR)	RFM
WIND CAPACITY CREDIT	WCRWIEL	(MNUMNR,MNUMYR)	RFM
AVAIL WIND CAPACITY	WSCWIEL	(MNUMNR,MNUMYR,MNUMC	RFM
WIND CAP FACTOR	WSFWIEL		RFM
SOLAR THERMAL SUPPLY SHAPE	WSSSTEL	(MNUMNR,MNUMYR,MNUMSO)	RFM
PHOTOVOLTAICS SUPPLY SHAPE	WSSPVEL	(MNUMNR,MNUMYR,MNUMSO)	RFM

MSW ELECTRICITY FOR INDUSTRIES	WQCMSINL (44,MNUMYR)	RFM
MSW STEAM FOR INDUSTRIES	WQCMSINT (44,MNUMYR)	RFM

Table A-19: Control Common Block 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
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

A.5 Output/Work Files

TABLE A-20: ETT$TMP DAF FILE DESCRIPTION

This file has the same format as the ETTDEM DAF input file.

Field	Units	Variable Name
Net Interregional Electricity Flows	GW	UEITAJ(SEASON,RGN)
Canadian Builds	GW	UCANBLD(RGN)
Transmission & Distrib. Loss Factor	Numeric	UQTDLS(RGN)
Max Summer Import Constraint	GW	URNCSI(RGN)
Max Summer Export Constraint	GW	URNCST(RGN)
Max Winter Export Constraint	GW	URNCWT(RGN)
Max Winter Import Constraint	GW	URNCWI(RGN)
Firm Power Sales (Net)	MWH	ZTDMMF(RGN)
Firm Power Sales (Gross)	MWH	ZTEXMF(RGN)
Firm Power Sales (Net)	MM$	ZTDMDF(RGN)
Firm Power Sales (Gross)	MM$	ZTEXDF(RGN)
International Firm Power Imports	MWH	ZTIMPF(RGN)
International Firm Power Imports	MM$	ZTIMPD(RGN)
International Firm Power Exports	MM$	ZTEXPD(RGN)
International Firm Power Exports	MWH	ZTEXPF(RGN)
Firm Power Available(Canadian Supply)	MW	UCI$FMW(STEP,RGN)
Peak Power Available(Canadian Supply)	MW	UCI$PMW(STEP,RGN)
Capacity Factor(Canadian Supply)	Numeric	UCI$CF(STEP,RGN)
Variable Cost (Canadian Supply)	Mills/Kwh	UCI$CST(STEP,RGN)
Canadian Export Rgn (Can. Supply)	Numeric	UCI$CRG(STEP,RGN)
Filler (Left Over)	Spaces	Unused bytes in DISPET3 common

Notes: RGN subscript values = 1 through 16 (NEMS Rgns 1-13)
STEP subscript values = 1 and 2 (2 steps)
SEASON subscript values = 1 through 6 (6 seasons)
Each record represents 1 year of data.

LRECL = 2048
ACCESS = DIRECT
Filename = CN6005.PRJ.@.UTIL.ETT$TMP.scenario.datekey
Common = CN6005.PRJ.NEMS.COMMON.PDS.datekey(DISPETT)
NEMS use = Output/Work file in EMM

Table A-21: DISPUSE Common Block Description

Description	Variable	Indices	Units
Y-INT&SLOPE CURRENT CUT LINE	ESLCUT	(2)	Numeric
Y VALUES OF Ssnal LOAD CURVE	ETYVAL	(EFD$MVS)	Numeric
X VALUES OF Ssnal LOAD CURVE	ETXVAL	(EFD$MVS)	Numeric
AREA IN EACH VERTICAL SLICE	ETAREA	(EFD$MVS)	Numeric
TOT LOAD&CUM AREA UND CUT LNE	EQLOAD	(2)	Numeric
AVL CAP/SSNAL PER NET OF PMR	ECACAP	(EFD$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$OWN)	trills
FUEL PRC FR PREVIOUS ITR -1	WPFUEL	(EFDNFL,EFDMFRG)	cents/mmBtu
FUEL PRC FR PREVIOUS ITR -2	XPFUEL	(EFDNFL,EFDMFRG)	cents/mmBtu
FUEL CONS BY NERC/OWNER	UQFCONN	(EFD$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$NFL,MNUMNR)	lbs/MMbtu
# POINTS DEFINING LOAD CURVE	ETNVCT		Numeric
TEST VAR(LOAD MET=1,ELSE=0)	EIDCHK		Numeric
# HOR SLICES REQ TO MEET LOAD	ECDSPN		Numeric
MERIT ORD MAP (1=MOST ECON)	ECTYP	(EFD$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 A-22: OUT DAF FILE DESCRIPTION

The OUTDAF file (loaded through the DISPOUT common block) stores EMM output information with each record containing information by region and year. The information is loaded into the DISPOUT by region and year and in turn, loads the information in the OUTDAF file (i.e., DISPOUT is overwritten for each region and year).

Description	Units	Variable Name
Variable O&M	MM$	ERTOM(OWN)
Reserve Margin Achieved	Numeric	EEMRM
Total Fuel Cost	MM$	ERTFL(OWN)
Total SO2 Allowances	Tons	ETALLW
Total SO2 Emissions	Tons	ETSO2
Total NOX Emissions	Tons	ETNOX
Total CO2 Emissions	Tons	ETCO2
Total Car Emissions	Tons	ETCAR
Total CO1 Emissions	Tons	ETCO1
Total VOC Emissions	Tons	ETVOC
Total Generation	GWH	ETGEN
Generation by NUGS for Own Use	GWH	EWGOWN
EWG -Rev. fr Utl	MM$	EWGREV
EWG Fixed $ Compont	MM$	EWGFIX
Commercial Cogen - Rev. fr Utl	MM$	EWGRCC
Industrial Cogen - Rev. fr Utl	MM$	EWGRIC
NUGS/Renewables - Rev. fr Utl	MM$	EWGRNW
SO2 Allowances by Compliance Group	Tons	EGALLW(SO2)
SO2 Penalty Cost by Compliance Group	$/Ton	EGPSO2(SO2)
SO2 Emissions by Compliance Group	Tons	EGSO2(SO2)
Summer Capacity (End-Year)	GW	ECSCAP(DSP,VIN,OWN)
Cum. Retirements (End-Year)		ECSRET(DSP,OWN)
Variable O&M by Plant Type	MM$	ERPOM(DSP)
Fuel Cost by Plant Type	MM$	ERPFL(DSP)
Generation by Plant Type	GWH	EQPGN(DSP,OWN)
Avg. Annual Capacity by Plant Type	GW	EQPCP(DSP)
Fuel Consumption by Plant Type	MMM Btu	EQPFL(DSP)
SO2 Emissions by Plant Type	Tons	EQPSO2(DSP)
NOX Emissions by Plant Type	Tons	EQPNOX(DSP)
CO2 Emissions by Plant Type	Tons	EQPCO2(DSP)
Fuel Cost by Fuel Type	MM$	ERFFL(NFL)
Generation by Fuel Type	GWH	EQFGN(NFL,OWN)
Fuel Consumption by Fuel Type	MMM Btu	EQFFL(NFL,OWN)
SO2 Emissions by Fuel Type	Tons	EQFSO2(NFL)
NOX Emissions by Fuel Type	Tons	EQFNOX(NFL)
CO2 Emissions by Fuel Type	Tons	EQFCO2(NFL)
Avg. Fuel Price by Fuel Type	$/kwh	EPFUEL(NFL)
Avg. SO2 Content by Fuel Type	lbs/MMBtu	EFRSO2(NFL)
Avg. NOX Content by Fuel Type	lbs/MMBtu	EFRNOX(NFL)
Avg. CO2 Content by Fuel Type	lbs/MMBtu	EFRCO2(NFL)
Avg. Btu Content by Fuel Type	lbs/MMbtu	EFHCNT(NFL)
Summer Capacity (End-Year)	GW	EHSCAP(RNW,VIN,OWN)
Cum. Retirements (End-Year)	GW	EHSRET(RNW,OWN)
Generation by Renewables Technology	GWH	EQHGN(RNW,OWN)
Var. O&M by Renewables Technology	MM$	ERHOM(RNW,OWN)
Avg. Annual Cap. by Renewables Technology	GW	EQHCP(RNW)
Generation by Plant Type and Season	GWH	EGENPS(DSP,SEASON)
Capacity Req.?? by Plant Type and Season	GW	EAVLPS(DSP,SEASON)
Capacity Avail. by Plant Type and Season	GW	ECAPPS(DSP,SEASON)
Generation by Ren. Technology and Season	GWH	EGENHS(RNW,SEASON)
Capacity by Ren. Technology and Season	GW	ECAPHS(RNW,SEASON)

Peak Requirement by Season	GW	EPEAK(SEASON)
Domestic Firm Power Sales	MWH	ETDMMF
Domestic Economy Sales	MWH	ETDMME
Domestic Firm Power Sales	MM$	ETDMDF
Domestic Economy Sales	MM$	ETDMDE
Imports - Firm MWH	ETIMPF	
Imports - Economy	MWH	ETIMPE
Import Revenues	MM$	ETIMPD
Exports - Firm MWH	ETEXPF	
Exports - Economy	MWH	ETEXPE
Domestic Economy Trade Profit	MM$	ETDMPE
Exports - Revenues	MM$	ETEXPD
Number of SO2 Compliance Groups	Numeric	ENSO2
Number of Fuel Types	Numeric	ENFLTP
Name for Each Fuel Type	Alpha	ENMFL(NFL)
Filler (Left Over)	Spaces	Unused bytes in DISPOUT Common

Table A-23: UEFDOUT Common Block

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
BIT COAL CONVERGENCE FLAG	FBTELNR	(NDREG)	Numeric
SUB COAL CONVERGENCE FLAG	FSTELNR	(NDREG)	Numeric
LIG COAL CONVERGENCE FLAG	FLTELNR	(NDREG-1)	Numeric
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

Table A-24: UETTOUT Common Block

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 (in the &6005PRJ.NEMS.FORTRN.UETT. scenario.datekey code), ELEFD and ELDISP (in the &6005PRJ. NEMS.FORTRN.UEFD.scenario.datekey). See above parameter listing for a description of the indices of the arrays.

A.6 Variable Cross Reference Tables

Table A-25: Alphabetical Variable Listing

This table contains an alphabetical listing of all the variables in the EFD source code. Beneath each variable/parameter name is the name of the subroutines in which this variable is used.

VARIABLE/PARAMETER= ANINT
ELSO2L

VARIABLE/PARAMETER= AREAIT
ELDISP
ELALOC

VARIABLE/PARAMETER= AREANT
ELDISP
ELALOC
ELLOAD

VARIABLE/PARAMETER= AREATI
ELDISP

VARIABLE/PARAMETER= AREATR
ELDISP

VARIABLE/PARAMETER= AREATT
ELDISP
ELALOC

VARIABLE/PARAMETER= AREATV
ELDISP

VARIABLE/PARAMETER= AREATX
ELDISP

VARIABLE/PARAMETER= AREITV
ELDISP

VARIABLE/PARAMETER= AREITX
ELDISP

VARIABLE/PARAMETER= AVAIL
ELPLNM

VARIABLE/PARAMETER= A_CRV
ELRNEW

VARIABLE/PARAMETER= A_MAX
ELRNEW

VARIABLE/PARAMETER= A_MIN
ELRNEW

VARIABLE/PARAMETER= CAP
ELPLNM

VARIABLE/PARAMETER= CAPAVL

ELALOC

VARIABLE/PARAMETER= CAPSW
ELALOC

VARIABLE/PARAMETER= CAPTR
ELDISP

VARIABLE/PARAMETER= CAPTRI
ELDISP

VARIABLE/PARAMETER= CAPTRX
ELDISP

VARIABLE/PARAMETER= CAPTRY
ELDISP

VARIABLE/PARAMETER= CFLTMP
ELFSHR

VARIABLE/PARAMETER= COMTMP
ELFSHR

VARIABLE/PARAMETER= COST
ELFSHR

VARIABLE/PARAMETER= COSTFL
ELFSHR

VARIABLE/PARAMETER= COSTOM
ELFSHR

VARIABLE/PARAMETER= COSTSO2
ELFSHR

VARIABLE/PARAMETER= CPIVOT
ELALOC

VARIABLE/PARAMETER= CSO2TMP
ELFSHR

VARIABLE/PARAMETER= CSTTMP
ELFSHR

VARIABLE/PARAMETER= CST_FL
ELMRIT
ELFSHR

VARIABLE/PARAMETER= CST_OM
ELMRIT
ELFSHR

VARIABLE/PARAMETER= CST_SO2
ELMRIT
ELFSHR

VARIABLE/PARAMETER= CST_TOT
ELMRIT
ELFSHR

VARIABLE/PARAMETER= CUMAREA
ELDISP

VARIABLE/PARAMETER= CUMAREI
ELDISP

VARIABLE/PARAMETER= CURITR
ELEFD
ELSO2L

VARIABLE/PARAMETER= CUT
ELLOAD

VARIABLE/PARAMETER= C_1
ELRNEW

VARIABLE/PARAMETER= C_2
ELRNEW

VARIABLE/PARAMETER= C_DN
ELRNEW

VARIABLE/PARAMETER= C_UP
ELRNEW

VARIABLE/PARAMETER= DBLE
ELDISP
ELALOC
ELGETY
ELFSHR
ELPLNM
ELRNEW

VARIABLE/PARAMETER= DC0
ELSO2L

VARIABLE/PARAMETER= DEMAND
ELPLNM

VARIABLE/PARAMETER= DENOM
ELDISP

VARIABLE/PARAMETER= DL0
ELSO2L

VARIABLE/PARAMETER= DN0
ELSO2L

VARIABLE/PARAMETER= DNC
ELSO2L

VARIABLE/PARAMETER= DNTRG1
ELALOC

VARIABLE/PARAMETER= DNTRG2
ELALOC

VARIABLE/PARAMETER= DNTRG3
ELALOC

VARIABLE/PARAMETER= DNXTRG
ELALOC

VARIABLE/PARAMETER= DOWN
ELSO2L

VARIABLE/PARAMETER= EAVLPS
ELDISP

VARIABLE/PARAMETER= ECACAP
ELDISP
ELALOC

VARIABLE/PARAMETER= ECALLW
ELDISP

VARIABLE/PARAMETER= ECAPHS
ELDISP
ELRNEW

VARIABLE/PARAMETER= ECAPPS
ELDISP
ELCOST

VARIABLE/PARAMETER= ECASTS
ELDISP
ELMRIT
ELALOC
ELCOST
ELFSHR

VARIABLE/PARAMETER= ECCAP
ELDISP
ELFSHR
ELPLNM

VARIABLE/PARAMETER= ECCFBD
ELALOC

VARIABLE/PARAMETER= ECCOPM
ELDISP
ELPLNM

VARIABLE/PARAMETER= ECCR
ELCOST

VARIABLE/PARAMETER= ECDSPC
ELALOC
ELCOST

VARIABLE/PARAMETER= ECDSPE
ELALOC
ELCOST

VARIABLE/PARAMETER= ECDSPN
ELDISP
ELALOC
ELLOAD
ELCOST

VARIABLE/PARAMETER= ECDSPP

ELALOC

VARIABLE/PARAMETER= ECDSPT
ELDISP
ELALOC
ELCOST

VARIABLE/PARAMETER= ECFLRG
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= ECFLTP
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= ECFOR
ELDISP
ELALOC

VARIABLE/PARAMETER= ECFOWN
ELCOST

VARIABLE/PARAMETER= ECFSHR
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= ECGR
ELCOST

VARIABLE/PARAMETER= ECHTRT
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= ECLFR
ELDISP
ELALOC

VARIABLE/PARAMETER= ECMFSH
ELFSHR

VARIABLE/PARAMETER= ECMXCP
ELDISP

VARIABLE/PARAMETER= ECNTP
ELDISP
ELMRIT
ELALOC
ELLOAD
ELFSHR
ELPLNM

VARIABLE/PARAMETER= ECOMR
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= ECP$FPP
ELCOST

VARIABLE/PARAMETER= ECP$NFL
ELDISP

VARIABLE/PARAMETER= ECPMR
ELDISP
ELPLNM

VARIABLE/PARAMETER= ECSCRB
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= ECTYP
ELMRIT
ELALOC
ELPLNM

VARIABLE/PARAMETER= ECVCST
ELMRIT

VARIABLE/PARAMETER= EEITAJ
ELDISP
ELPLNM

VARIABLE/PARAMETER= EEMRM
ELPLNM

VARIABLE/PARAMETER= EENSP
ELDISP
ELFSHR
ELPLNM

VARIABLE/PARAMETER= EESSHR
ELFSHR

VARIABLE/PARAMETER= EETIME
ELDISP
ELCOST
ELPLNM
ELRNEW

VARIABLE/PARAMETER= EFACTR
ELDISP
ELMRIT
ELALOC
ELCOST
ELFSHR
ELPLNM
ELRNEW

VARIABLE/PARAMETER= EFD$MFRG
ELEFD
ELDISP
ELCOST

VARIABLE/PARAMETER= EFD$MHS
ELDISP

ELMRIT
ELALOC

VARIABLE/PARAMETER= EFD$MVS
ELDISP

VARIABLE/PARAMETER= EFD$NFL
ELDISP

VARIABLE/PARAMETER= EFD$OWN
ELDISP

VARIABLE/PARAMETER= EFDOK
ELEFD

VARIABLE/PARAMETER= EFHCNT
ELDISP
ELCOST

VARIABLE/PARAMETER= EFRCO2
ELDISP

VARIABLE/PARAMETER= EFRNOX
ELDISP

VARIABLE/PARAMETER= EFRSO2
ELDISP

VARIABLE/PARAMETER= EGALLW
ELDISP
ELSO2F
ELSO2N

VARIABLE/PARAMETER= EGENHS
ELDISP
ELRNEW

VARIABLE/PARAMETER= EGENPS
ELDISP
ELCOST

VARIABLE/PARAMETER= EGNVCT
ELDISP

VARIABLE/PARAMETER= EGPSO2
ELSO2F

VARIABLE/PARAMETER= EGSO2
ELDISP
ELCOST
ELSO2F
ELSO2N

VARIABLE/PARAMETER= EGXVAL
ELDISP

VARIABLE/PARAMETER= EGYVAL
ELDISP

VARIABLE/PARAMETER= EHCAP
ELDISP

ELPLNM
ELRNEW

VARIABLE/PARAMETER= EHCR
ELRNEW

VARIABLE/PARAMETER= EHFOWN
ELRNEW

VARIABLE/PARAMETER= EHHYCF
ELRNEW

VARIABLE/PARAMETER= EHHYTP
ELDISP
ELRNEW

VARIABLE/PARAMETER= EHNR
ELRNEW

VARIABLE/PARAMETER= EHNTP
ELDISP
ELPLNM
ELRNEW

VARIABLE/PARAMETER= EHVOMR
ELRNEW

VARIABLE/PARAMETER= EIDCHK
ELALOC
ELLOAD

VARIABLE/PARAMETER= EIFPLT
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= EIHGRP
ELEFD
ELDISP

VARIABLE/PARAMETER= EIMCG
ELDISP
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= EIPGRP
ELEFD
ELDISP
ELRNEW

VARIABLE/PARAMETER= EISO2
ELDISP
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= ELNVCT
ELDISP

VARIABLE/PARAMETER= ELXVAL

ELDISP

VARIABLE/PARAMETER= ELYVAL
ELDISP
ELPLNM

VARIABLE/PARAMETER= ENFLTP
ELEFD
ELDISP

VARIABLE/PARAMETER= ENSO2
ELDISP
ELSO2F
ELSO2N

VARIABLE/PARAMETER= EPCRMP
ELDISP
ELCOST

VARIABLE/PARAMETER= EPEAK
ELDISP

VARIABLE/PARAMETER= EPFLRG
ELDISP
ELCOST

VARIABLE/PARAMETER= EPFMAP
ELDISP
ELCOST

VARIABLE/PARAMETER= EPFTOL
ELFSHR

VARIABLE/PARAMETER= EPFUEL
ELDISP

VARIABLE/PARAMETER= EPSO2
ELMRIT
ELFSHR
ELSO2F

VARIABLE/PARAMETER= EQFCO2
ELDISP
ELCOST

VARIABLE/PARAMETER= EQFFL
ELDISP
ELCOST

VARIABLE/PARAMETER= EQFGN
ELDISP
ELCOST

VARIABLE/PARAMETER= EQFNOX
ELDISP
ELCOST

VARIABLE/PARAMETER= EQFSO2
ELDISP
ELCOST

VARIABLE/PARAMETER= EQHCP
ELDISP

VARIABLE/PARAMETER= EQHGN
ELDISP
ELRNEW

VARIABLE/PARAMETER= EQLOAD
ELDISP
ELALOC
ELLOAD

VARIABLE/PARAMETER= EQPCO2
ELDISP
ELCOST

VARIABLE/PARAMETER= EQPCP
ELDISP

VARIABLE/PARAMETER= EQPFL
ELDISP
ELCOST

VARIABLE/PARAMETER= EQPGN
ELDISP
ELCOST

VARIABLE/PARAMETER= EQPNOX
ELDISP
ELCOST

VARIABLE/PARAMETER= EQPSO2
ELDISP
ELCOST

VARIABLE/PARAMETER= ERFFL
ELDISP
ELCOST

VARIABLE/PARAMETER= ERHOM
ELDISP
ELRNEW

VARIABLE/PARAMETER= ERPFL
ELDISP
ELCOST

VARIABLE/PARAMETER= ERPOM
ELDISP
ELCOST

VARIABLE/PARAMETER= ERTFL
ELDISP
ELCOST

VARIABLE/PARAMETER= ERTOM
ELDISP
ELCOST

VARIABLE/PARAMETER= ERYVAL
ELDISP

VARIABLE/PARAMETER= ESLCUT
ELALOC
ELLOAD

VARIABLE/PARAMETER= ETALLW
ELDISP

VARIABLE/PARAMETER= ETAREA
ELDISP
ELLOAD

VARIABLE/PARAMETER= ETCAR
ELDISP
ELCOST

VARIABLE/PARAMETER= ETCO1
ELDISP
ELCOST

VARIABLE/PARAMETER= ETCO2
ELDISP
ELCOST

VARIABLE/PARAMETER= ETDSPN
ELCOST

VARIABLE/PARAMETER= ETDSPT
ELCOST

VARIABLE/PARAMETER= ETEXPE
ELDISP
ELPLNM

VARIABLE/PARAMETER= ETFSHR
ELCOST

VARIABLE/PARAMETER= ETGEN
ELDISP
ELCOST

VARIABLE/PARAMETER= ETIMPE
ELDISP
ELPLNM

VARIABLE/PARAMETER= ETNOX
ELDISP
ELCOST

VARIABLE/PARAMETER= ETNVCT
ELDISP
ELALOC
ELLOAD
ELGETY
ELGTXY
ELRNEW

VARIABLE/PARAMETER= ETSO2
ELDISP
ELCOST

VARIABLE/PARAMETER= ETT$MTG
ELDISP

VARIABLE/PARAMETER= ETVOC
ELDISP
ELCOST

VARIABLE/PARAMETER= ETXVAL
ELDISP
ELALOC
ELLOAD
ELGETY
ELGTXY
ELRNEW

VARIABLE/PARAMETER= ETYVAL
ELDISP
ELALOC
ELLOAD
ELGETY
ELGTXY
ELRNEW

VARIABLE/PARAMETER= EXMAP
ELDISP

VARIABLE/PARAMETER= EXPANN
ELDISP
ELPLNM

VARIABLE/PARAMETER= EXPCI
ELDISP

VARIABLE/PARAMETER= EXTMP
ELDISP

VARIABLE/PARAMETER= FCRL
ELEFD
ELDISP

VARIABLE/PARAMETER= FLAGSO2
ELEFD

VARIABLE/PARAMETER= FRAC
ELSO2L

VARIABLE/PARAMETER= FRAC2
ELSO2L

VARIABLE/PARAMETER= FSHR
ELFSHR

VARIABLE/PARAMETER= FUEL
ELCOST

VARIABLE/PARAMETER= FULLYR
ELEFD
ELPLNM

VARIABLE/PARAMETER= F_DN
ELRNEW

VARIABLE/PARAMETER= F_UP
ELRNEW

VARIABLE/PARAMETER= GEN
ELCOST

VARIABLE/PARAMETER= HN
ELLOAD

VARIABLE/PARAMETER= I
ELDISP
ELMRIT
ELALOC
ELLOAD
ELCOST
ELGETY
ELGTXY
ELFSHR
ELSO2F
ELSO2N
ELSO2L

VARIABLE/PARAMETER= IABOVE
ELLOAD
ELGTXY

VARIABLE/PARAMETER= ICAP
ELDISP
ELALOC

VARIABLE/PARAMETER= ICCAP
ELALOC

VARIABLE/PARAMETER= ICHK
ELALOC

VARIABLE/PARAMETER= ICNT
ELFSHR

VARIABLE/PARAMETER= ICNVG
ELEFD
ELSO2L

VARIABLE/PARAMETER= ICR
ELCOST
ELRNEW

VARIABLE/PARAMETER= ICTRG
ELALOC

VARIABLE/PARAMETER= IDUAL
ELCOST
ELFSHR

VARIABLE/PARAMETER= IE

ELDISP
ELLOAD
ELCOST

VARIABLE/PARAMETER= IE1
ELDISP
ELLOAD

VARIABLE/PARAMETER= IE2
ELDISP
ELALOC
ELLOAD

VARIABLE/PARAMETER= IE3
ELDISP

VARIABLE/PARAMETER= IE4
ELDISP

VARIABLE/PARAMETER= IECP
ELCOST

VARIABLE/PARAMETER= IFCAP
ELALOC

VARIABLE/PARAMETER= IFL
ELEFD
ELDISP

VARIABLE/PARAMETER= IFLRG
ELEFD
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= IFLTP
ELCOST

VARIABLE/PARAMETER= IFOWN
ELCOST
ELRNEW

VARIABLE/PARAMETER= IFP
ELCOST

VARIABLE/PARAMETER= IFRST
ELGETY
ELGTXY

VARIABLE/PARAMETER= IFUEL
ELMRIT
ELFSHR

VARIABLE/PARAMETER= IGR
ELCOST

VARIABLE/PARAMETER= ILST
ELMRIT

VARIABLE/PARAMETER= IMCG
ELCOST

VARIABLE/PARAMETER= IMMAP
ELDISP

VARIABLE/PARAMETER= IMPANN
ELDISP
ELPLNM

VARIABLE/PARAMETER= IMPCI
ELDISP

VARIABLE/PARAMETER= IMTMP
ELDISP

VARIABLE/PARAMETER= INGRG
ELFSHR

VARIABLE/PARAMETER= INR
ELCOST
ELRNEW

VARIABLE/PARAMETER= INTNUM
ELLOAD

VARIABLE/PARAMETER= INTRUP
ELDISP
ELPLNM

VARIABLE/PARAMETER= IOLRG
ELFSHR

VARIABLE/PARAMETER= IOUT
ELGETY
ELGTXY

VARIABLE/PARAMETER= IOWN
ELDISP

VARIABLE/PARAMETER= IPGRP
ELDISP
ELCOST
ELFSHR

VARIABLE/PARAMETER= IPLNT
ELPLNM

VARIABLE/PARAMETER= IPTYP
ELMRIT

VARIABLE/PARAMETER= IR
ELFSHR

VARIABLE/PARAMETER= IREC
ELDISP

VARIABLE/PARAMETER= IRG
ELEFD
ELDISP

ELSO2N
ELPLNM
ELRNEW

VARIABLE/PARAMETER= IRNEW
ELPLNM

VARIABLE/PARAMETER= IRNW
ELDISP
ELRNEW

VARIABLE/PARAMETER= IRPTSW
ELALOC

VARIABLE/PARAMETER= IRS
ELFSHR

VARIABLE/PARAMETER= IRT
ELFSHR

VARIABLE/PARAMETER= ISO2
ELDISP
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= ISOL
ELEFD
ELDISP
ELSO2F
ELSO2N
ELSO2L

VARIABLE/PARAMETER= ISP
ELMRIT
ELCOST
ELFSHR
ELPLNM
ELRNEW

VARIABLE/PARAMETER= ISTRT
ELLOAD

VARIABLE/PARAMETER= ISTRT3
ELLOAD

VARIABLE/PARAMETER= IT
ELALOC

VARIABLE/PARAMETER= ITEMP
ELMRIT
ELALOC

VARIABLE/PARAMETER= IVAL
ELALOC

VARIABLE/PARAMETER= IVCT
ELDISP
ELRNEW

VARIABLE/PARAMETER= IYR
ELEFD
ELDISP
ELPLNM
ELRNEW

VARIABLE/PARAMETER= I_DN
ELRNEW

VARIABLE/PARAMETER= I_UP
ELRNEW

VARIABLE/PARAMETER= I_VAL
ELRNEW

VARIABLE/PARAMETER= J
ELDISP
ELMRIT
ELALOC
ELCOST
ELFSHR

VARIABLE/PARAMETER= JCAP
ELDISP
ELALOC

VARIABLE/PARAMETER= JFRST
ELMRIT

VARIABLE/PARAMETER= JFST
ELALOC

VARIABLE/PARAMETER= JK
ELEFD

VARIABLE/PARAMETER= JPLNT
ELPLNM

VARIABLE/PARAMETER= JRG
ELDISP

VARIABLE/PARAMETER= JRNW
ELRNEW

VARIABLE/PARAMETER= JSP
ELFSHR
ELPLNM

VARIABLE/PARAMETER= JT
ELALOC

VARIABLE/PARAMETER= K
ELDISP
ELFSHR

VARIABLE/PARAMETER= KFOR
ELDISP
ELALOC

VARIABLE/PARAMETER= KHYCF

ELRNEW

VARIABLE/PARAMETER= KMXCP
ELDISP

VARIABLE/PARAMETER= KPMR
ELDISP
ELPLNM

VARIABLE/PARAMETER= KSCRB
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= KSP
ELPLNM

VARIABLE/PARAMETER= KTRG
ELALOC

VARIABLE/PARAMETER= MAX
ELDISP
ELMRIT
ELALOC
ELGETY
ELFSHR
ELSO2L
ELPLNM
ELRNEW

VARIABLE/PARAMETER= MAXOSHR
ELFSHR

VARIABLE/PARAMETER= MAXSHR
ELFSHR

VARIABLE/PARAMETER= MAX_AVL
ELPLNM

VARIABLE/PARAMETER= MAX_PK
ELPLNM

VARIABLE/PARAMETER= MIN
ELDISP
ELALOC
ELFSHR
ELSO2L
ELPLNM
ELRNEW

VARIABLE/PARAMETER= MINOSHR
ELFSHR

VARIABLE/PARAMETER= MINUS1
ELALOC

VARIABLE/PARAMETER= MNUMCR
ELEFD
ELDISP

VARIABLE/PARAMETER= MNUMNR

ELEFD

VARIABLE/PARAMETER= N
ELALOC
ELCOST

VARIABLE/PARAMETER= NFLRG
ELCOST

VARIABLE/PARAMETER= NGSHR
ELFSHR

VARIABLE/PARAMETER= NMTRGR
ELALOC

VARIABLE/PARAMETER= NPLNT
ELPLNM

VARIABLE/PARAMETER= NT
ELALOC

VARIABLE/PARAMETER= NTI
ELALOC

VARIABLE/PARAMETER= NTJ
ELALOC

VARIABLE/PARAMETER= NTRGOR
ELALOC

VARIABLE/PARAMETER= NXTTRG
ELALOC

VARIABLE/PARAMETER= OLSHR
ELFSHR

VARIABLE/PARAMETER= PC
ELSO2L

VARIABLE/PARAMETER= PDIF
ELFSHR

VARIABLE/PARAMETER= PEAK
ELPLNM

VARIABLE/PARAMETER= PFUEL
ELFSHR

VARIABLE/PARAMETER= PJUMP
ELSO2L

VARIABLE/PARAMETER= PL
ELSO2L

VARIABLE/PARAMETER= PMAX
ELFSHR

VARIABLE/PARAMETER= PMIN
ELFSHR

VARIABLE/PARAMETER= PN

ELSO2L

VARIABLE/PARAMETER= PRINT
ELCOST

VARIABLE/PARAMETER= PSHR
ELFSHR

VARIABLE/PARAMETER= PSO2
ELMRIT
ELFSHR

VARIABLE/PARAMETER= PTOL
ELSO2L

VARIABLE/PARAMETER= Q0
ELSO2L

VARIABLE/PARAMETER= QC
ELSO2L

VARIABLE/PARAMETER= QL
ELSO2L

VARIABLE/PARAMETER= QN
ELSO2L

VARIABLE/PARAMETER= R1
ELFSHR

VARIABLE/PARAMETER= R2
ELFSHR

VARIABLE/PARAMETER= REQIR
ELPLNM

VARIABLE/PARAMETER= RQ
ELPLNM

VARIABLE/PARAMETER= RSHR
ELFSHR

VARIABLE/PARAMETER= RSHRTAV
ELFSHR

VARIABLE/PARAMETER= RSPRCAV
ELFSHR

VARIABLE/PARAMETER= RSSHR
ELFSHR

VARIABLE/PARAMETER= RSSO2AV
ELFSHR

VARIABLE/PARAMETER= RSVOMAV
ELFSHR

VARIABLE/PARAMETER= RX
ELFSHR

VARIABLE/PARAMETER= R_AREA

ELRNEW

VARIABLE/PARAMETER= R_CAP
ELRNEW

VARIABLE/PARAMETER= S1
ELFSHR

VARIABLE/PARAMETER= S2
ELFSHR

VARIABLE/PARAMETER= SAREA
ELALOC
ELLOAD

VARIABLE/PARAMETER= SCHDLD
ELPLNM

VARIABLE/PARAMETER= SHGHT
ELALOC
ELLOAD

VARIABLE/PARAMETER= SLFR
ELALOC
ELLOAD

VARIABLE/PARAMETER= SLFR0
ELALOC

VARIABLE/PARAMETER= SLOPE
ELGTXY

VARIABLE/PARAMETER= SOLSW
ELALOC

VARIABLE/PARAMETER= SWGHT
ELFSHR

VARIABLE/PARAMETER= S_AREA
ELRNEW

VARIABLE/PARAMETER= S_CAP
ELRNEW

VARIABLE/PARAMETER= T2SHR
ELFSHR

VARIABLE/PARAMETER= TEMP
ELDISP
ELMRIT
ELCOST
ELFSHR
ELRNEW

VARIABLE/PARAMETER= TEMP2
ELFSHR

VARIABLE/PARAMETER= TFUEL
ELFSHR

VARIABLE/PARAMETER= TIYVAL

ELDISP
ELLOAD

VARIABLE/PARAMETER= TLSO2
ELSO2L

VARIABLE/PARAMETER= TOLRNC
ELALOC

VARIABLE/PARAMETER= TOTAL
ELPLNM

VARIABLE/PARAMETER= TOTAVL
ELPLNM

VARIABLE/PARAMETER= TOTGOIL
ELCOST

VARIABLE/PARAMETER= TOTHRS
ELDISP
ELPLNM

VARIABLE/PARAMETER= TQDFRHG
ELEFD
ELCOST

VARIABLE/PARAMETER= TQDFRLG
ELEFD
ELCOST

VARIABLE/PARAMETER= TQFFL
ELDISP

VARIABLE/PARAMETER= TRGCMAX
ELEFD
ELCOST

VARIABLE/PARAMETER= TRGCMIN
ELEFD
ELCOST

VARIABLE/PARAMETER= TRGCPAR
ELEFD
ELCOST

VARIABLE/PARAMETER= TRGSLP
ELALOC

VARIABLE/PARAMETER= TRIGER
ELALOC

VARIABLE/PARAMETER= TRNCSI
ELDISP

VARIABLE/PARAMETER= TRNCST
ELDISP
ELPLNM

VARIABLE/PARAMETER= TRNCWI
ELDISP

VARIABLE/PARAMETER= TRNCWT
ELDISP
ELPLNM

VARIABLE/PARAMETER= TRSSHR
ELFSHR

VARIABLE/PARAMETER= TSGCMAX
ELEFD
ELCOST

VARIABLE/PARAMETER= TSGCMIN
ELEFD
ELCOST

VARIABLE/PARAMETER= TSGCPAR
ELEFD
ELCOST

VARIABLE/PARAMETER= TSHR
ELFSHR

VARIABLE/PARAMETER= TSTSSN
ELPLNM

VARIABLE/PARAMETER= TTYVAL
ELDISP

VARIABLE/PARAMETER= TWGHT
ELFSHR

VARIABLE/PARAMETER= TWSHR
ELFSHR

VARIABLE/PARAMETER= T_AVL
ELPLNM

VARIABLE/PARAMETER= T_CAP
ELRNEW

VARIABLE/PARAMETER= T_DN
ELRNEW

VARIABLE/PARAMETER= UCASTS
ELCOST

VARIABLE/PARAMETER= UFHCNT
ELDISP
ELCOST

VARIABLE/PARAMETER= UFL$ECP
ELCOST

VARIABLE/PARAMETER= UFPTOL
ELFSHR

VARIABLE/PARAMETER= UFRASH
ELCOST

VARIABLE/PARAMETER= UFRCAR
ELCOST

VARIABLE/PARAMETER= UFRCO1
ELCOST

VARIABLE/PARAMETER= UFRCO2
ELDISP
ELCOST

VARIABLE/PARAMETER= UFRNOX
ELDISP
ELCOST

VARIABLE/PARAMETER= UFRSO2
ELDISP
ELMRIT
ELCOST

VARIABLE/PARAMETER= UFRVOC
ELCOST

VARIABLE/PARAMETER= UF_CRV
ELDISP

VARIABLE/PARAMETER= UF_DBG
ELEFD
ELPLNM

VARIABLE/PARAMETER= UF_RPT
ELEFD

VARIABLE/PARAMETER= UIALLW
ELSO2N
ELSO2L

VARIABLE/PARAMETER= UIGC
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= UIGF
ELMRIT
ELFSHR

VARIABLE/PARAMETER= UIRH
ELCOST
ELFSHR

VARIABLE/PARAMETER= UIRL
ELCOST
ELFSHR

VARIABLE/PARAMETER= UNFLRG
ELEFD
ELCOST

VARIABLE/PARAMETER= UNRGNS
ELEFD

VARIABLE/PARAMETER= UNSO2
ELEFD
ELSO2F

ELSO2L

VARIABLE/PARAMETER= UNTCOS
ELDISP
ELMRIT

VARIABLE/PARAMETER= UNTCST
ELMRIT

VARIABLE/PARAMETER= UP
ELSO2L

VARIABLE/PARAMETER= UPCSO2
ELSO2N
ELSO2L

VARIABLE/PARAMETER= UPFUEL
ELDISP
ELMRIT
ELCOST
ELFSHR

VARIABLE/PARAMETER= UPLSO2
ELSO2N
ELSO2L

VARIABLE/PARAMETER= UPNSO2
ELEFD
ELSO2F
ELSO2L

VARIABLE/PARAMETER= UPOLD
ELEFD

VARIABLE/PARAMETER= UQALLW
ELSO2N
ELSO2L

VARIABLE/PARAMETER= UQCSO2
ELSO2N
ELSO2L

VARIABLE/PARAMETER= UQFCONN
ELEFD
ELCOST

VARIABLE/PARAMETER= UQFGENC
ELEFD
ELCOST

VARIABLE/PARAMETER= UQFGENN
ELEFD
ELCOST

VARIABLE/PARAMETER= UQFSO2
ELDISP
ELCOST

VARIABLE/PARAMETER= UQFUEL
ELEFD
ELCOST

VARIABLE/PARAMETER= UQHGENC
ELEFD
ELRNEW

VARIABLE/PARAMETER= UQHGENN
ELEFD
ELRNEW

VARIABLE/PARAMETER= UQLSO2
ELSO2N
ELSO2L

VARIABLE/PARAMETER= UQNSO2
ELEFD
ELSO2N
ELSO2L

VARIABLE/PARAMETER= UQPGENC
ELEFD
ELCOST

VARIABLE/PARAMETER= UQPGENN
ELEFD
ELCOST

VARIABLE/PARAMETER= UQPSO2
ELSO2N
ELSO2L

VARIABLE/PARAMETER= URGCMAX
ELCOST
ELFSHR

VARIABLE/PARAMETER= URGCMIN
ELCOST
ELFSHR

VARIABLE/PARAMETER= URGCPAR
ELCOST
ELFSHR

VARIABLE/PARAMETER= USGCMAX
ELCOST
ELFSHR

VARIABLE/PARAMETER= USGCMIN
ELCOST
ELFSHR

VARIABLE/PARAMETER= USGCPAR
ELCOST
ELFSHR

VARIABLE/PARAMETER= USW_ETT
ELEFD
ELDISP
ELMRIT
ELALOC
ELLOAD

ELCOST
ELPLNM

VARIABLE/PARAMETER= USYEAR
ELEFD
ELPLNM

VARIABLE/PARAMETER= UTCARC
ELEFD
ELCOST

VARIABLE/PARAMETER= UTCARN
ELEFD
ELCOST

VARIABLE/PARAMETER= UTCO1C
ELEFD
ELCOST

VARIABLE/PARAMETER= UTCO1N
ELEFD
ELCOST

VARIABLE/PARAMETER= UTCO2C
ELEFD
ELCOST

VARIABLE/PARAMETER= UTCO2N
ELEFD
ELCOST

VARIABLE/PARAMETER= UTEXPE
ELDISP

VARIABLE/PARAMETER= UTIMPE
ELDISP

VARIABLE/PARAMETER= UTJUMP
ELSO2L

VARIABLE/PARAMETER= UTLSO2
ELSO2L

VARIABLE/PARAMETER= UTLSO2I
ELSO2L

VARIABLE/PARAMETER= UTNOXC
ELEFD
ELCOST

VARIABLE/PARAMETER= UTNOXN
ELEFD
ELCOST

VARIABLE/PARAMETER= UTPSO2
ELSO2L

VARIABLE/PARAMETER= UTSO2C
ELEFD
ELCOST

VARIABLE/PARAMETER= UTSO2N
ELEFD
ELCOST

VARIABLE/PARAMETER= UTVOCC
ELEFD
ELCOST

VARIABLE/PARAMETER= U_CAP
ELRNEW

VARIABLE/PARAMETER= WGHT
ELFSHR

VARIABLE/PARAMETER= WRSSHR
ELFSHR

VARIABLE/PARAMETER= X
ELGETY

VARIABLE/PARAMETER= XINT
ELLOAD
ELGTXY

VARIABLE/PARAMETER= XPVPNT
ELALOC

VARIABLE/PARAMETER= XSHR
ELGETY

VARIABLE/PARAMETER= X_VAL
ELRNEW

VARIABLE/PARAMETER= Y0
ELGTXY

VARIABLE/PARAMETER= YINT
ELLOAD
ELGTXY

VARIABLE/PARAMETER= YOUT
ELGETY

VARIABLE/PARAMETER= YPVPNT
ELALOC

VARIABLE/PARAMETER= YVAL
ELALOC

VARIABLE/PARAMETER= Y_VAL
ELRNEW

VARIABLE/PARAMETER= ZCFL
ELMRIT

VARIABLE/PARAMETER= ZFAC
ELMRIT

VARIABLE/PARAMETER= ZHR
ELMRIT

VARIABLE/PARAMETER= ZOMR
ELMRIT

VARIABLE/PARAMETER= ZSCRB
ELMRIT

VARIABLE/PARAMETER= ZSHR
ELMRIT

VARIABLE/PARAMETER= ZSO2
ELMRIT

Table A-23 : Variable, Common Block, Description Cross Reference

Variable Name	Common	Description
ABSTOL	NCNTRL	MINIMUM ABSOLUTE CONVERGENCE TOLERANCE
APTR(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
APTRI(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
AREAIT(EFDMPG,EFDMVS)	DISPETT	
AREANT(EFDMPG,EFDMVS)	DISPETT	
AREATI(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
AREATR(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
AREATT(EFDMPG,EFDMVS)	DISPETT	
BASEYR	NCNTRL	YEAR CORRESPONDING TO FIRSYR=1 (EG. 1990)
CANBLD(MNUMNR)	DISPETT	
CAPTR(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
CAPTRI(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
CASTS(EFD$MPG)	DISPETT	
CI$CF(ECP$CIS,MNUMNR)	DISPETT	CAPACITY FACTOR
CI$CRG(ECP$CIS,MNUMNR)	DISPETT	CANADIAN REGION NUMBER
CI$CST(ECP$CIS,MNUMNR)	DISPETT	COST MILLS/KWH
CI$FMW(ECP$CIS,MNUMNR)	DISPETT	FIRM MW AVAILABLE
CI$PMW(ECP$CIS,MNUMNR)	DISPETT	PEAK MW AVAILABLE
CNVTST(NMODEL,MNUMYR)	NCNTRL	CONVERGENCE TEST FLAGS FOR EACH MODEL
COMMENT	NCNTRL	COMMENT LINE FROM JOB STREAM
CTEST	NCNTRL	OVERALLCONVERGENCETEST(0:NOT,1:CONVERGED)
CURITR	NCNTRL	CURRENT ITERATIONS
CURIYR	NCNTRL	CURRENT YEAR INDEX
DATE	NCNTRL	DATE CODE
DBDUMP	NCNTRL	ON->DB DUMP/YR (0->OFF,1->ON) (DEF=0)
DONE1	DISPETT	
DONE2	DISPETT	
DSMSWTCH	NCNTRL	DSM SWITCH (0 -> OFF, 1 -> ON) (DEF = 1)
EAVLPS(EFDDSP,EFDMSP)	DISPOUT	Cap. Req. by Plant Type&Season
ECACAP(EFD$MPG)	DISPUSE	AVL CAP/SSNAL PER NET OF PMR
ECALLW(EFD$MPG)	DISPIN	ALLOWANCES
ECAPHS(EFDRNW,EFDMSP)	DISPOUT	Cap. by Ren. Technology&Season
ECAPPS(EFDDSP,EFDMSP)	DISPOUT	Cap. Avail. by Plant Type&Ssn
ECASTS(EFD$MPG)	DISPIN	CAPACITY TYPE
ECCAP(EFDMPG,EFDMSP)	DISPIN	CONVENTIONAL CAPACITY
ECCFBD(EFD$DSP,2)	DISPIN	CAPACITY FACTOR BOUNDS
ECCOPM(EFDMPG,EFDMSP)	DISPIN	CAPACITY NET OF PLANNED MAINT.
ECCR(EFD$MPG)	DISPIN	CENSUS REGION
ECDSPC(EFD$MHS)	DISPUSE	CAP IN EACH HORIZONTAL SLICE
ECDSPE(EFD$MHS)	DISPUSE	NRG IN EACH HORIZONTAL SLICE

ECDSPN	DISPUSE	# HOR SLICES REQ TO MEET LOAD
ECDSPP(EFD$MHS,2)	DISPUSE	CUT LINE DEFINING HOR SLICE
ECDSPT(EFD$MHS)	DISPUSE	PLT TYPE/EACH HOR SLICE
ECFLRG(EFDMPG,EFDFPP,EFD$FRG)	DISPIN	SUP./RPT. REG.--FUEL&CAP. GRP
ECFLTP(EFDMPG,EFDFPP)	DISPIN	FUEL TYPE PER CAPACITY GROUP
ECFOR(EFD$MPG)	DISPIN	FORCED OUTAGE RATE
ECFOWN(EFD$MPG)	DISPIN	OWNERSHIP TYPE (PRI,PUB,EWG)
ECFSHR(EFDMPG,EFDFPP)	DISPUSE	FUEL SHARES
ECGR(EFD$MPG)	DISPIN	GAS REGION
ECHTRT(EFDMPG,EFDFPP)	DISPIN	HEATRATE
ECLFR(EFD$MPG)	DISPUSE	LOAD FOLLOWING RATES
ECMFSH(EFDDSP,EFDFPP,EFD$MSP)	DISPIN	MAXIMUM FUEL SHARES
ECMXCP(EFD$MPG)	DISPIN	MAXIMUM CAPACITY FACTOR
ECNR(EFD$MPG)	DISPIN	NERC REGION
ECNTP	DISPIN	NUMBER OF CAPACITY GROUPS
ECOMR(EFDMPG,EFDFPP)	DISPIN	VARIABLE O&M
ECP$CAP	EMM$PARM	ECP TOTAL PLANT TYPES - DSP, INT and RNW
ECP$CIS	EMM$PARM	ECP # OF CANADIAN IMPORT SUPPLY CURVE STEPS
ECP$DBNM	ECP$CNTL	DATABASE NAME
ECP$DECK	ECP$CNTL	DECK NAME
ECP$DECKB(MNUMYR)	ECP$CNTL	BASIS FILE DECK NAME
ECP$DSM	EMM$PARM	ECP NUMBER OF DSM PROGRAM TYPES
ECP$DSP	EMM$PARM	ECP NUMBER OF DISPATCHABLE CAPACITY TYPES
ECP$FILE	ECP$CNTL	INPUT FILE NAME&PATH
ECP$FILEB	ECP$CNTL	EMM BASIS FILE NAME
ECP$FPH	EMM$PARM	LENGTH OF FULL PLANNING HORIZON
ECP$FPP	EMM$PARM	ECP FUELS PER PLANT
ECP$INIT	ECP$CNTL	INITIALIZE MATRIX 1=YES, 0=NO
ECP$INT	EMM$PARM	ECP NUMBER OF INTERMITTENT CAPACITY TYPES
ECP$LCP	EMM$PARM	ECP LONGEST CONSTRUCTION PROFILE
ECP$LDG	EMM$PARM	ECP NUMBER OF BUILDING BLOCKS PER SEASON
ECP$LINV	EMM$PARM	ECP LENGTH OF DSM INVESTMENT PROFILE
ECP$MODE	ECP$CNTL	REVISE MODE 0 - REPLACE EX. MTX.
ECP$MSP	EMM$PARM	ECP SEASONAL PERIOD
ECP$NCC	EMM$PARM	# COEFFICIENTS FOR COAL PRICE EXPECTATIONS EQUATIONS
ECP$NFL	EMM$PARM	ECP NUMBER OF FUEL TYPES
ECP$OWN	EMM$PARM	ECP OWNERSHIP TYPE 1 = UTILITY 2 = NON-UTILITY
ECP$PRNT	ECP$CNTL	PRINT MODE 0 - NO MPS REC. PRINT
ECP$PROB	ECP$CNTL	PROBLEM NAME
ECP$RNW	EMM$PARM	ECP NUMBER OF OTHER RENEWABLE CAPACITY TYPES
ECP$SCR	EMM$PARM	ECP NUMBER OF CLUSTERS--RETROFIT CANDIDATES
ECP$SGP	EMM$PARM	ECP NUMBER OF PLANT GROUPS / RETROFIT GROUP
ECP$SSP	EMM$PARM	ECP MAXIMUM NUMBER OF STEPS PER GROUP
ECP$STP	EMM$PARM	ECP NUMBER OF LOAD GROUPS (IE. SUMMER/DAYTIME)
ECP$VLS	EMM$PARM	ECP NUMBER OF VERTICAL LOAD SEGMENTS
ECP$XPH	EMM$PARM	LENGTH OF EXPLICIT PLANNING HORIZON
ECPACT	ECP$CNTL	YEAR TO WRITE ACTFILE
ECPBASIS	ECP$CNTL	BASIS MODE 0-FRM PREVIOUS YEAR
ECPMR(EFD$MPG)	DISPIN	PLANNED MAINTENANCE RATE
ECPSTART	NCNTRL	START YR FOR ECP MODULE (DEF = 1)
ECSCAP(EFDDSP,EFDVIN,EFD$OWN)	DISPOUT	Summer Capacity (End-Year)
ECSCRB(EFD$MPG)	DISPIN	SCRUBBER EFFICIENCY
ECSRET(EFDDSP,EFDOWN)	DISPOUT	Cum. Retirements (End-Year)
ECTYP(EFD$MPG)	DISPUSE	MERIT ORD MAP (1=MOST ECON)

ECVCST(EFD$MPG)	DISPUSE	VARIABLE O&M COST
EEITAJ(EFD$MSP)	DISPIN	NET IMPORTS/EXPORTS
EEMRM	DISPOUT	Reserve Margin Achieved
EENSP	DISPIN	NUMBER OF SEASONAL PERIODS
EESSHR(EFD$MSP)	DISPIN	SEASONAL DEMAND SHARE
EETIME(EFD$MSP)	DISPIN	NUMBER OF HOURS PER SEASON
EFACTR	DISPIN	CONVERTS I2 TO R4(IE. * .001>
EFD$BTP	EMM$PARM	BOILER TYPES
EFD$CAP	EMM$PARM	TOTAL PLANT TYPES DSP AND RNW
EFD$CGP	EMM$PARM	COMPLIANCE GROUPS PER PLANT GROUP
EFD$DSP	EMM$PARM	DISPATCHABLE CAPACITY TYPES
EFD$FPP	EMM$PARM	ECP FUELS PER PLANT
EFD$FRG	EMM$PARM	SUPPLY/REPORTING REGIONS PER FUEL TYPE
EFD$LDG	EMM$PARM	NUMBER OF BUILDING BLOCKS PER SEASON
EFD$MFRG	EMM$PARM	MAXIMUM NUMBER OF REGIONS FOR ANY FUEL TYPE
EFD$MHG	EMM$PARM	RENEWABLE GROUPS
EFD$MHS	EMM$PARM	HORIZONTAL SLICES
EFD$MPG	EMM$PARM	PLANT GROUPS
EFD$MSP	EMM$PARM	SEASONAL PERIODS
EFD$MVS	EMM$PARM	VERTICAL SLICES
EFD$NFL	EMM$PARM	NUMBER FUEL TYPES
EFD$OWN	EMM$PARM	OWNERSHIP TYPE 1=PRIVATE 2=PUBLIC 3=EWG
EFD$RNW	EMM$PARM	RENEWABLE TYPES
EFD$SO2	EMM$PARM	SO2 COMPLIANCE GROUPS
EFD$VIN	EMM$PARM	VINTAGE 1=EXISTING, 2=PIPELINE, 3=NEW
EFDGRP(ELDHRS,ELDDAY)	DISPIN	INDEX FOR EFD SLICE/GRP SEG.
EFDNSP(ELD$DAY)	DISPIN	NUMBER OF SEGMENTS PER GROUP
EFHCNT(EFD$NFL)	DISPOUT	Avg. Btu Content by Fuel Type
EFP$CAP	EMM$PARM	FINANCIAL PLANT TYPES DSP, INT, AND RNW
EFP$OWN	EMM$PARM	OWNERSHIP TYPE 1=PRIVATE 2=PUBLIC
EFP$SCR	ECP$CNTL	EFP TYPE RETROFIT = 13
EFP$TRN	ECP$CNTL	EFP TYPE TRANSMISSION = 14
EFP$VIN	EMM$PARM	VINTAGE 1 = 1990, 2 = 1989 ... 34 <= 1955
EFRCO2(EFD$NFL)	DISPOUT	Avg. CO2 Content by Fuel Type
EFRNOX(EFD$NFL)	DISPOUT	Avg. NOX Content by Fuel Type
EFRSO2(EFD$NFL)	DISPOUT	Avg. SO2 Content by Fuel Type
EFTOV(ELFT$ET1)	DISPETT	
EFTV(ELFT$ET3)	DISPETT	
EGALLW(EFD$SO2)	DISPOUT	SO2 Allowances by Compl. Grp
EGENHS(EFDRNW,EFDMSP)	DISPOUT	Gen. by Ren. Technology&Season
EGENPS(EFDDSP,EFDMSP)	DISPOUT	Gen. by Plant Type and Season
EGPSO2(EFD$SO2)	DISPOUT	SO2 Penalty Cost by Compl. Grp
EGSO2(EFD$SO2)	DISPOUT	SO2 Emissions by Compl. Grp
EHCAP(EFDMHG,EFDMSP)	DISPIN	RENEWABLE CAPACITY
EHCR(EFD$MHG)	DISPIN	CENSUS REGION
EHFOWN(EFD$MHG)	DISPIN	OWNERSHIP TYPE(PRI,PUB,EWG)
EHHTRT(EFD$MHG)	DISPIN	RENEWABLE HEATRATE
EHHYCF(EFDMHG,EFDMSP)	DISPIN	RENEWABLE CAPACITY FACTOR
EHHYTP(EFD$MHG)	DISPIN	RENEWABLE TYPE
EHNR(EFD$MHG)	DISPIN	NERC REGION
EHNTP	DISPIN	NUMBER OF RENEWABLE GROUPS
EHSCAP(EFDRNW,EFDVIN,EFD$OWN)	DISPOUT	Summer Capacity (End-Year)
EHSRET(EFDRNW,EFDOWN)	DISPOUT	Cum. Retirements (End-Year)
EHVOMR(EFD$MHG)	DISPIN	VARIABLE O&M
EIDCHK	DISPUSE	TEST VAR(LOAD MET=1,ELSE=0)
EIFPLT	DISPIN	NUMBER OF FUELS PER PLANT

EIHGRP	DISPIN	NUMBER OF REN. PLANT TYPE GRPS
EIMCG	DISPIN	NUMBER COMPLIANCE GROUPS
EIPGRP	DISPIN	NUMBER OF DSP. PLANT TYPE GRPS
EISO2(EFDMPG,EFDCGP)	DISPIN	COMPLIANCE GROUP
EITAJ(EFD$MSP,MNUMNR)	DISPETT	
ELASSW	NCNTRL	Elasticity Switch (0->No Elas Calc,1->Calc)
ELD$DAY	EMM$PARM	SEASON / TIME OF DAY GROUPS
ELD$HRS	EMM$PARM	SEGMENTS IN EACH SEASON/TIME OF DAY GROUPS
ELGRP(EFDMVS,EFDMSP)	DISPIN	TIME OF DAY/SEASON GROUP INDEX
ELNGRP	DISPIN	NUMBER OF TIME OF DAY GROUPS
ELNMGRP(ELD$DAY)	DISPIN	TIME OF DAY/SSN GRPS
ELNSPG(ELD$DAY)	DISPIN	TIME OF DAY PER DAY/SEASON GRP
ELNVCT(EFD$MSP)	DISPIN	NUMBER OF POINTS IN LOAD CURVE
ELSEG(EFDMVS,EFDMSP)	DISPIN	TIME OF DAY/SEASON SEG. INDEX
ELXVAL(EFDMVS,EFDMSP)	DISPIN	X VALUE OF SEASONAL LOAD CURVE
ELYVAL(EFDMVS,EFDMSP)	DISPIN	Y VALUE OF SEASONAL LOAD CURVE
ENDYR	NCNTRL	YEAR CORRESPONDING TO LASTYR=29 (EG. 2030)
ENFLTP	DISPOUT	Number of Fuel Types
ENHGRP(EFD$RNW)	DISPIN	RENEWABLE PLANT TYPES
ENMFL(EFD$NFL)	DISPOUT	NAME FOR EACH FUEL TYPE
ENPGRP(EFD$DSP)	DISPIN	NAME OF PLANT TYPES
ENSO2	DISPOUT	Number of Compliance Groups
EPALCO2(ECP$XPH)	BILDIN	CO2 EMISSIONS ALLOWANCES
EPALNOX(ECP$XPH)	BILDIN	NOX EMISSIONS ALLOWANCES
EPALSO2(ECP$XPH)	BILDIN	SO2 EMISSIONS ALLOWANCES
EPCCRF(ECP$CAP)	BILDIN	FIXED CHARGE FACTOR TRANS.
EPCENSUS	BILDIN	CENSUS REGION
EPCFOM(ECP$CAP)	BILDIN	FIXED O&M TRANSMISSION
EPCLRG	BILDIN	COAL REGION
EPCOVR(ECP$CAP)	BILDIN	OVERNIGHT COST TRANSMISSION
EPCRMP(EFD$NFL,MNUMCR)	BILDIN	NERC REG MAP TO CENSUS REG
EPDCCR(ECPDSM,ECPXPH)	BILDIN	CAPACITY CREDIT--DSM
EPDINV(ECPDSM,ECPXPH)	BILDIN	CUMUL. NET PV-NOMINAL DSM INV.
EPDLSI(ECPDSM,ECPVLS,ECP$XPH)	BILDIN	DSM LOAD IMPACT BY SEGMENT&YR
EPDSCRT	BILDIN	UTIL DSC RT (NOM, TAX ADJ ROR)
EPEAK(EFD$MSP)	DISPOUT	Peak Requirement by Season
EPFCH4(EFD$NFL)	BILDIN	CH4 EMISSION RATE BY FUEL
EPFCO1(EFD$NFL)	BILDIN	CO EMISSION RATE BY FUEL
EPFCO2(EFD$NFL)	BILDIN	CO2 EMISSION RATE BY FUEL
EPFCRB(EFD$NFL)	BILDIN	CARBON EMISSION RATE BY FUEL
EPFLRG(EFDNFL,EFDMFR	BILDIN	NERC REG MAP TO EACH FUEL REG
EPFLTP(ECPDSP,ECPFPP)	BILDIN	ECP FUEL TYPES--DSP. CAP.
EPFMAP(EFDNFL,ECPNFL)	BILDIN	EFD TO ECP FUEL TYPES
EPFNOX(EFD$NFL)	BILDIN	NOX EMISSION RATE BY FUEL
EPFSOX(EFD$NFL)	BILDIN	SOX EMISSION RATE BY FUEL
EPFUEL(EFD$NFL)	DISPOUT	Avg. Fuel Price by Fuel Type
EPFVOC(EFD$NFL)	BILDIN	VOC EMISSION RATE BY FUEL
EPHGHT(ECPVLS,ECPXPH)	BILDIN	HEIGHT OF VERTICAL LOAD SEGS
EPIACF(ECP$INT)	BILDIN	AVERAGE CAP FACTR/--INT. CAP.
EPIAVL(ECP$INT)	BILDIN	COMMERCIAL OP. DATE--INT. CAP
EPICAP(ECPINT,ECPXPH)	BILDIN	EXISTING INT. CAPACITY
EPICCR(ECP$INT)	BILDIN	CAPACITY CREDIT--INT. CAP
EPICFC(ECPINT,ECPVLS)	BILDIN	CAPACITY FACTR/LOAD--INT. CAP.
EPICH4(ECP$INT)	BILDIN	CH4 EMISSION RATE--INT. CAP
EPICLT(ECP$INT)	BILDIN	CONSTRUCTION LDTIME--INT. CAP
EPICO1(ECP$INT)	BILDIN	CO EMISSION RATE --INT. CAP

EPICO2(ECP$INT)	BILDIN	CO2 EMISSION RATE--INT. CAP
EPICPR(ECPLCP,ECPINT)	BILDIN	CONSTRUCTION PROFILE--INT. CAP
EPICRB(ECP$INT)	BILDIN	CARBON EMISSION RATE--INT. CAP
EPICSB(ECP$INT)	BILDIN	CAPITAL COST CREDIT-INT. CAP
EPIELF(ECP$INT)	BILDIN	ECONOMIC LIFE--INT. CAP
EPIFOM(ECP$INT)	BILDIN	FIXED O&M COST--INT. CAP
EPIFOR(ECP$INT)	BILDIN	FORCED OUTAGE RATE--INT. CAP.
EPIFTY(ECP$INT)	BILDIN	INPUT FUEL TYPE--INT. CAP
EPIHRT(ECP$INT)	BILDIN	HEAT RATE--INT. CAP.
EPINCLF(ECP$INT)	BILDIN	NUG CONTRACT LIFE--INT. CAP
EPINLLF(ECP$INT)	BILDIN	NUG LOAN LIFE --INT. CAP
EPINOX(ECP$INT)	BILDIN	NOX EMISSION RATE--INT. CAP
EPIOVR(ECP$INT)	BILDIN	OVERNIGHT CAP COST-INT. CAP
EPIPMR(ECP$INT)	BILDIN	PLANNED MAINT. RATE--INT. CAP.
EPISOX(ECP$INT)	BILDIN	SO2 EMISSION RATE--INT. CAP
EPITLF(ECP$INT)	BILDIN	TAX LIFE--INT. CAP
EPIUCLF(ECP$INT)	BILDIN	UTIL CONTRACT LIFE--INT. CAP
EPIVOC(ECP$INT)	BILDIN	VOC EMISSION RATE--INT. CAP
EPIVOM(ECP$INT)	BILDIN	VARIABLE O&M COST--INT. CAP
EPIVSB(ECP$INT)	BILDIN	O&M COST CREDIT--INT. CAP
EPLDGR(ECPVLS,ECPXPH)	BILDIN	LOAD GROUP (E.G. SUMMER DAY)
EPLDSG(ECPVLS,ECPXPH)	BILDIN	LOAD SEGMENT(E.G. PEAK,OFFPK)
EPLMAP(ECPSTP,ECPSSZ,ECP$XPH)	BILDIN	LOAD GROUP TO ECP STEP MAP
EPLOVR(ELFT$BLD)	BILDIN	LFTOVR BYTES
EPMRM	BILDIN	MIN RESERVE MARGIN-PLANNING
EPNFDT	BILDIN	NUG DEBT FRACTION
EPNGRG	BILDIN	NATURAL GAS REGION
EPNIPRM	BILDIN	NUG INTEREST PREMIUM
EPNPCLF(ECP$XPH)	BILDIN	PURCHASED CAP LIMIT FACT-NUG
EPNRPRM	BILDIN	NUG RETURN ON EQUITY PREMIUM
EPNSCR(ECPDSP,ECPSCR)	BILDIN	# PLANTS IN A RETROFIT GROUP
EPNSPG(ELD$DAY)	BILDIN	NUMBER OF STEPS PER GROUP
EPNSTP(ECP$XPH)	BILDIN	NUMBER OF VERTICAL STEPS
EPPAVL(ECP$DSP)	BILDIN	COMMERCIAL OP. DATE--DSP. CAP
EPPCAP(ECPDSP,ECPXPH)	BILDIN	EXISTING DSP. CAPACITY
EPPCCR(ECP$DSP)	BILDIN	CAPACITY CREDIT--DSP. CAP
EPPCFB(ECP$DSP,2)	BILDIN	MIN/MAX CAP. FACTOR--DSP. CAP.
EPPCLRHS(ECP$XPH)	BILDIN	PURCHASED CAP LIMIT RHS VALUE
EPPCLT(ECP$DSP)	BILDIN	CONSTRUCTION LDTIME--DSP. CAP
EPPCPR(ECPLCP,ECPDSP)	BILDIN	CONSTRUCTION PROFILE--DSP. CAP
EPPCSB(ECP$DSP)	BILDIN	CAPITAL COST CREDIT-DSP. CAP
EPPEAK(ECP$XPH)	BILDIN	PEAK LOAD
EPPELF(ECP$DSP)	BILDIN	ECONOMIC LIFE--DSP. CAP
EPPFL(ECPNFL,ECPXPH)	BILDIN	PV OF NOMINAL ECP FUEL PRICES
EPPFOM(ECP$DSP)	BILDIN	FIXED O&M COST--DISP. CAP
EPPFOR(ECP$DSP)	BILDIN	FORCED OUTAGE RATE--DSP. CAP.
EPPHRT(ECP$DSP)	BILDIN	HEAT RATE--DSP. CAP.
EPPMAP(ECPCAP,EFDCAP)	BILDIN	ECP TO EFD PLANT TYPE MAP
EPPMCF(ECP$DSP)	BILDIN	MAX CAP. FACTOR--DSP. CAP.
EPPNCLF(ECP$DSP)	BILDIN	NUG CONTRACT LIFE--DSP. CAP
EPPNLLF(ECP$DSP)	BILDIN	NUG LOAN LIFE --DSP. CAP
EPPOVR(ECP$DSP)	BILDIN	OVERNIGHT CAP COST-DSP. CAP
EPPPMR(ECP$DSP)	BILDIN	PLANNED OUTAGE RATE--DSP. CAP.
EPPSEF(ECP$DSP)	BILDIN	SCRUBBER EFFICIENCY--DSP. CAP.
EPPSRT(ECP$DSP)	BILDIN	SCRUBBER SO2 EMISSIONS RATE
EPPTLF(ECP$DSP)	BILDIN	TAX LIFE--DSP. CAP

EPPUCLF(ECP$DSP)	BILDIN	UTIL CONTRACT LIFE--DSP. CAP
EPPVOM(ECP$DSP)	BILDIN	VARIABLE O&M COST--DSP. CAP
EPPVSB(ECP$DSP)	BILDIN	O&M COST CREDIT--DSP. CAP
EPRAVL(ECP$RNW)	BILDIN	COMMERCIAL OP. DATE--REN. CAP
EPRCAP(ECPRNW,ECPXPH)	BILDIN	EXISTING REN. CAPACITY
EPRCCR(ECP$RNW)	BILDIN	CAPACITY CREDIT--RNW. CAP
EPRCFC(ECP$RNW)	BILDIN	MAX CAPACITY FACTOR--RNW. CAP.
EPRCH4(ECP$RNW)	BILDIN	CH4 EMISSION RATE--RNW. CAP
EPRCLT(ECP$RNW)	BILDIN	CONSTRUCTION LDTIME--REN. CAP
EPRCO1(ECP$RNW)	BILDIN	CO EMISSION RATE --RNW. CAP
EPRCO2(ECP$RNW)	BILDIN	CO2 EMISSION RATE--RNW. CAP
EPRCPR(ECPLCP,ECPRNW)	BILDIN	CONSTRUCTION PROFILE--RNW. CAP
EPRCRB(ECP$RNW)	BILDIN	CARBON EMISSION RATE--RNW. CAP
EPRCSB(ECP$RNW)	BILDIN	CAPITAL COST CREDIT-RNW. CAP
EPRELF(ECP$RNW)	BILDIN	ECONOMIC LIFE--REN. CAP
EPRFOM(ECP$RNW)	BILDIN	FIXED O&M COST--RNW. CAP
EPRFOR(ECP$RNW)	BILDIN	FORCED OUTAGE RATE--RNW. CAP.
EPRFTY(ECP$RNW)	BILDIN	INPUT FUEL TYPE--RNW. CAP
EPRHRT(ECP$RNW)	BILDIN	HEAT RATE--RNW. CAP.
EPRNCLF(ECP$RNW)	BILDIN	NUG CONTRACT LIFE--RNW. CAP
EPRNLLF(ECP$RNW)	BILDIN	NUG LOAN LIFE --RNW. CAP
EPRNOX(ECP$RNW)	BILDIN	NOX EMISSION RATE--RNW. CAP
EPROVR(ECP$RNW)	BILDIN	OVERNIGHT CAP COST-RNW. CAP
EPRPMR(ECP$RNW)	BILDIN	PLANNED MAINT. RATE--RNW. CAP.
EPRSOX(ECP$RNW)	BILDIN	SO2 EMISSION RATE--RNW. CAP
EPRTBS	BILDIN	INITIAL RATE BASE
EPRTLF(ECP$RNW)	BILDIN	TAX LIFE--RNW. CAP
EPRUCLF(ECP$RNW)	BILDIN	UTIL CONTRACT LIFE--RNW. CAP
EPRVOC(ECP$RNW)	BILDIN	VOC EMISSION RATE--RNW. CAP
EPRVOM(ECP$RNW)	BILDIN	VARIABLE O&M COST--RNW. CAP
EPRVSB(ECP$RNW)	BILDIN	O&M COST CREDIT--RNW. CAP
EPSCAP(ECPDSP,ECPSCR)	BILDIN	UPPER LIMIT-RETROFIT
EPSCLT	BILDIN	CONSTRUCTION LEADTIME--RETRO.
EPSCPEN(ECPDSP,ECPSCR)	BILDIN	CAPACITY PEN. (%)-RETROFIT
EPSCPR(ECP$LCP)	BILDIN	CONS. PROFILE--RETROFIT
EPSCR2(ECP$DSP)	BILDIN	ECP CAPACITY TYPE CONVERTED TO
EPSELF	BILDIN	ECONOMIC LIFE--SCRUBBER RETRO.
EPSHPEN(ECPDSP,ECPSCR)	BILDIN	HEAT RATE PEN. (%)-RETROFIT
EPSNDX(ECP$STP)	BILDIN	LOAD GROUP TO EFD SEASON MAP
EPSOVR(ECPDSP,ECPSCR)	BILDIN	OVERNIGHT CAP COST-RETROFIT
EPSO2(EFD$SO2)	DISPIN	SO2 PENALTY COST
EPSPK(ECPMSP,ECPXPH)	BILDIN	SEASONAL PEAK LOAD
EPSREC(ECPSGP,ECPDSP,ECP$SCR)	BILDIN	REC #/EACH PLNT IN A RET GRP
EPTCRF(MNUMNR)	BILDIN	TRANSM. ANN. FACTOR-IRT BLDS
EPTCST(MNUMNR)	BILDIN	TRANSM. COST FOR IRT BLDS
EPTIRGN(MNUMNR)	BILDIN	TRANSM. IMPORT REG-IRT BLDS
EPTLOSS(MNUMNR)	BILDIN	TRANSM. LOSS FOR IRT BLDS
EPTXRT	BILDIN	NET TAX RATE
EPUCRE	BILDIN	UTIL COMMON RETURN ON EQUITY
EPUFDT	BILDIN	UTIL DEBT FRACTION
EPUFPE	BILDIN	UTIL ((CE*FRAC+PE*FRAC)/ROR)
EPUIRT	BILDIN	UTIL INTEREST RATE
EPUPCLF(ECP$XPH)	BILDIN	PURCHASED CAP LIMIT FACT-UTIL
EPUROR	BILDIN	UTIL ROR (WGT AVG CE,PE,DEBT)
EPWDTH(ECPVLS,ECPXPH)	BILDIN	WIDTH OF VERTICAL LOAD SEGS
EPXPRT(ECP$XPH)	BILDIN	ELECTRICITY EXPORT LIMITS

EQEL	DISPIN	TOTAL ELECTRICITY DEMAND
EQFCO2(EFD$NFL)	DISPOUT	CO2 Emissions by Fuel Type
EQFFL(EFDNFL,EFDOWN)	DISPOUT	Fuel Consumption by Fuel Type
EQFGN(EFDNFL,EFDOWN)	DISPOUT	Generation by Fuel Type
EQFNOX(EFD$NFL)	DISPOUT	NOX Emissions by Fuel Type
EQFSO2(EFD$NFL)	DISPOUT	SO2 Emissions by Fuel Type
EQHCP(EFD$RNW)	DISPOUT	Avg. Annual Cap. by Ren. Tech
EQHGN(EFDRNW,EFDOWN)	DISPOUT	Generation by Ren. Technology
EQLOAD(2)	DISPUSE	TOT LOAD&CUM AREA UND CUT LNE
EQPCO2(EFD$DSP)	DISPOUT	CO2 Emissions by Plant Type
EQPCP(EFD$DSP)	DISPOUT	Avg. Annual Cap. by Plant Type
EQPFL(EFD$DSP)	DISPOUT	Fuel Consumption by Plant Type
EQPGN(EFDDSP,EFDOWN)	DISPOUT	Generation by Plant Type
EQPNOX(EFD$DSP)	DISPOUT	NOX Emissions by Plant Type
EQPSO2(EFD$DSP)	DISPOUT	SO2 Emissions by Plant Type
EQTDLS	DISPIN	T&D LOSS FACTOR
ERFFL(EFD$NFL)	DISPOUT	Fuel Cost by Fuel Type
ERHOM(EFDRNW,EFDOWN)	DISPOUT	Var. O&M by Ren. Tech, OWN
ERPFL(EFD$DSP)	DISPOUT	Fuel Cost by Plant Type
ERPOM(EFD$DSP)	DISPOUT	Variable O&M by Plant Type
ERTFL(EFD$OWN)	DISPOUT	Total Fuel Cost by Co. Type
ERTOM(EFD$OWN)	DISPOUT	Variable O&M by Company Type
ERTOMF	DISPIN	TOTAL FIXED O&M
ESLCUT(2)	DISPUSE	Y-INT&SLOPE CURRENT CUT LINE
ETALLW	DISPOUT	Total SO2 Allowances
ETAREA(EFD$MVS)	DISPUSE	AREA IN EACH VERTICAL SLICE
ETCAR	DISPOUT	Total Car Emissions
ETCO1	DISPOUT	Total CO1 Emissions
ETCO2	DISPOUT	Total CO2 Emissions
ETDMDE	DISPOUT	Domestic Economy Sales (MM$)
ETDMDF	DISPOUT	Domestic Firm Pwr Sales (MM$)
ETDMME	DISPOUT	Domestic Economy Sales (MWH)
ETDMMF	DISPOUT	Domestic Firm Pwr Sales (MWH)
ETDMPE	DISPOUT	Dom. - Econ. Trade Profit(MM$)
ETDSPN(EFD$MSP)	DISPETT	
ETDSPT(EFDMSP,EFDMPG)	DISPETT	
ETEXPD	DISPOUT	Exports - Revenues (MM$)
ETEXPE	DISPOUT	Exports - Economy(MWH)
ETEXPF	DISPOUT	Exports - Firm (MWH)
ETFSHR(EFDMSP,EFDMPG,EFD$FPP)	DISPETT	
ETGEN	DISPOUT	Total Generation
ETIMPD	DISPOUT	Import Revenues (MM$)
ETIMPE	DISPOUT	Imports - Economy (MWH)
ETIMPF	DISPOUT	Imports - Firm (MWH)
ETNOX	DISPOUT	Total NOX Emissions
ETNVCT	DISPUSE	# POINTS DEFINING LOAD CURVE
ETSO2	DISPOUT	Total SO2 Emissions
ETT$MTG	EMM$PARM	MAXIMUM NUMBER OF TRADE GROUPS
ETT$RECS	EMM$PARM	MAXIMUM # OF RECORDS IN CONSTRAINT FILE
ETVOC	DISPOUT	Total VOC Emissions
ETXVAL(EFD$MVS)	DISPUSE	X VALUES OF Ssnal LOAD CURVE
ETYVAL(EFD$MVS)	DISPUSE	Y VALUES OF Ssnal LOAD CURVE
EWGFIX	DISPOUT	EWG FIXED $ COMPONT
EWGOWN	DISPOUT	Generation by NUGS for Own Use
EWGRCC	DISPOUT	Commercial Cogen - Rev. fr Utl
EWGREV	DISPOUT	EWG - Rev. fr Utl

EWGRIC	DISPOUT	Industrial Cogen - Rev. fr Utl
EWGRNW	DISPOUT	NUGS/Renewables - Rev. fr Utl
EXAREA(EFD$MVS)	DISPETT	
EXC	NCNTRL	RUNMOD(8) EXECUTE COAL (COAL SUPPLY)
EXE	NCNTRL	RUNMOD(7) EXECUTE UTIL (UTILITY)
EXG	NCNTRL	RUNMOD(10) EXECUTE PIPE (GAS TRANS.& DISTR.)
EXI	NCNTRL	RUNMOD(5) EXECUTE IND (INDUSTRIAL)
EXK	NCNTRL	RUNMOD(4) EXECUTE COMM (COMMERCIAL)
EXL	NCNTRL	RUNMOD(9) EXECUTE WELL (OIL AND GAS SUPPLY)
EXM	NCNTRL	RUNMOD(2) EXECUTE MAC (MACROECONOMIC)
EXMAP(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
EXN	NCNTRL	RUNMOD(12) EXECUTE RENEW (RENEWABLES)
EXO	NCNTRL	RUNMOD(11) EXECUTE REFINE (PETROLEUM REFINERY)
EXR	NCNTRL	RUNMOD(3) EXECUTE RESD (RESIDENTIAL)
EXT	NCNTRL	RUNMOD(6) EXECUTE TRAN (TRANSPORTATION)
EXW	NCNTRL	RUNMOD(1) EXECUTE WORLD (INTERNATIONAL)
FBTELNR(NDREG)	UEFDOUT	BIT COAL CONVERGENCE FLAG
FCRL	NCNTRL	FINAL CONVERGENCE AND REPORTING LOOP SWITCH (1=ON)
FIRSYR	NCNTRL	FIRST FORECAST YEAR INDEX (EG. 2)
FLAGSO2	UEFDOUT	PENALTY COST FLAG
FLTELNR(NDREG-1)	UEFDOUT	LIG COAL CONVERGENCE FLAG
FLTYPE=6)	PARAMETR	Fuel type (Oil, NG, MCL, SCL, Ren, Al)
FORE_SITE_CNTL(2)	NCNTRL	DESCRIPTION FOR I4SCNT
FORE_SITE_TYPE(3)	NCNTRL	DESCRIPTION FOR I4SITE
FRCTOL	NCNTRL	MINIMUM FRACTIONAL CONVERGENCE TOLERANCE
FSTELNR(NDREG)	UEFDOUT	SUB COAL CONVERGENCE FLAG
HISTORY	NCNTRL	1990 HISTORY DATA FLAG
IDONE1	DISPETT	
IDONE2	DISPETT	
IMAREA(EFD$MVS)	DISPETT	
IMMAP(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
IRELAX	NCNTRL	OPTION TO RUN HEURISTIC ROUTINE TO SPEED
IRGNUM(MNUMNR)	DISPETT	
ITIMNG	NCNTRL	TIMING SWITCH (ITIMNG=1 MEANS TIMING ON)
IYVAL(EFD$MVS)	DISPETT	
I4SCNT	NCNTRL	FORESIGHT CONTROL: (1: MAIN, 2: SUBMODULE)
I4SITE	NCNTRL	FORESITE OPTION (1:MYOPIC,2:ADAPTIVE,3: PERFECT)
LASTYR	NCNTRL	LAST FORECAST YEAR INDEX (EG. 26)
LEFTOV(ELFT$ET1)	DISPETT	
LEFTV(ELFT$ET3)	DISPETT	
LFTOUT(ELFT$OUT)	DISPOUT	LEFTOVER BYTES
LFTOVR(ELFT$IN)	DISPIN	LEFTOVER BYTES
LFTSO2(ELFT$SO2)	USO2GRP	LEFTOVER BYTES
LOOP(2)	NCNTRL	DESCRIPTION FOR LOOPOP
LOOPOP	NCNTRL	NEMS YR LOOPING (1:ONE YR AT A TIME,2:ALL YR)
MACFDBK	NCNTRL	MACROECONOMIC FEEDBACK LEVER (1=ON)
MAREA(EFD$MVS)	DISPETT	
MAXITR	NCNTRL	MAXIMUM ITERATIONS
MMAC	NCNTRL	MACRO CASE
MMAP(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
MNCLTYPE=16)	PARAMETR	Coal type
MNCROP=2)	PARAMETR	Emissions (Corn & Biomass)
MNDSMPCM=10)	PARAMETR	Number of DSM programs - commercial
MNDSMPRS=10)	PARAMETR	Number of DSM programs - residential

MNETOH=5)	PARAMETR	Emissions of Ethanol, 5 Volume steps
MNGRADCR=5)	PARAMETR	Grades of crude oil {3(API gravity)+2(sulfur)}
MNMFTYPE=29)	PARAMETR	No of Mfg Types (1=Nat, 2-8=Non-Mfg, 9-29=Mfg)
MNOGCAT=12)	PARAMETR	Oil & Gas categories (EOR+Convential+
MNOGCRO=5)	PARAMETR	(EOR+Conventional+Offshore+Ak+US)
MNPOLLUT=8)	PARAMETR	Air Pollutants (C,CO,CO2,SOx,NOx,VOC,CH4,PART)
MNSICM=40)	PARAMETR	Mfg: number of SIC's
MNSICNM=12)	PARAMETR	Non-mfg: number of SIC's
MNUMBX=18)	PARAMETR	No. NG border crossings (Canada-6,
MNUMCR=11)	PARAMETR	Census regions (9+CA+US)
MNUMGR=15)	PARAMETR	NGTDM regions {9(census)+3(west)+AL+HW+US}
MNUMLR=17)	PARAMETR	Coal supply regions (16+US)
MNUMNR=16)	PARAMETR	NERC regions (13+Alaska+Ha+US)
MNUMOR=13)	PARAMETR	Oil & Gas (OGSM) regions
MNUMPR=6)	PARAMETR	PADD regions (5 + US)
MNUMXR=11)	PARAMETR	Coal export regions (10+US)
MNUMYR=29)	PARAMETR	Years=1990-2015,2020,2025,2030
MNXYR=66)	PARAMETR	No of Expectation years (1990-2015, 2016-2066)
MODELON	NCNTRL	ON->MODS NEVER OFF (0->OFF, 1->ON) (DEF= 0)
MORDER(NMODEL)	NCNTRL	HOLDS EXECUTION ORDER OF MODULES
MSEDYR=2)	PARAMETR	Number of Historical SEDS years
NCRL	NCNTRL	REPORTING LOOP SWITCH FOR EACH MODEL (1=ON)
NDREG=23)	PARAMETR	Coal demand regions
NTCOS(EFDMSP,EFDMPG)	DISPETT	
NYRS	NCNTRL	NUMBER OF GROWTH YEARS
PRTDBGC	NCNTRL	PRINT DEBUG IN COAL (COAL SUPPLY)
PRTDBGE	NCNTRL	PRINT DEBUG IN UTIL (UTILITY)
PRTDBGN	NCNTRL	PRINT DEBUG IN PIPE (GAS TRANS.& DISTR.)
PRTDBGI	NCNTRL	PRINT DEBUG IN IND (INDUSTRIAL)
PRTDBGK	NCNTRL	PRINT DEBUG IN COMM (COMMERCIAL)
PRTDBGL	NCNTRL	PRINT DEBUG IN WELL (OIL AND GAS SUPPLY)
PRTDBGM	NCNTRL	PRINT DEBUG IN MAC (MACROECONOMIC)
PRTDBGN	NCNTRL	PRINT DEBUG IN RENEW (RENEWABLES)
PRTDBGO	NCNTRL	PRINT DEBUG IN REFINE (PETROLEUM REFINERY)
PRTDBGR	NCNTRL	PRINT DEBUG IN RESD (RESIDENTIAL)
PRTDBGT	NCNTRL	PRINT DEBUG IN TRAN (TRANSPORTATION)
PRTDBGW	NCNTRL	PRINT DEBUG IN WORLD (INTERNATIONAL)
QBCELNR(NDREG,MNUMYR)	UEFDOUT	VLS BIT COAL CONSUMPTION BY COAL Reg
QBDELNR(NDREG,MNUMYR)	UEFDOUT	LS BIT COAL CONSUMPTION BY COAL Reg
QBHELNR(NDREG,MNUMYR)	UEFDOUT	HS BIT COAL CONSUMPTION BY COAL Reg
QBMELNR(NDREG,MNUMYR)	UEFDOUT	MS BIT COAL CONSUMPTION BY COAL Reg
QBTELNR(NDREG,MNUMYR)	UEFDOUT	BIT COAL CONSUMPTION BY COAL REG
QGCELGR(21,MNUMYR)	UEFDOUT	NG "COMPET" CONSUMPTION BY NGTDM
QGFELGR(21,MNUMYR)	UEFDOUT	NG "FIRM" CONSUMPTION BY NGTDM
QGIELGR(21,MNUMYR)	UEFDOUT	NG "INTER" CONSUMPTION BY NGTDM
QLCELNR(NDREG,MNUMYR)	UEFDOUT	VLS LIG COAL CONSUMPTION BY COAL REG
QLDELNR(NDREG,MNUMYR)	UEFDOUT	LS LIG COAL CONSUMPTION BY COAL REG
QLHELNR(NDREG,MNUMYR)	UEFDOUT	HS LIG COAL CONSUMPTION BY COAL REG
QLMELNR(NDREG,MNUMYR)	UEFDOUT	MS LIG COAL CONSUMPTION BY COAL REG
QLTELNR(NDREG,MNUMYR)	UEFDOUT	LIG COAL CONSUMPTION BY COAL REG
QSCELNR(NDREG,MNUMYR)	UEFDOUT	VLS SUB COAL CONSUMPTION BY COAL Reg
QSDELNR(NDREG,MNUMYR)	UEFDOUT	LS SUB COAL CONSUMPTION BY COAL Reg
QSHELNR(NDREG,MNUMYR)	UEFDOUT	HS SUB COAL CONSUMPTION BY COAL REG
QSMELNR(NDREG,MNUMYR)	UEFDOUT	MS SUB COAL CONSUMPTION BY COAL REG
QSTELNR(NDREG,MNUMYR)	UEFDOUT	SUB COAL CONSUMPTION BY COAL REG
QTDLS(MNUMNR)	DISPETT	

REAIT(EFDMPG,EFDMVS)	DISPETT	
REANT(EFDMPG,EFDMVS)	DISPETT	
REATI(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
REATR(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
REATT(EFDMPG,EFDMVS)	DISPETT	
RGNUM(MNUMNR)	DISPETT	
RLXPC	NCNTRL	RELAXATION PERCENTAGE
RNCSI(MNUMNR)	DISPETT	
RNCST(MNUMNR)	DISPETT	
RNCWI(MNUMNR)	DISPETT	
RNCWT(MNUMNR)	DISPETT	
RUNMOD(NMODEL)	NCNTRL	FLAGS FOR WHETHER EACH MODEL IS BEING RUN
SCALPR	NCNTRL	FOR REPORTING, DEFLATOR, YEARPR $ (EG 1.315)
SCEN	NCNTRL	SCENARIO
SUBR_DESCR(NMODEL)	NCNTRL	LONG SUBROUTINE NAMES
SUBR_NAMES(NMODEL)	NCNTRL	SHORT SUBROUTINE NAMES
SUBR_VERS(NMODEL+2)	NCNTRL	SUBROUTINE VERSION USED:
TDMDF(MNUMNR)	DISPETT	
TDMMF(MNUMNR)	DISPETT	
TDSPN(EFD$MSP)	DISPETT	
TDSPT(EFDMSP,EFDMPG)	DISPETT	
TEXDF(MNUMNR)	DISPETT	
TEXMF(MNUMNR)	DISPETT	
TEXPD(MNUMNR)	DISPETT	
TEXPF(MNUMNR)	DISPETT	
TFSHR(EFDMSP,EFDMPG,EFD$FPP)	DISPETT	
TIMPD(MNUMNR)	DISPETT	
TIMPF(MNUMNR)	DISPETT	
TIYVAL(EFD$MVS)	DISPETT	
TQDFRHG(21)	DISPUSE	DUAL-FIRED RH USE--GAS REGS
TQDFRLG(21)	DISPUSE	DUAL-FIRED RL USE--GAS REGS
TRGCMAX(21)	DISPUSE	TEMP TOTAL FOR MAX G/O RAT
TRGCMIN(21)	DISPUSE	TEMP TOTAL FOR MIN G/O RAT
TRGCPAR(21)	DISPUSE	TEMP TOTAL FOR PAR G/O RAT
TRNCSI	DISPIN	SUMMER IMP. TRANSM. CONSTRAINT
TRNCST	DISPIN	SUMMER EXP. TRANSM. CONSTRAINT
TRNCWI	DISPIN	WINTER IMP. TRANSM. CONSTRAINT
TRNCWT	DISPIN	WINTER EXP. TRANSM. CONSTRAINT
TSGCMAX(21)	DISPUSE	TEMP TOTAL FOR MAX GAS SHR
TSGCMIN(21)	DISPUSE	TEMP TOTAL FOR MIN GAS SHR
TSGCPAR(21)	DISPUSE	TEMP TOTAL FOR PAR GAS SHR
TTYVAL(EFD$MVS)	DISPETT	
TYVAL(EFD$MVS)	DISPETT	
UCANBLD(MNUMNR)	DISPETT	
UCASTS(EFD$MPG)	DISPETT	
UCI$CF(ECP$CIS,MNUMNR)	DISPETT	CAPACITY FACTOR
UCI$CRG(ECP$CIS,MNUMNR)	DISPETT	CANADIAN REGION NUMBER
UCI$CST(ECP$CIS,MNUMNR)	DISPETT	COST MILLS/KWH
UCI$FMW(ECP$CIS,MNUMNR)	DISPETT	FIRM MW AVAILABLE
UCI$PMW(ECP$CIS,MNUMNR)	DISPETT	PEAK MW AVAILABLE
UCMFSH(EFDDSP,EFDFPP,MNUMNR)	FUELIN	MAXIMUM FUEL SHARES
UEITAJ(EFD$MSP,MNUMNR)	DISPETT	
UFHCNT(EFDNFL,EFDMFRG)	FUELIN	HEAT CONTENT
UFL$ECP(EFD$NFL,ECP$FPP)	ECP$CNTL	EFD TO ECP FUEL MAPPING
UFLCLNR(2,MNUMNR,MNUMYR)	UEFDOUT	COAL CONS BY OWNERSHIP TYPE/NERC
UFLDSNR(2,MNUMNR,MNUMYR)	UEFDOUT	DS CONS BY OWNERSHIP TYPE/NERC

UFLGCNR(2,MNUMNR,MNUMYR)	UEFDOUT	GAS (COMP.) CONS BY OWNERSHIP TYPE pe/NERC
UFLGFNR(2,MNUMNR,MNUMYR)	UEFDOUT	GAS (FIRM) CONS BY OWNERSHIP TYP e/NERC
UFLGINR(2,MNUMNR,MNUMYR)	UEFDOUT	GAS (INT.) CONS BY OWNERSHIP TYP e/NERC
UFLHYNR(2,MNUMNR,MNUMYR)	UEFDOUT	HYD(NOT PS) CONS BY OWNERSHIP TYpe/NERC
UFLOTNR(2,MNUMNR,MNUMYR)	UEFDOUT	OTH. CONS BY OWNERSHIP TYPE/NERC
UFLPSNR(2,MNUMNR,MNUMYR)	UEFDOUT	PS CONS BY OWNERSHIP TYPE/NERC
UFLRHNR(2,MNUMNR,MNUMYR)	UEFDOUT	RH CONS BY OWNERSHIP TYPE/NERC
UFLRLNR(2,MNUMNR,MNUMYR)	UEFDOUT	RL CONS BY OWNERSHIP TYPE/NERC
UFLTLNR(2,MNUMNR,MNUMYR)	UEFDOUT	TOT CONS BY OWNERSHIP TYPE/NERC
UFLURNR(2,MNUMNR,MNUMYR)	UEFDOUT	NUC CONS BY OWNERSHIP TYPE/NERC
UFRASH(EFD$NFL)	FUELIN	ASH RETENTION RATE
UFRCAR(EFD$NFL)	FUELIN	CARBON EMISSION RATE
UFRCO1(EFD$NFL)	FUELIN	EMISSION RATE
UFRCO2(EFD$NFL)	FUELIN	SO2 EMISSION RATE
UFRNOX(EFDNFL,EFDMFRG)	FUELIN	NOX EMISSION RATE
UFRSO2(EFDNFL,EFDMFRG)	FUELIN	SO2 EMISSION RATE
UFRVOC(EFD$NFL)	FUELIN	VOC EMISSION RATE
UGNCLNR(2,MNUMNR,MNUMYR)	UEFDOUT	COAL GEN BY OWNERSHIP TYPE /NERC
UGNDSNR(2,MNUMNR,MNUMYR)	UEFDOUT	DS GEN BY OWNERSHIP TYPE /NERC
UGNGCNR(2,MNUMNR,MNUMYR)	UEFDOUT	GAS (COMP.) GEN BY OWNERSHIP Type/NERC
UGNGENR(2,MNUMNR,MNUMYR)	UEFDOUT	GEOTHERMAL GEN BY OWNERSHIP type/NERC
UGNGFNR(2,MNUMNR,MNUMYR)	UEFDOUT	GAS (FIRM) GEN BY OWNERSHIP Type/NERC
UGNGINR(2,MNUMNR,MNUMYR)	UEFDOUT	GAS (INT.) GEN BY OWNERSHIP Type/NERC
UGNHONR(2,MNUMNR,MNUMYR)	UEFDOUT	HYD/OTH GEN BY OWNERSHIP type/NERC
UGNHYNR(2,MNUMNR,MNUMYR)	UEFDOUT	HYD (NOT PS) GEN type/NERC
UGNMSNR(2,MNUMNR,MNUMYR)	UEFDOUT	MSW GEN BY OWNERSHIP TYPE/ NERC
UGNPSNR(2,MNUMNR,MNUMYR)	UEFDOUT	PS GEN BY OWNERSHIP TYPE /NERC
UGNPVNR(2,MNUMNR,MNUMYR)	UEFDOUT	PHOTOVOLTAIC GEN BY OWNERSHIP type/NERC
UGNRHNR(2,MNUMNR,MNUMYR)	UEFDOUT	RH GEN BY OWNERSHIP TYPE /NERC
UGNRLNR(2,MNUMNR,MNUMYR)	UEFDOUT	RL GEN BY OWNERSHIP TYPE /NERC
UGNSONR(2,MNUMNR,MNUMYR)	UEFDOUT	SOLAR GEN BY OWNERSHIP TYPE/NERC
UGNTLNR(2,MNUMNR,MNUMYR)	UEFDOUT	TOT. GEN BY OWNERSHIP TYPE /NERC
UGNUBCR(MNUMCR,MNUMYR)	UEFDOUT	UTIL BWR NUCLEAR GENER. BY CENSUS S
UGNUPCR(MNUMCR,MNUMYR)	UEFDOUT	UTIL PWR NUCLEAR GENER. BY CENSUS S
UGNURNR(2,MNUMNR,MNUMYR)	UEFDOUT	NUC GEN BY OWNERSHIP TYPE /NERC
UGNWDNR(2,MNUMNR,MNUMYR)	UEFDOUT	WIND GEN BY OWNERSHIP TYPE /NERC
UGNWNNR(2,MNUMNR,MNUMYR)	UEFDOUT	WIND GEN BY OWNERSHIP TYPE /NERC
UIALLW(EFD$SO2)	USO2GRP	INITIAL SO2 ALLOWANCES
UNFPH	ECP$CNTL	LENGTH OF FULL PLANNING HORIZON
UNSO2	USO2GRP	NUMBER OF COMPLIANCE GROUPS
UNTCOS(EFDMSP,EFDMPG)	DISPETT	
UNXPH	ECP$CNTL	LENGTH OF EXPL. PLANNING HORIZON
UPBND	ECP$CNTL	BOUND ROW NAME
UPCOEFC(MNUMNR,ECP$NCC)	BILDIN	COEFF-COAL PRC EXP. EQUATIONS
UPCSO2(EFD$SO2)	USO2GRP	CURRENT SO2 PENALTY COST
UPDETT(ECP$DSP)	ECP$CNTL	IRT BLD SW 0=NOT 1=ALLOWED - DSP
UPDLC(ECP$DSP)	ECP$CNTL	LEARNING CURVE - DSP. CAPACITY
UPDMCD(ECP$DSM)	ECP$CNTL	DSM GROUP CODES
UPDNUG(ECP$DSP)	ECP$CNTL	NUG BLD SW 0=NOT 1=ALLOWED - DSP
UPDOPT(ECP$DSP)	ECP$CNTL	TECHNICAL OPT. - DSP. CAPACITY
UPEFPT(ECP$CAP)	ECP$CNTL	EFP TYPE
UPFLCD(ECP$NFL)	ECP$CNTL	FUEL CODES
UPFTYP(ECP$CAP)	ECP$CNTL	FINANCIAL TYPE
UPFUEL(EFDNFL,EFDMFRG)	FUELIN	DELIVERED FUEL PRICES
UPF759(ECP$CAP)	ECP$CNTL	F759 PRIMARY FUEL CODE
UPF860(ECP$CAP)	ECP$CNTL	F860 PRIMARY FUEL CODE

UPGNPD(MNUMYR+ECP$FPH)	ECP$CNTL	GNP DEF.S
UPICAPD(MNUMYR+ECPXPH,ECPINT)	ECP$CNTL	CAP COST DEF.- INT. CAPACITY
UPIETT(ECP$INT)	ECP$CNTL	IRT BLD SW 0=NOT 1=ALLOWED - INT
UPILC(ECP$INT)	ECP$CNTL	LEARNING CURVE - INT. CAPACITY
UPINCD(ECP$INT)	ECP$CNTL	INT. PLANT CODES
UPINUG(ECP$INT)	ECP$CNTL	NUG BLD SW 0=NOT 1=ALLOWED - INT
UPIOPT(ECP$INT)	ECP$CNTL	TECHNICAL OPT. - INT. CAPACITY
UPLDCD(ECP$VLS)	ECP$CNTL	LOAD SEGMENT CODES
UPLSO2(EFD$SO2)	USO2GRP	LAGGED SO2 PENALTY COST
UPMDCD(ECP$VLS)	ECP$CNTL	MODE OF OPERATION CODES
UPM759(ECP$CAP)	ECP$CNTL	F759 PRIME MOVER CODE
UPM860(ECP$CAP)	ECP$CNTL	F860 PRIME MOVER CODE
UPNSO2(EFD$SO2)	USO2GRP	NEXT SO2 PENALTY COST
UPOBJ	ECP$CNTL	OBJECTIVE FUNCTION NAME
UPOLD(EFD$SO2)	USO2GRP	PENALTY COST FROM PREVIOUS NEMS ITER
UPOWNCD(ECP$OWN)	ECP$CNTL	FIN. OWNERSHIP TYPE 1-'U' 2-'N'
UPPCAPD(MNUMYR+ECPXPH,ECPDSP)	ECP$CNTL	CAP COST DEF.- DSP. CAPACITY
UPPLCD(ECP$DSP)	ECP$CNTL	DSP. PLANT CODES
UPRCAPD(MNUMYR+ECPXPH,ECPRNW)	ECP$CNTL	CAP COST DEF.- REN. CAPACITY
UPRCLNR(MNUMNR,MNUMYR)	UEFDOUT	COAL PRICE BY OWNERSHIP TYPE/NERC
UPRDSNR(MNUMNR,MNUMYR)	UEFDOUT	DS PRICE BY OWNERSHIP TYPE/NERC
UPRETT(ECP$RNW)	ECP$CNTL	IRT BLD SW 0=NOT 1=ALLOWED - REN
UPRGCD(MNUMNR)	ECP$CNTL	REGION CODES
UPRGCNR(MNUMNR,MNUMYR)	UEFDOUT	GAS (COMP) PRICE BY OWNERSHIP TYPE/NERC
UPRGFNR(MNUMNR,MNUMYR)	UEFDOUT	GAS (FIRM) PRICE BY OWNERSHIP TYPE/NERC
UPRGINR(MNUMNR,MNUMYR)	UEFDOUT	GAS (INT.) PRICE BY OWNERSHIP TYPE/NERC
UPRHONR(MNUMNR,MNUMYR)	UEFDOUT	REN. PRICE BY OWNERSHIP TYPE/NERC
UPRHS	ECP$CNTL	RIGHT HAND SIDE NAME
UPRLC(ECP$RNW)	ECP$CNTL	LEARNING CURVE - REN. CAPACITY
UPRNCD(ECP$RNW)	ECP$CNTL	REN. PLANT CODES
UPRNUG(ECP$RNW)	ECP$CNTL	NUG BLD SW 0=NOT 1=ALLOWED - REN
UPROPT(ECP$RNW)	ECP$CNTL	TECHNICAL OPT. - REN. CAPACITY
UPRRHNR(MNUMNR,MNUMYR)	UEFDOUT	RH PRICE BY OWNERSHIP TYPE/NERC
UPRRLNR(MNUMNR,MNUMYR)	UEFDOUT	RL PRICE BY OWNERSHIP TYPE/NERC
UPRURNR(MNUMNR,MNUMYR)	UEFDOUT	NUC PRICE BY OWNERSHIP TYPE/NERC
UPSCCD(ECP$SCR)	ECP$CNTL	RETROFIT CLUSTER CODE
UPSRHEL(MNUMCR)	DISPUSEC	AVG SULFUR PENALTY--RH
UPSRLEL(MNUMCR)	DISPUSEC	AVG SULFUR PENALTY--RL
UPSTYR	ECP$CNTL	INITIAL EXECUTION YEAR FOR ECP
UPTCRT	ECP$CNTL	TARGET COV RATIO-PUR. CONSTRAINT
UPVTYP(ECP$CAP)	ECP$CNTL	VINT. TYPE 0=EX. 1=NEW--ECP CAP
UPYRCD(ECP$FPH)	ECP$CNTL	YEAR CODES
UQALLW(EFD$SO2)	USO2GRP	ALLOWANCE FOR SO2
UQCSO2(EFD$SO2)	USO2GRP	CURRENT QUANTITY OF SO2 PRODUCED
UQFCONN(EFD$NFL,MNUMNR,EFD$OWN)	DISPUSE	FUEL CONS BY NERC/OWNER
UQFGENC(EFD$NFL,MNUMCR)	DISPUSE	GEN/FUEL TYPE IN CENSUS REGS
UQFGENN(EFD$NFL,MNUMNR,EFD$OWN)	DISPUSE	GEN/FUEL TYPE IN NERC REGS
UQFSO2(EFD$NFL)	DISPUSE	SO2 CONTENT BY FUEL TYPE
UQFUEL(EFDNFL,EFDMFRG,EFD$OWN)	DISPUSE	FUEL CONS IN FUEL REGIONS
UQHGENC(EFD$RNW,MNUMCR)	DISPUSE	GEN/REN CAPACITY IN FUEL REGS
UQHGENN(EFD$RNW,MNUMNR,EFD$OWN)	DISPUSE	GEN/REN CAPACITY IN FUEL REGS
UQLSO2(EFD$SO2)	USO2GRP	LAGGED QUANTITY OF SO2 PRODUCED
UQNSO2(EFD$SO2)	USO2GRP	NEXT QUANTITY OF SO2 PRODUCED
UQPGENC(EFD$DSP,MNUMCR)	DISPUSE	GEN/DSP CAP IN CENSUS REGS
UQPGENN(EFD$DSP,MNUMNR,EFD$OWN)	DISPUSE	GEN/DSP CAP IN NERC REGS
UQPSO2(EFD$SO2)	USO2GRP	PREVIOUS QUANTITY OF SO2 PRODUCED

UQTDLS(MNUMNR)	DISPETT	
URETTLU(MNUMNR,MNUMYR)	UEFDOUT	UTIL TOTAL RETIREMENTS BY NERC
URGCMAX(EFD$MPG)	DISPUSE	G/O PRC RAT--MAX GAS USE
URGCMIN(EFD$MPG)	DISPUSE	G/O PRC RAT--MIN GAS USE
URGCPAR(EFD$MPG)	DISPUSE	G/O PRC RAT--MAX GAS USE
URNCSI(MNUMNR)	DISPETT	
URNCST(MNUMNR)	DISPETT	
URNCWI(MNUMNR)	DISPETT	
URNCWT(MNUMNR)	DISPETT	
USF759(ECP$CAP)	ECP$CNTL	F759 SECONDARY FUEL CODE
USF860(ECP$CAP)	ECP$CNTL	F860 SECONDARY FUEL CODE
USGCMAX(EFD$MPG)	DISPUSE	MAX GAS SHR--DF PLANTS
USGCMIN(EFD$MPG)	DISPUSE	MIN GAS SHR--DF PLANTS
USGCPAR(EFD$MPG)	DISPUSE	MAX GAS SHR--DF PLANTS
UTCAR(MNUMNR,MNUMYR)	UEFDOUT	TOTAL CAR EMISSIONS BY NERC
UTCARC(EFD$NFL,MNUMCR)	DISPUSE	CAR EMISSIONS BY FUEL/CENSUS
UTCARN(EFD$NFL,MNUMNR)	DISPUSE	CAR EMISSIONS BY FUEL/CENSUS
UTCO1(MNUMNR,MNUMYR)	UEFDOUT	TOTAL CO1 EMISSIONS BY NERC
UTCO1C(EFD$NFL,MNUMCR)	DISPUSE	CO EMISSIONS BY FUEL/CENSUS
UTCO1N(EFD$NFL,MNUMNR)	DISPUSE	CO EMISSIONS BY FUEL/CENSUS
UTCO2(MNUMNR,MNUMYR)	UEFDOUT	TOTAL CO2 EMISSIONS BY NERC
UTCO2C(EFD$NFL,MNUMCR)	DISPUSE	CO2 EMISSIONS BY FUEL/CENSUS
UTCO2N(EFD$NFL,MNUMNR)	DISPUSE	CO2 EMISSIONS BY FUEL/CENSUS
UTDMDE(MNUMNR,MNUMYR)	UETTOUT	NET DOMESTIC ECONOMY SALES-- Nerc (MM$)
UTDMDF(MNUMNR,MNUMYR)	UETTOUT	NET DOMESTIC FIRM POWER -Nerc (MM$)
UTDMME(MNUMNR,MNUMYR)	UETTOUT	NET DOMESTIC ECONOMY SALES-Nerc (Mkwh)
UTDMMF(MNUMNR,MNUMYR)	UETTOUT	NET DOMESTIC FIRM POWER --Nerc (Mkwh)
UTEXDE(MNUMNR,MNUMYR)	UETTOUT	GROSS DOM. ECONOMY SALES--Nerc (MM$)
UTEXDF(MNUMNR,MNUMYR)	UETTOUT	GROSS DOM. FIRM POWER -NErc (MM$)
UTEXME(MNUMNR,MNUMYR)	UETTOUT	GROSS DOM. ECONOMY SALES-Nerc (Mkwh)
UTEXMF(MNUMNR,MNUMYR)	UETTOUT	GROSS DOM. FIRM POWER --NERc (Mkwh)
UTEXPE(MNUMNR,MNUMYR)	UETTOUT	ECONOMY POWER EXPORTS--NERC (Mwh)
UTEXPF(MNUMNR,MNUMYR)	UETTOUT	FIRM POWER EXPORTS--NERC (MW h)
UTIMPE(MNUMNR,MNUMYR)	UETTOUT	ECONOMY POWER IMPORTS--NERC (Mkwh)
UTIMPF(MNUMNR,MNUMYR)	UETTOUT	FIRM POWER IMPORTS--NERC (mwh)
UTJUMP	USO2GRP	MAXIMUM PRICE JUMPS
UTLSO2	USO2GRP	TOTAL SO2 PRODUCED
UTLSO2I	USO2GRP	QUANTITY TOLERANCE
UTNOX(MNUMNR,MNUMYR)	UEFDOUT	TOTAL NOX EMISSIONS BY NERC
UTNOXC(EFD$NFL,MNUMCR)	DISPUSE	NOX EMISSIONS BY FUEL/CENSUS
UTNOXN(EFD$NFL,MNUMNR)	DISPUSE	NOX EMISSIONS BY FUEL/CENSUS
UTPSO2	USO2GRP	PRICE TOLERANCE
UTSO2(MNUMNR,MNUMYR)	UEFDOUT	TOTAL SO2 EMISSIONS BY NERC
UTSO2C(EFD$NFL,MNUMCR)	DISPUSE	SO2 EMISSIONS BY FUEL/CENSUS
UTSO2N(EFD$NFL,MNUMNR)	DISPUSE	SO2 EMISSIONS BY FUEL/CENSUS
UTVOCC(EFD$NFL,MNUMCR)	DISPUSE	VOC EMISSIONS BY FUEL/CENSUS
UTVOCN(EFD$NFL,MNUMNR)	DISPUSE	VOC EMISSIONS BY FUEL/CENSUS
WPFUEL(EFDNFL,EFDMFRG)	DISPUSE	FUEL PRC FR PREVIOUS ITR -1
WPLT$GRP	EMM$PARM	MAXIMUM NUMBER OF PLANT GROUPS PER REGION
WPLT$REC	EMM$PARM	MAXIMUM NUMBER OF PLANT RECORDS
WPLT$RGN	EMM$PARM	MAXIMUM NUMBER OF PLANT REGIONS
WWOP	NCNTRL	WORLD OIL PRICE CASE
XAREA(EFD$MVS)	DISPETT	
XMAP(EFDMSP,ETTMTG,EFD$MVS)	DISPETT	
XPCLELN(MNUMNR,MNXYR)	BILDIN	EXPECTED COAL PRICE--NERC RGN
XPFUEL(EFDNFL,EFDMFRG)	DISPUSE	FUEL PRC FR PREVIOUS ITR -2

YEARPR	NCNTRL	FOR REPORTING, YEAR DOLLARS (EG. 1990)
ZTDMDF(MNUMNR)	DISPETT	Net Domestic Firm Power(MWH)
ZTDMMF(MNUMNR)	DISPETT	Net Domestic Firm Power (MM$)
ZTEXDF(MNUMNR)	DISPETT	Gross Domestic Firm Power (MMW)
ZTEXMF(MNUMNR)	DISPETT	Gross Domestic Firm Power (MM$)
ZTEXPD(MNUMNR)	DISPETT	International Firm Pwr Exports (MM$)
ZTEXPF(MNUMNR)	DISPETTF	Internat Firm Power Exports(MWH)
ZTIMPD(MNUMNR)	DISPETT	Internat Firm Power Imports (MM$)
ZTIMPF(MNUMNR)	DISPETT	Internat Firm Power Imports (MWH)

A-7 Model Outputs

TABLE A-24: OUTPUT VARIABLES DESCRIPTION

Variable	Field	Indices	Units	Subroutine	Output Common	Comments
UTDMMF	Net Domestic Firm Power	MNUMNR,MNUMYR	Mkwh	ETTCOST	UETTOUT	
UTDMME	Net Domestic Economy Sales	MNUMNR,MNUMYR	Mkwh	ETTCOST	UETTOUT	
UTDMDF	Net Domestic Firm Power	MNUMNR,MNUMYR	MM$	ETTCOST	UETTOUT	
UTDMDE	Net Domestic Economy Sales	MNUMNR,MNUMYR	MM$	ETTCOST	UETTOUT	
UTIMPF	Firm Power Imports	MNUMNR,MNUMYR	Mkwh	ETTCOST	UETTOUT	
UTIMPE	Economy Power Exports	MNUMNR,MNUMYR	Mkwh	ETTCOST,ELDISP		UETTOUT
UTEXPF	Firm Power Exports	MNUMNR,MNUMYR	Mwh	ETTCOST	UETTOUT	
UTEXPE	Economy Power Exports	MNUMNR,MNUMYR	Mwh	ETTCOST,ELDISP		UETTOUT
UTEXMF	Gross Domestic Firm Power	MNUMNR,MNUMYR	Mkwh	ETTCOST	UETTOUT	
UTEXME	Gross Domestic Economy Sales	MNUMNR,MNUMYR	Mkwh	ETTCOST	UETTOUT	
UTEXDF	Gross Domestic Firm Power	MNUMNR,MNUMYR	MM$	ETTCOST	UETTOUT	
UTEXDE	Gross Domestic Economy Sales	MNUMNR,MNUMYR	MM$	ETTCOST	UETTOUT	
UGNCLNR	Coal Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
	OWN					
UGNGFNR	Gas (Firm) Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
	1=Utility					
UGNGINR	Gas (Int.) Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
	2=Nonutility					
UGNGCNR	Gas (Comp.) Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNDSNR	DS Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNRLNR	RL Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNRHNR	RH Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNURNR	Nuc Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNPSNR	PS Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNHYNR	Hyd (Not PS) Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNGENR	Geothermal Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNMSNR	MSW Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNWDNR	Wind Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNSONR	Solar Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNPVNR	Photovoltaic Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNWNNR	Wind	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNHONR	Hyd/Other Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UGNTLNR	Total Generation	OWN,MNUMNR,MNUMYR		GWH	EMMDSPO	UEFDOUT
UFLCLNR	Coal Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UFLGFNR	Gas (Firm) Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UFLGINR	Gas (Int.) Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UFLGCNR	Gas (Comp) Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UFLDSNR	DS Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UFLRLNR	RL Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UFLRHNR	RH Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UFLURNR	Nuc Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UFLPSNR	PS Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UFLHYNR	Hyd (Not PS) Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UFLOTNR	Oth Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UFLTLNR	Total Consumption	OWN,MNUMNR,MNUMYR		MMM Btu	EMMDSPO	UEFDOUT
UPRCLNR	Coal Price	MNUMNR,MNUMYR			EFDOUT	

UPRGFNR	Gas (Firm) Price	MNUMNR,MNUMYR			UEFDOUT	
UPRGINR	Gas (Int) Price	MNUMNR,MNUMYR			UEFDOUT	
UPRGCNR	Gas (Comp) Price	MNUMNR,MNUMYR			UEFDOUT	
UPRDSNR	DS Price	MNUMNR,MNUMYR			UEFDOUT	
UPRRLNR	RL Price	MNUMNR,MNUMYR			UEFDOUT	
UPRRHNR	RH Price	MNUMNR,MNUMYR			UEFDOUT	
UPRURNR	Nuc Price	MNUMNR,MNUMYR			UEFDOUT	
UPRHONR	Renewables Price	MNUMNR,MNUMYR				
U				EFDOUT		
UTSO2	Total SO2 Emissions	MNUMNR,MNUMYR	Tons	EMMDSPO	UEFDOUT	
UTNOX	Total NOX Emissions	MNUMNR,MNUMYR	Tons	EMMDSPO	UEFDOUT	
UTCO2	Total CO2 Emissions	MNUMNR,MNUMYR	Tons	EMMDSPO	UEFDOUT	
UTCO1	Total CO1 Emissions	MNUMNR,MNUMYR	Tons	EMMDSPO	UEFDOUT	
UTCAR	Total CAR Emissions	MNUMNR,MNUMYR	Tons	EMMDSPO	UEFDOUT	
URETTLU	Utility Total Retirements	MNUMNR,MNUMYR		EMMCAPO	UEFDOUT	
UGNUBCR	Util BWR Nuclear Generation	MNUMCR,MNUMYR			UEFDOUT	
UGNUPCR	Utility PWR Nuclear Generation	MNUMCR,MNUMYR			UEFDOUT	
QBCELNR	VLS Bit Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QBDELNR	LS Bit Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QBMELNR	MS Bit Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QBHELNR	HS Bit Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QSCELNR	VLS Sub Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QSDELNR	LS Sub Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QSMELNR	MS Sub Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QSHELNR	HS Sub Coal consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QLCELNR	VLS Lig Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QLDELNR	LS Lig Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QLMELNR	MS Lig Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QLHELNR	HS Lig Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QBTELNR	Bit Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QSTELNR	Sub Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QLTELNR	Lig Coal Consumption	NDREG,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
FLAGSO2	Penalty Cost Flag	None	Numeric	ELEFD	UEFDOUT	
		0=Not,1=Converged				
FBTELNR	Bit Coal Convergence Flag	NDREG			UEFDOUT	
FSTELNR	Sub Coal Convergence Flag	NDREG			UEFDOUT	
FLTELNR	Lig Coal Convergence Flag	NDREG-1			UEFDOUT	
QGFELGR through 21	NG Firm Consumption	NGTDM,MNUMYR	MMM Btu	MMDSPO	UEFDOUT	NGTDM=1
QGIELGR	NG Inter. Consumption	NGTDM,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	
QGCELGR	NG Comp. Consumption	NGTDM,MNUMYR	MMM Btu	EMMDSPO	UEFDOUT	

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. This subroutine also checks if the dispatch decision has converged on the emissions limit specified by the Clean Air Act Amendments of 1990. If the result has not converged, the emissions penalty cost is changed and the dispatch decision is re-executed.

Called by: UTIL

Source Code: UEFD

Calls: GETSO2, GETIN, GETBLD, GETOUT, ELSO2F, ELDISP, STROUT, STRBLD, ELSO2L,ETTPRC, STRSO2,

Equations: None

Description: The Subroutine GETSO2 reads in total SO_2 produced from the file &6005PRJ.UTIL.SO2DAF.<scenario>. <datekey>[26] for the current year.

Called by: ELEFD

Source Code: UDAF

Calls: --

Equations: None

[26] The final model run for AEO 1994 is: scenario name - AEO94B; datekey - D1221934.

Subroutine: GETIN

Description:	This subroutine reads in load curve, plant grouping, transmission constraints, and cost and performance data from the file &6005PRJ.UTIL.INPTDAF.<scenario>.<datekey>. 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 Code:	UDAF
Calls:	--
Equations:	None

Subroutine: GETBLD

Description: This subroutine reads in the file &6005PRJ.UTIL.ECPIDAF.<scenario>.<datekey> file 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 Code: UDAF

Calls: --

Equations: None

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 Code: UEFD

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

Equations:

<u>Determine the Merit Order for Dispatching</u>

See discussion of the Subroutine ELMRIT

<u>Adjust available capacity for each time period by the planned maintenance schedule</u>

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)

<u>Convert International Trade Power into gigawatts for each Season</u>

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 / TOTHRS
EXPANN = ETEXPE / TOTHRS

and,

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

<u>Adjust Load Curve to Account for Firm Domestic Trade Commitments and for International Economy Trade</u>

ETYVAL(IVCT) = ELYVAL(IVCT,I) + EEITAJ (I) + INTRUP

Where,

ELYVAL = Y value of Seasonal Load Curve where X is time and Y is GW.
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) = (ETXVAL(IVCT+1) - ETXVAL(IVCT)) * .05 * (ETYVAL(IVCT) + ETYVAL(IVCT+1))

ETXVAL = X point on original demand curve (GW), where X is time and Y is GW.
ETYVAL = Y value on original demand curve (GW), where X is time and Y is GW.
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 = ETYVAL + TRNCWT (Winter)
TIYVAL = ETYVAL - TRNCWI (Winter)
TTYVAL = ETYVAL + TRNCST (Summer)
TIYVAL = ETYVAL - TRNCSI (Summer)

Where,

ETYVAL = Y value on original demand curve
TRNCWT = Winter Export Transmission Constraint
TRNCWI = Winter Import Transmission Constraint
TRNCST = Summer Export Transmission Constraint
TRNCSI = Summer 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) = (ETXVAL(IVCT+1) - ETXVAL(IVCT)) * .05 * (ETYVAL(IVCT) + ETYVAL(IVCT+1))

Allocate Capacity to Meet Demand

See discussion of the Subroutine ELALOC.

Calculate Trade Amounts Available to Replace Native Supply

***Need additional discussion

The export and import capacity available for trade is calculated by subtracting the area of the original demand curve from the export load curve and by subtracting the import load curve from the original demand curve, respectively.

CUMAREA = AREATT - AREANT (Export Available)
CUMAREI = AREANT - AREAIT (Import Available)

Where,

AREATT = Area under the export load curve
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.

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 Code: UEFD

Calls: ELFSHR

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

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. The sort is completed as follows:

```
   Do 30 I = 1, ECNTP
   INDEX(I)=I
30 CONTINUE

   ILST=ECNTP-1
   DO 60 I=1,ILST
     JFRST = I + 1
   DO 50 J=JFRST, ECNTP
   IF (UNTCST(J).GE.UNTCST(I))GO TO 40
     TEMP=UNTCST(J)
```

```
      UNTCST(J)=UNTCST(I)
      UNTCST(I)=TEMP
      ITEMP=INDEX(J)
      INDEX(J)=INDEX(I)
      INDEX(I)=ITEMP
40    CONTINUE
50    CONTINUE

60    CONTINUE
```

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 Code: UEFD

Calls: --

Equations:

Determine Weights for Seasonal Fuel Shares

SWGHT(JSP) = EESSHR(JSP) * ECCAP(I,JSP)
TWGHT = TWGHT + SWGHT(JSP)

Where,

EESSHR = Seasonal Demand Share
ECCAP = Conventional Capacity
I = Capacity Type
JSP = Season

SWGHT(JSP) = SWGHT(JSP) / TWGHT

ECFSHR(I,J)=ECFSHR(I,J) + ECMFSH(IPGRP,J,JSP) * SWGHT(JSP)
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))

Add Parity Stuff

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

Calls: --

Equations:

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

Add in Hydroelectric Capacity

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

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

During the Winter Seasons, the peak is calculated as follows:

PEAK(ISP) = ELYVAL(1,ISP) + INTRUP + EEITAJ(ISP) + TRNCWT

While during the Summer Seasons, the peak is calculated as:

PEAK(ISP) = ELYVAL(1,ISP) + INTRUP + EEITAJ(ISP) + TRNCST

Where,

ELYVAL = Y value on original demand curve (GW), where X is time and Y is GW.
EEITAJ = Net Exports
TRNCWT = Winter Export Transmission Constraint
TRNCST = Summer Export Transmission Constraint

If the Trade Model is not Executing, the peak is calculated as:

PEAK(ISP) = ELYVAL(1,ISP) + INTRUP + EEITJA(ISP)

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

<u>Determine the Maximum Reserve Margin Which Can Be Achieved</u>

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

<u>Determine Seasonal and Annual Maintenance Time Availability Measured in Potential Energy Lost to Maintenance</u>

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)

<u>Schedule Maintenance from the Seasonal Period with the Largest Reserve Margin to the Seasonal Period with the Smallest Reserve Margin</u>

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)

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

Calls: ELGETY

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>Calculate the X-value exactly between each point on the load curve</u>

A_CRV(IVCT) = ETXVAL(IVCT+1) + ETXVAL(IVCT)) * .5

Where,

ETXVAL = X value of the point which defines the load curve, where the x value represents time and the y value represents demand (gw).
IVCT = Number of points which define the load curve.

<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), ETYVAL(1))
R_AREA = EHCAP(IRNW,ISP) * 0.001 * X_VAL

S_CAP = R_CAP
S_AREA = R_AREA

Where,

EHCAP(IRNW,ISP) =Renewable Capacity

ETYVAL = y value of the point which defines the load curve, where the x value represents time and the y value represents demand (gw).
X_VAL = Real(KHYCF) = EHHYCF(IRNW,ISP) = 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).

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.)

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.

Called by: ELDISP

Source Code: UEFD

Calls: ELGETY, ELLOAD, ETLOAD, EILOAD

Equations:

Initialize Capacity Bound Trigger Points (Minimum Capacity Factors for Available Capacity) and Capacity Switches

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
(i.e. where ESLCUT(1) < CPIVOT)

CPIVOT = YPVPNT(NT) - XPVPNT(NT)*ESLCUT(2) - TOLRNC

Where,

YPVPNT = y value associated with the maximum capacity factor (x value)
NT = Trigger Number
ESLCUT = Line which describes the capacity, y intercept (index = 1) and slope (index = 2)
TOLRNC = .000001

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 Subroutines ELLOAD, ETLOAD and EILOAD

Update Intercept and Slope of Current Cutting Line
ESLCUT(1) = ESLCUT(1) + SHGHT(SOLSW)
ESLCUT(2) = ESLCUT(2) - SHGHT(SOLSW) * SLFR(SOLSW) * 2.0

Where,

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

Store Dispatch Decision

Update Cumulative Load Satisfied

Check if Total Demand Has Been Met

Turn Capacity Off if All Capacity Has Been Met

Index to the Next Capacity Type in the Merit Order

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

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.

Called by: ELALOC

Source Code: UEFD

Calls: ELGETXY

Equations:

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

CUT(1) = ESLCUT(1) + SHGHT
CUT(2) = ESLCUT(2) - SHGHT * 2 * SLFR
Where:

CUT(1) = intercept of cutting line
CUT(2) = intercept

ELGTXY is called to find where the cutting line crosses the load curve.

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) > TIYVAL
AREANT(HN,IE-1) = .5 ((CUT(1) + CUT(2) * ETXVAL(IE-1))) +
(CUT(1) + CUT(2) * ETXVAL(IE))) * (ETXVAL(IE) -
ETXVAL(IE-1))

If the cutting line is below the load curve (IABOVE = 0), area is calculated under the cutting line from the intersection of the Y-axis (ISTRT) to the intersection point of the load curve and the cutting line (XINT,YINT), and area is added from under the load curve from the intersection point of the load curve and the cutting line (XINT,YINT) to the knee (XVAL(INTNUM+1)).

If before the crossover point:

AREANT(HN,IE-1) = .5 ((CUT(1) + CUT(2) * ETXVAL(IE-1)) +
(CUT(1) + CUT(2) * ETXVAL(IE))) *
(ETXVAL(IE) - ETXVAL(IE-1))

If left of the crossover point:

AREANT(HN,INTNUM) = .5 (CUT(1) + CUT(2) * ETXVAL(INTNUM) + YINT) * (XINT - ETXVAL(INTNUM))

If right of the crossover point:

AREANT(HN,INTNUM) = AREANT + .5(YINT + ETYVAL(INTNUM+1)) * (ETXVAL(INTNUM+1) - XINT)

If the cutting line is above the load curve, area is calculated under the load curve from the intersection of the Y-axis (ISTRT) to the intersection of the cutting line and the load curve (XINT,YINT), and area is added from under the cutting line from the intersection of the cutting line and the load curve (XINT,YINT) to the knee (INTNUM + 1).

If before the crossover point:

AREANT(HN,I) = .5 (ETYVAL(I) + ETYVAL(I+1)) *
(ETXVAL(I+1) - ETXVAL(I))

If left of the crossover point:

AREANT(HN,INTNUM) = (YINT + ETYVAL(INTNUM) * .5 * (XINT - ETXVAL(INTNUM))

If right of the crossover point:

AREANT(HN,INTNUM) = AREANT + .5 (YINT + CUT(1) + CUT(2) * ETXVAL(INTNUM+1)) * (ETXVAL(INTNUM+1) - XINT)

Figure B-1

PLACE DANA'S DIAGRAM HERE Calculation of Area under Load Curve

Description: This subroutine evaluates a piecewise 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: ELRNEW

Source Code: UEFD

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:

Determine relative position of the x value

XSHR = X / (ETXVAL(ETNVCT)-ETXVAL(1))

Where,

ETXVAL(ETNVCT) = Last x value which defines the load duration curve.
ETXVAL(1) = First x value which defines the load duration curve.

Determine First X Coordinate on Load Curve to Search for Pair

IFRST = MAX(DBL(1.0) , ETNVCT * XSHR)

If the input x value is greater than IFRST, search for the x,y pair from IFRST to the last x,y pairs that defines the load curve. Once the location on the load curve is determined, the y-value is calculated as follows:

YOUT = ETYVAL(I) - ((ETYVAL(I)-ETYVAL(I+1)) * (ETXVAL(I)-X) / (ETXVAL(I) - ETXVAL(I+1)
IOUT = I

Where,

ETYVAL = y value of the x,y pair that define a point on the demand curve
ETXVAL = x value of the x,y pair that define a point on the demand curve
I = Step on the Load Curve

If the input x value is less than IFRST, search for the x,y pair from IFRST to the second point on the load curve. Once the location on the load curve is determined, the y-value is calculated as follows:

YOUT = ETYVAL(I) - ((ETYVAL(I)-ETYVAL(I+1)) * (ETXVAL(I)-X) / (ETXVAL(I) - ETXVAL(I+1)
IOUT = I

Subroutine: ETLOAD

Description: This subroutine calculates the load under the "export" load duration curve and saves the information into the variable AREATT. As in ELLOAD, the point at which the lines which defines the capacity being dispatched crosses the load duration curve needs to be determined. This is calculated in the following subroutine

Called by: ELALOC

Source Code: UETT

Calls: --

Equations: Similar to ELLOAD subroutine. See ELLOAD subroutine for mathematical description.

Interim calculations are performed to collect information regarding the area under the curves that is available for export or that could be displaced.

Area available for export is calculated as:

CUMAREA = AREATT - AREANT

where

CUMAREA = cumulative area available for export
AREATT = all area under "export" curve
AREANT = all area under original curve

Incremental areas are calculated as:

EXTMP = CUMAREA(current) - CUMAREA(previous)

where
EXTMP = incremental area (horizonal/vertical) available for export

Last, since less than 30 of the 180 or so possible plant groups that are allocated are generally available for trade, the above data are stored into arrays dimensioned only by 30 horizontal slices. The original horizontal slice index is saved into a mapping variable for later use. The following describes the data elements preserved for the ETT.

<u>Exports</u>

- EXMAP - map to original horizontal slice index
- AREATR = EXTMP * EETIME (generation)
- CAPTR = AREATR / [(ETXVAL(next) - ETXVAL(current)) * EETIME]

Next, ELCOST is called to store non-trade dispatch summary results and to store some pointers needed later in the trade algorithm.

Pointers preserved include:

ECDSPN = horizonal slice index
ECDSPT = equipment type index
ECASTS = capacity type
ECFSHR = fuel share index

STRETT is called to write out the ETTDAF (stores trade opportunities arrays into DAF).

Description: This subroutine evaluates a piecewise load duration curve to find the x,y pair and step I at which a given cutting line crosses the load duration curve.

Called by: ELLOAD

Source Code: UEFD

Calls: --

Equations:

<u>If the Cutting Line is Below the Load Duration Curve</u>

Given the equation of the line, determine the y-value for each x-value along the line.

YINT = Y0 + SLOPE * ETXVAL(I+1)

Where,

Y0 = The y-intercept of the line
SLOPE = Slope of the Line
ETXVAL = The x value of the x,y pair that define points on the load curve.

If the resulting y-value (on the line) is greater than the y-value which defines the load duration curve then the x,y pair and step are defined as:

XINT = ((ETYVAL(I) - Y0) * (ETXVAL(I+1) - ETXVAL(I)) + ETXVAL(I)*(ETYVAL(I)-ETYVAL(I+1))) / (SLOPE * (ETXVAL(I+1)-ETXVAL(I)) + ETYVAL(I)-ETYVAL(I+1)))
YINT = YO +SLOPE*XINT
IOUT = I

If the resulting y-value (on the line) is never greater than any y-value which defines the load duration curve, then the line crosses the load duration curve at the last point; i.e. the x,y pair and the step are defined as:

IOUT = ETNVCT
YINT = Y0 + SLOPE * ETXVAL(ETNVCT)
XINT = ETXVAL(ETNVCT)

<u>If the Cutting Line is Above the Load Duration Curve</u>

The algorithm searches through each point on the load duration curve and checks if the line crosses, i.e., is the y value on the line less than the y value on the load duration curve. Since the line began with the y value greater than the y value on the load curve, the line must intersect the load curve at the first point at which the y value on the line is less than the y value on the load curve. When this occurs, the x,y pair and the step number are defined as:

XINT = ((ETYVAL(I) - Y0) * (ETXVAL(I+1) - ETXVAL(I)) + ETXVAL(I) * (ETYVAL(I) - ETYVAL(I+1))) / (SLOPE * (ETXVAL(I+1)-ETXVAL(I)) + ETYVAL(I) - ETYVAL(I+1)))
YINT = Y0 + SLOPE *XINT
IOUT = I

If the y-value on the line is never less than the y-value on the next step in the load curve, the line must cross the curve in the last step; i.e.,

```
IOUT = ETNVCT
YINT = ETYVAL(ETNVCT)
XINT = ETXVAL(ETNVCT)
```

Description: This subroutine also calculates the load under the "import" load duration curve and saves the information into the variable AREATI. As in ELLOAD, the point at which the lines which defines the capacity being dispatched crosses the load duration curve needs to be determined. This is calculated in the following subroutine.

Called by: ELALOC

Source Code: UETT

Calls: ELITXY

Equations: Similar to ELLOAD subroutine. See Mathematical Description for ELLOAD.

Area available for displacement is calculated as:

CUMAREI = AREANT - AREAIT

where

CUMAREI = cumulative area that could be displaced
AREAIT = all area under "import" curve
AREANT = all area under original curve

Incremental areas are calculated as:

IMTMP = CUMAREI(current) - CUMAREI(previous)

where

IMTMP = incremental area (horizonal/vertical) available for displacement

Last, since less than 30 of the 180 or so possible plant groups that are allocated are generally available for trade, the above data are stored into arrays dimensioned only by 30 horizontal slices. The original horizontal slice index is saved into a mapping variable for later use. The following describes the data elements preserved for the ETT.

<u>Area available to be displaced</u>

- IMMAP - map to original horizontal slice index
- AREATI = IMTMP * EETIME (generation)
- CAPTRI = AREATI / [(ETXVAL(next) - ETXVAL(current)) * EETIME]

Next, ELCOST is called to store non-trade dispatch summary results and to store some pointers needed later in the trade algorithm.

Pointers preserved include:

ECDSPN = horizonal slice index
ECDSPT = equipment type index
ECASTS = capacity type
ECFSHR = fuel share index

STRETT is called to write out the ETTDAF (stores trade opportunities arrays into DAF).

Description: This subroutine evaluates a piecewise linear load duration curve to find a x,y pair and step I at which a given cutting line crosses the import load duration curve.

Called by: EILOAD

Source Code: UETT

Calls: --

Equations: See discussion of ELGTXY. The algorithm is the same in the ELTTXY subroutine, however, the y-value which describes the load curve is the y value for the original load curve less the seasonal transmission capacity.

Subroutine: ELTTXY

Description: This subroutine evaluates a piecewise load duration curve to find the x,y pair and step I at which a given cutting line crosses the export load duration curve.

Called by: ETLOAD

Source Code: UETT

Calls: --

Equations: See discussion of ELGTXY. The algorithm is the same in the ELTTXY subroutine, however, the y-value which describes the load curve is the y value for the original load curve plus the seasonal transmission capacity.

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

Called by: ELDISP

Source Code: UEFD

Calls: --

Equations:

<u>Add Plant Group Data to Running Totals</u>

Capacity

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

Where,

ECDSPC = Capacity in Each Horizontal Slice

Generation Totals - By Season and Ownership

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

Where,

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

<u>Calculate Fuel Consumption, Emissions and O&M Costs</u>

Fuel Consumption

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

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

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

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

<u>Aggregate Totals</u>

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

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

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

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

Where,

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

SO_2 Emissions
UTSO2N(IFLTP,INR) = UTSO2N(IFLTP,INR) + FUEL * UFRSO2(IFLTP,IFLRG) * (1.0 - UFRASH(IFLTP)) * (1.0 - REAL(KSCRB) * EFACTR) * 0.5

NO_x Emissions
UTNOXN(IFLTP,INR) = UTNOXN(IFLTP,INR) + FUEL * UFRNOX(IFLTP,IFLRG) * 0.5

CO_2 Emissions
UTCO2N(IFLTP,INR) = UTCO2N(IFLTP,INR) + FUEL * UFRCO2(IFLTP,IFLRG) * 0.5

Carbon Emissions
UTCARN(IFLTP,INR) = UTCAR(IFLTP,INR) + FUEL * UFRCAR(IFLTP,IFLRG) * 0.5

CO_1 Emissions
UTCO1N(IFLTP,INR) = UTCO1(IFLTP,INR) + FUEL * UFRCO1(IFLTP,IFLRG) * 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
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

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

Calculate Commercial Nonutility Revenues (Sold to Utilities)

Calculate Generation and Capacity Sold to Utilities

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

Where,

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

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

Where,

CGCOMPF = Commercial Cogen Fixed Cost

Calculate Industrial and Other Nonutility Revenues

Calculate Industrial and Other, Generation and Capacity Sold to Utilities

Generation
TOTGENI = TOTGENI + (ISHARE(IRG,K) * (CGINDGEN(K,IYR,I,1)))
TOTGENO = TOTGENO + (CGOTGEN(IRG,IYR,I)/1000)

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

Revenues
LOCRIC = LOCRIC + (EWGAVP * TOTGENI) + (CGINDPF * TOTCAPI) + CGOTPV * TOTGENO) + (CGOTPF * TOTCAPO)

Where,

ISHARE = Census to NERC region map
CGINDGEN = Industrial Cogeneration (Energy)
K = Census Division
IYR = Model Year
I = Fuel Type
CGOTGEN = Generation at Other Cogen Facilities (i.e., not industrial or commercial)
CGINDCAP = Industrial Cogen Capacity
L = Vintage (Existing/Planned or Unplanned)
CGOTCAP = Other Cogen Capacity (i.e., not industrial or commercial)
CGINDPF = Industrial Fixed Component Price
CGOTPV = Other Cogen Variable Component Price

CGOTPF = Other Cogen Fixed Component Price

Calculate Revenues from International Electricity Trade

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

Where,

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

Subroutine: STRETT

Description: This subroutine captures the area available for displacement and the area available for export by region, season and vertical and horizontal slice into the file &6005PRJ.UTIL.ETTDF.<scenario>. <datekey>.

Called by: ELDISP

Source Code: UDAF

Calls: --

Equations: None

Subroutine: ELSO2N

Description: This subroutine accumulates SO_2 emissions and allowances across regions for each compliance group.

Called by: ELEFD

Source Code: UEFD

Calls: --

Equations: None

Subroutine: STROUT

Description: This subroutine store the results of the dispatch decision in the file &6005PRJ.UTIL.OUTDAF.<scenario>.<datekey>.

Called by: ELEFD

Source Code: UDAF

Calls: --

Equations: None

Subroutine: STRBLD

Description: This subroutine store the build decision information in the file &6005PRJ.UTIL.ECPIDAF. <scenario>.<datekey>.

Called by: ELEFD

Source Code: UDAF

Calls: --

Equations: None

Subroutine: ELSO2L

Description:	This subroutine checks to see if the emission meet the allowances in each of the compliance groups.
Called by:	ELEFD
Source Code:	UEFD
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 &6005PRJ.UTIL.ETTIN.AEO93B.D1111931 and trade variables are initialized.

Called by: ELEFD

Source Code: UETT

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.

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

Calls: GETETT, GETIN

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: 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

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

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

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

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

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

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

Calls: GETOUT, GETBLD, GETIN, ELFSHRS, STROUT, STRBLD

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.

ECAPPS = ECAPPS + ETCAPN - ETCAPO
EQGEN = 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)

Outputs

DISPOUT

Variable Description	Variable Name	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
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

Subroutine: GETOUT

Description:	This subroutine opens the file &6005PRJ.UTIL.OUTDAF.<scenario>.<datekey>.
Called by:	ETTCOST, ELEFD
Source Code:	UDAF
Calls:	--
Equations:	None

Subroutine: STROUT

Description: This subroutine store the results of the dispatch decision in the file &6005PRJ.UTIL.OUTDAF.<scenario>.<datekey>.

Called by: ETTCOST, ELEFD

Source Code: UDAF

Calls: —

Equations: None

Subroutine: STRBLD

Description: This subroutine store the build decision information in the file &6005PRJ.UTIL.ECPIDAF. <scenario>.<datekey>.

Called by: ETTCOST, ELEFD

Source Code: UDAF

Calls: --

Equations: None

Subroutine: ELSO2L

Description: This subroutine checks to see if the emission meet the allowances in each of the compliance groups.

Called by: ELEFD

Source Code: UEFD

Calls: --

Equations: None

Subroutine STRSO2

Description: This subroutine saves information temporarily stored in the common block USO2GRP in the file &6005PRJ.UTIL. SO2DAF.<scenario>.<datekey>, in particular, the total SO_2 produced, the penalty cost, and the SO2 allowances.

Called by: ELEFD

Source Code: UDAF

Calls: --

Equations: None

Appendix C

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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.[27] 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.[28] 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.[29] 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.

The CAAA also requires the Environmental Protection Agency (EPA) to set new NO_x emission standards for existing and new utility boilers.

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

[28]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.

[29]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.

For existing tangentially-fired boilers[30] 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[31] (excluding cell-burner technology[32]) the maximum is 0.50 pounds per million Btu. These new standards must be met by 1995. For cyclones,[33] wet-bottom wall-fired boilers,[34] 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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[30]Tangentially-fired boilers are fired from the corners of the furnace; the fireball can be directed upward or downward.

[31]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.

[32]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.

[33]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.

[34]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. Limits on 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 1993

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:** Patricia Toner
- **Telephone:** (202) 586-2048

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:

Argonne National Laboratories under contract to 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 1992*, (DOE/EIA-0349(92)), draft report, 1994.

- Historic (1990, 1991, and 1992) 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

- 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 3090 mainframe
- **Operating System:** MVS
- **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.

Status of Evaluation Efforts by Sponsor: The EFD documentation is currently undergoing independent expert review. The office is also involved in completing Volume II of the documentation, the Model Developers Report, which will provide sensitivity analysis and scenario output in support of the documentation of model performance. The Model Developers Report is scheduled to be completed in December 1994.

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(91)), 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:

Losses = ((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.

This variable needs further research and will be included in the sensitivity analysis in Volume II of the Documentation, *The Model Developers Report.*

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 Argonne National Laboratory 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

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