Appendix C

Policy Office Electricity Modeling System (POEMS) Documentation

Contents

Introduction

The Policy Office Electricity Modeling System (POEMS) is a modeling system that integrates the Energy Information Administration's National Energy Modeling System (NEMS) with the detailed electricity market model, TRADELEC™, developed by OnLocation, Inc. In POEMS, TRADELEC™ substitutes for the Electricity Market Module (EMM) of the NEMS and provides an alternative electricity model with more detail and disaggregation. TRADELEC™ was designed specifically for analyzing competitive electricity markets and the transition from regulated markets. It incorporate the features necessary to analyze key policy questions: stranded costs, consumer prices, mix of new construction, and interaction with environmental policies.

POEMS has been used as an analysis tool for a variety of clients and studies. It is being used to support the Department of Energy's analysis of the Administration's proposed Comprehensive Electricity Competition Act. For various participants in electricity markets, POEMS has been used to perform regional market assessments, such as forecasting electricity prices, supply, and demand under alternative economic and fuel price environments. The model has also been used to assess the impact of alternative environmental policies on utility industry capital turnover and inter-fuel substitution.

The purpose of this report is to document the features of TRADELEC™ and to describe how POEMS brings TRADELEC™ and NEMS together into a seamless, integrated energy modeling system. The first chapter of this report provides an overview of both the POEMS modeling system and the TRADELEC™ electricity model. Because NEMS is fully documented elsewhere by the Energy Information Administration, this report describes it only in brief. The second chapter provides a more detailed description of the TRADELEC™ electricity model features and the variety of assumptions behind its structure. The third chapter gives a summary of the various structural assumptions and various scenario assumptions of the POEMS. The fourth chapter describes a variety of model inputs and data and shows some general input and data values in a series of tables. Appendix A gives more detail with respect to regional inputs to the model.

Overview of POEMS

POEMS integrates two existing models, the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) and TRADELEC™, a detailed competitive electricity market model designed by OnLocation, Inc., to represent regulated and competitive markets and the transition between them. OnLocation, Inc., has incorporated the TRADELEC™ model into the NEMS modeling system to assist the Department of Energy's Office of Economic, Electricity, and Natural Gas Analysis. POEMS is an extended system that allows a detailed study of the transformation of the electric power industry within the context of the other energy markets. This can be especially important if restructuring or other policy scenarios lead to significant changes in electricity prices, which would affect demand, or create shifts among fuel sources, which would affect fuel prices.

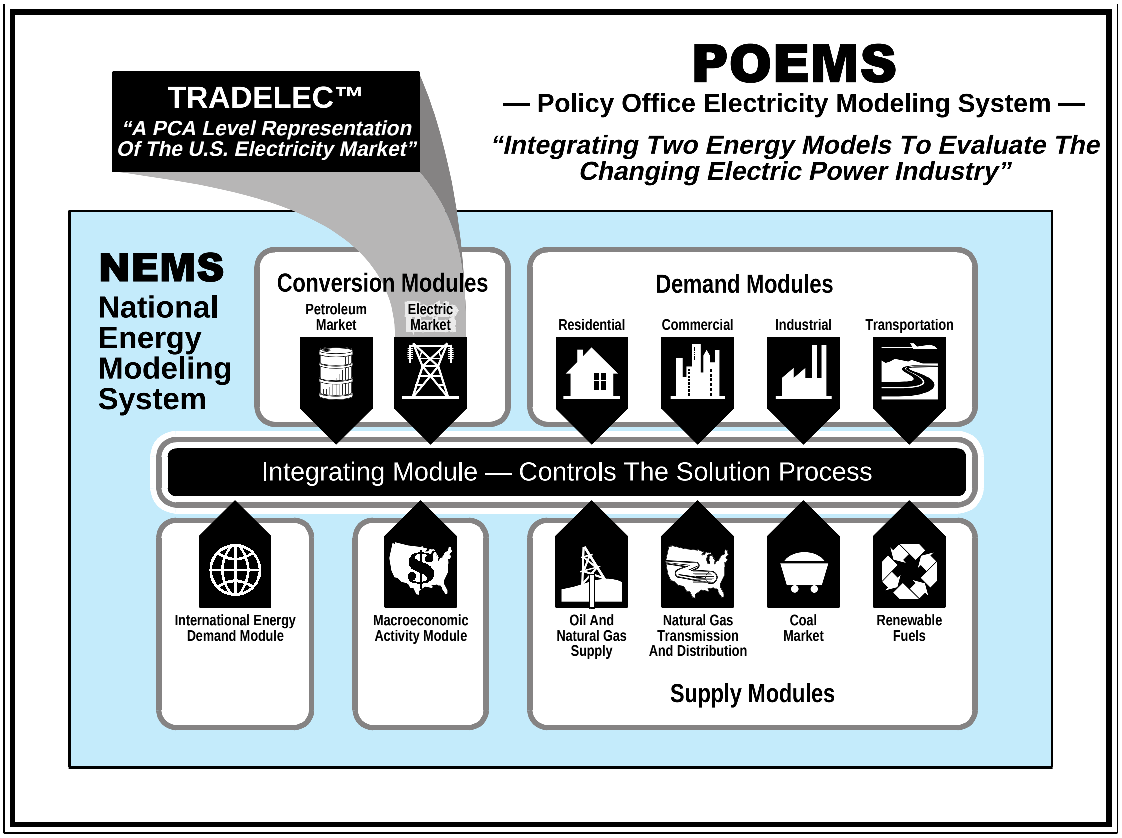
Alternative pricing mechanisms in TRADELEC™ can be used to examine traditional cost-of-service rate regulation, performance-based rate-setting, and market rates. Other competitive market issues addressed by the model include the impact of increased trading of electricity, changes in the technology mix of generation and capacity, transitional cost recovery of existing above market assets, and environmental emissions. The level of detail is considerably greater than many other policy models. The database contains every power plant in the country, trade and dispatch are simulated by power control area (PCA), and electricity demands are addressed seasonally (6 to 12 seasons) and within seasons (12 to 72 typical time of day demand levels).

National Energy Modeling System (NEMS)

The National Energy Modeling System (NEMS) is an energy-economy modeling system of U.S. energy markets. NEMS provides projections of production, imports, conversion, consumption, and prices of energy subject to assumptions regarding macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological cost criteria, cost and performance characteristics of energy technologies, and demographics. NEMS is the modeling system developed and maintained by the Energy Information Administration (EIA) that is used by EIA to produce the annual baseline energy forecasts published in the Annual Energy Outlook (AEO). It can also be used as a tool for energy policy analysis related to existing and proposed changes in a wide variety of laws and regulations related to energy production and use, environmental protection, environmental requirements, or tax provisions. EIA provides extensive documentation for all the components of NEMS.

NEMS is modular in structure as shown in Figure 1. On the supply side, there are separate modules for oil and gas supply, gas transmission, coal markets, and renewable fuels. On the demand side, each end-use sector (residential, commercial, industrial, and transportation) is represented, with inter-fuel competition to meet end-use demands as appropriate. The electricity supply and distribution and petroleum refining sectors are classified as conversion modules. An integrating module interacts with these three categories of modules, together with modules representing the macro-economy and international energy markets. The integrating module controls the solution process, iterating the individual models until convergence representing equilibrium in the producing and consuming sectors is achieved.

Figure 1. Overview of POEMS

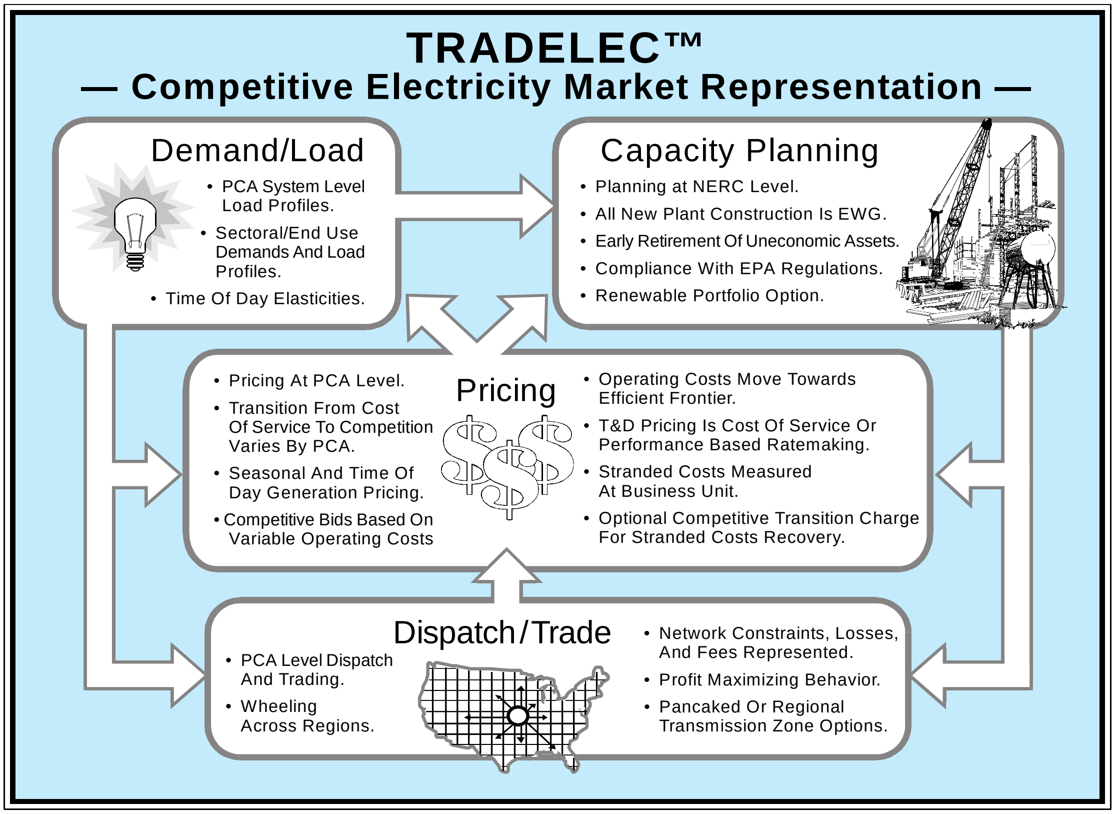


TRADELEC ™ Electricity Model

Because the NEMS is designed for a wide variety of forecasting and policy issues, the level of detail provided in each NEMS module may be constrained towards this general use. NEMS has been very successful at addressing a variety of issues, but POEMS is more narrowly aimed at addressing specific questions surrounding electricity markets. To address these electricity market questions, there are significant advantages to a more disaggregated representation of the electricity sector as in TRADELEC™. The approach taken in POEMS is to substitute TRADELEC™ for the electricity market module (EMM) in NEMS. Depending on the focus of the analysis, TRADELEC™ is run in conjunction with a relevant subset of NEMS modules, such as the various demand modules and the natural gas modules. An overview of the TRADELEC™ electricity model is shown in Figure 2.

Detailed models of the power industry have long been used to help focus operational and policy insights. One hallmark of these models is detailed treatment of the computations needed to calculate historical embedded cost-of-service prices. As regulation changes, these models are revised and extended to capture new events. The reorganization of the electric industry to include competitive generation markets will eventually simplify this modeling task. Electricity prices will

Figure 2: Components of the TRADELEC Model



In the absence of transmission constraints, electricity prices nationwide would converge to a single value with local delivery prices varying only by differences in the cost of transmission (including line losses) and distribution services. However, the tendency in competitive markets toward a single price does not mean that there will be no market separation. Because transmission is neither unconstrained nor without cost, separable regional electricity markets are likely to be observed as model solutions evolve. Additional regional constraints, such as regional specific pollution abatement measures could further increase regional price differences even with fully competitive power markets.

Model Description and Structural Assumptions

Demands and Load Shapes

Electricity demand information is drawn from the NEMS demand modules by customer class and end-use or industrial type (for example, commercial lighting or paper industry electricity use) at the census division level. Each of these end-uses or industries is assigned a distinct load shape. For weather sensitive demands, the load shapes vary by region as well. In each future year, the end-use load shapes are added together and then the loads are allocated to individual power control area's (PCA's) based on the historical proportion of sales (i.e., load) within each PCA in each census division.

A unique aspect of the POEMS model is the representation of the load duration curves with vertical, rather than horizontal, time blocks. This approach ensures that trades among regions are fulfilling the same requirements, and that power generated at one time (such as at night hours) is not being used to satisfy power needed at another (such as during peak daytime hours). For the typical model applications, loads are represented by 2 segments within 6 hourly time groupings within each of 6 seasons, for a total of 72 load slices. However, these load slices can be varied by the user. Except for one peak segment, each segmnt within each season represents the average load in that time block.

Dispatch and Trade

TRADELEC™ is a network model of electricity dispatch, trade, capacity expansion and pricing as previously shown in Figure 2. The POEMS version of the model operates at the level of the power control area (PCA), representing approximately 114 regions. Figure 3 provides a map of these 114 PCAs. PCAs are represented as a series of nodes, connected by transmission interties whose capacities are specified based on transfer capabilities reported to FERC. There are almost 700 transmission links in POEMS. New transmission additions are limited to maintenance and those associated with the construction of new generating assets. Supply resources within each PCA, consisting of utility plants, exempt wholesale generators, traditional and non-traditional cogenerators, and firm power contracts, are represented in considerable detail. Existing firm power wholesale contracts for generation or capacity are typically assumed to remain in place, but a user option is available for canceling the existing contracts. Plant characteristics, such as capacity, heat rate, and forced and maintenance outage rates, are represented based on data in EIA filings and NERC Generating Availability Data System (GADS) data. TRADELEC™ incorporates financial, operational, and physical data representing virtually every significant operating electric utility in the USA and the transmission interties among them.

Plant Groupings and Dispatch

The plant input file to the model consists of virtually all units in existence in the U.S. in the most recent historical year. Each unit in the plant input file is combined with like units to form dispatchable groups. The process of combining units is flexible, but at a minimum, combined units serve the same demand region and are physically located in the same supply region, use the same fuels with the same type of prime mover and have the same in-service period. Dispatchable capacity groups also have similar heat rates and renewable groups have similar utilization patterns. Currently, there are over 6,000 plant groupings used in the model. There are 55 dispatchable plant groupings per PCA on average, with larger PCAs having as many as 350 plant groups. A merit order dispatch algorithm is initially employed to determine generation in each time segment prior to trade.

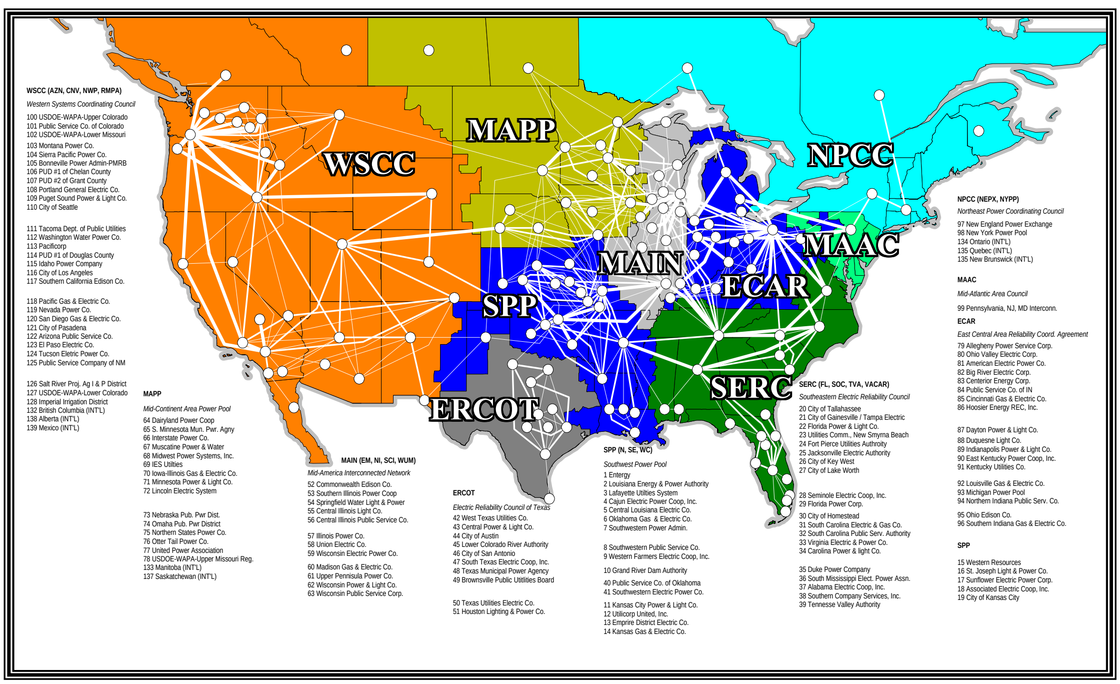
Trade

Network interregional trade is solved to maximize the economic gains from trade by ordering the trades in descending order starting with the trade that contributes the largest efficiency gains first. Succeeding trades continue until available transmission opportunities or all the possible gains are exhausted. The primary economic and physical limits to trade are imposed via alternative scenarios of transmission fees, losses, transmission capacity, and hurdle rates. Thus, integrated interregional trade is modeled to operate in much the same fashion as a full fledged, time-block power auction would operate.

Transmission Costs and Capacity

Transmission capacity is measured on a first contingency basis consistent with the established NERC rules. Transmission charges are calculated on approximations of straight-line, simultaneously available paths to project the volume and costs of electricity trade. Transmission costs are reflected through representation of transmission tariffs which can be implemented on a PCA or regional level and transmission losses which are modeled as a non-linear, distance sensitive measure. In addition, a user specified "hurdle level" is input to limit transactions to those that provide a specified minimum level economic gain. The hurdle rate can be adjusted to reflect reductions in potential inefficiencies and transactions costs as markets provide greater incentives to exploit profitable trades. The market simulation is conducted within each of the 72 time and season load slices that are modeled and the chronological simultaneity is maintained.

Figure 3: Illustrative TRADELEC™ Regional Detail



Capacity Planning

New Capacity Additions and Technology Selection

In addition to dispatching existing capacity and trading among regions, new capacity additions are forecasted by the model. The new capacity planning methodology is very similar to that of the NEMS electricity sector. The construction of all new facilities is profit motivated based on anticipated demand growth and competitive cost conditions caused by capacity shortages. Because of the higher risk associated with an unregulated market, the cost of capital is assumed to be higher than historical values for the industry. In a cost-of-service case, all new capacity is assumed to be constructed by Exempt Wholesale Generators (EWGs) which sell under long-term contracts to utilities. New capacity planning occurs at the NERC regional level, and new plants are allocated to individual PCAs based on their relative prices, system loads, and shortfall of capacity (if any).

The choice of new technology selection for new capacity is the same as in the NEMS electricity sector. The expansion algorithm minimizes the expected cost of meeting anticipated future load. In order to reflect that there will be site specific differences in costs within a planning region, the model includes a logit-based sharing mechanism. In this way technologies that are slightly more expensive will receive some market share. The TRADELEC™ capacity planning module also includes a feature that allows goals for renewable builds to be specified exogenously.

Explicit Treatment of Economic Retirements

POEMS has an explicit treatment of economic retirements. Retirements of existing capacity occur when plant operating costs cannot be recovered through market-based prices. The economic retirement decision for all generating plants is based on both short-term and long-term criteria. The short-term requirement is that plants can cover their "going-forward" costs, which include all O&M costs and annual capital additions, by the revenue they receive through the marginal cost (MCP) in the wholesale market. If a plant cannot cover these costs, it becomes a candidate for early retirement. The second consideration is the cost of building new generating capacity. In the capacity planning module, all existing units must pay their going-forward costs if the capacity is to be used over the full planning horizon. Thus the planning module has the opportunity to economically retire any or all of the existing units and instead build new capacity. If the planning module does decide to economically retire a unit and this same unit did not cover its variable costs in the last forecast year, it is retired. A plant must be uneconomic in both the short-term and long-term to be retired.

Nuclear power plants are treated somewhat differently in that they are assumed to require a major capital expenditure after 30 years of operation. In addition they have the opportunity to make an investment at the end of their 40 year licenses to life extend the plant for another 20 years. This methodology was adopted from the NEMS AEO99 version of the model.

Pricing

TRADELEC™ can represent either cost-of-service or competitive pricing[2] in retail markets. The cost-of-service pricing reflects financial information aggregated from filings made by investor-owned, public, federal, and cooperatively-owned utilities.[3] Competitive rates are based on unbundled time-specific generation prices, and transmission and distribution prices. These latter are assumed to remain cost-of-service or can be set to reflect Performance Based Ratemaking, where an incentive is included to reduce costs.

The competitive generation price is composed of the marginal cost, ancillary charges, a renewable portfolio standard (RPS) premium if applicable, and stranded costs. The stranded costs consist of decommissioning costs, regulatory assets, and generating assets. The marginal generation price in each power control area (PCA) is established through a second price auction. The price in each of 72 time and season load slices equals the marginal cost or bid price of the next least expensive option in the merit order above the last unit selected to operate. This next marginal unit could be native to the PCA or determined through trade with other PCA's. The competitive bid price for each unit is assumed to be its marginal cost in accord with the standard characterization of perfectly competitive markets. The marginal costs are the sum of the fuel costs and the variable portion of operating and maintenance (O&M) costs. The consumer's average price for generation is dependent on the load shape of demand. For example, industrial prices will be the lowest because their demands are relatively constant and a smaller proportion of their purchases will be at peak, as compared to residential and commercial customers.

Fixed and Variable O&M Costs

The historical distinction between fixed and variable O&M costs is quite arbitrary. For this reason the POEMS initially puts all O&M costs into a fixed O&M account and allows the user to determine how much of the fixed costs should be considered variable. In addition, historical levels of O&M costs are expected to be reduced over time due to the pressures of competition. The POEMS includes a feature that allows the user to specify O&M cost targets by plant type along with a specification of a percentage progress towards that target by plant type and year. Competitive pressures are also expected to spill over into the regulated segment of the industry. The POEMS also allows the user to specify transmission and distribution productivity improvements. Competition is also expected to result in heat rate improvements, which affect the generation price. POEMS includes a feature that allows the user to specify target heat rates by plant type along with a specification of a percentage improvement towards that target by plant type and year.

[2] While TRADELEC™ can estimate competitive prices under alternative approaches, the competitive pricing approach used in POEMS is implemented as a second-price auction.
[3] The information is drawn from federal filings including FERC Form 1, EIA Form 412 and RUS Forms 7 and 12.

Ancillary Charges for System Reliability

In competitive scenarios, it is assumed that ancillary charges are paid by Independent System Operators (ISOs) to generators in order to maintain the system reliability. The total expenditures are determined by the amount of revenue that owners of new peaking capacity need in addition to the market bid price in order to cover all their costs, including their fixed costs. Because of reserve margin requirements, some plants will be constructed that will not operate very much, if at all, but are needed for reliability. This additional revenue is then paid on a dollar per kilowatt-year basis to all combustion turbines and combined cycle plants in the region. Because the markets are competitive, the ISO's must pay all units the same amount and cannot discriminate between new and existing plants. The combustion turbines and combined cycle plants are the only ones that receive the payment because they can most readily be called on for quick startup reserve purposes.

Renewable Portfolio Standard

The POEMS handles the renewable portfolio standard (RPS) as a feature that can be imposed on a competitive scenario as a minimum share of generation that must be met by non-hydro renewable resources. In addition the user can impose a price cap based on a premium above the market price. The renewable resources that are eligible can be specified by the user, but generally include wind, biomass (including co-firing at coal-fired plants), solar thermal, solar PV, geothermal, and a portion of municipal solid waste. Through the NEMS renewable module, the supply of these resources are represented in considerable detail. POEMS also incorporates the ability to represent various renewable tax or production credits.

The RPS is treated as a national goal, because the renewable credits can be traded among distributors and generators. Assuming the effect of a nationwide auction, the most expensive unit needed is the one that sets the price, unless a price cap is applicable and constraining. In this case the marginal price includes capital cost recovery and is net of the market price received. Thus, the total cost of the RPS equals the maximum of the marginal renewable cost premium on a dollar per kilowatt-hour basis or the cap times the total renewable generation in each year. It is assumed that this cost is charged equally to all customers in all regions of the country.

Stranded Assets and Costs

A distinguishing feature of the POEMS model is its flexible internal treatment of stranded costs in its pricing through the transition period. Stranded generation assets are those that have remaining capital costs that cannot be recovered through competitive prices. Unlike many models, in POEMS the stranded costs are computed at the company level, where each company's assets with below market costs offset those that are above market. In the POEMS Competitive case, recovery of these costs is set by the user by specifying the percentage of recovery, the recovery period, the discount rate, and the start year of recovery. In addition, the user also sets the allocation method for recovery by customer class.

Environmental Emissions

The environmental consequences of electric restructuring are of interest to policy makers. Many factors are expected to have an impact on emissions, including increased trading, shifts in the mix of capacity additions and retirements, improvements in operating efficiencies, and changes in electricity demands. In addition, current regulatory policy for sulfur dioxide (SO_2) and nitrogen oxide (NO_x) control will influence costs and may affect plant dispatch.

The Clean Air Act Amendments (CAAA) of 1990 established a cap for SO_2 emission from non-grandfathered electric generators. Options for compliance include retrofitting units with flue gas desulfurization (FGD) equipment, switching to lower sulfur fuels, reducing utilization of high SO_2 emitters or trading emission allowances. The SO_2 cap is represented in POEMS, and the model selects the least costly way of achieving it.

The CAAA also restricts NO_x emissions from generators in two phases. In POEMS each plant is assumed to meet its Phase I or Phase II target by choosing the lowest cost technology or combination of technologies required to meet its target. The technology options include combustion controls, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). The combustion controls were selected by plant type from choices of coal reburning, low NO_x burners with and without overfire air, and low NO_x coal-and-air nozzles.

The model also incorporates the September 1998 final rulemaking establishing caps on ozone season emissions of NO_x in 22 Eastern States and the District of Columbia assuming that trading among sources is permitted. The emissions cap is added as a constraint to the linear programming (LP) capacity expansion module. An emissions reduction "supply" curve is constructed by ranking each unit's control options (combustion controls, SNCR, SCR or a combination of combustion and post-combustion controls) by cost per ton reduced. The use of the supply curve allows the consideration of the control costs of individual units without increasing the LP to an unmanageable size. The LP then chooses the level of emissions reductions and generation by fuel that meets the NO_x cap, other constraints such as the SO_2 cap, and demand requirements at the lowest cost. The lowest cost solution may include the retirement of plants as well.

There is also an option to require each unit to meet a specific emissions target without the opportunity for trade. Similar to the CAAA implementation, the lowest cost technology to meet the required rate is selected. If the cost is sufficiently high, the plant will retire instead.

The POEMS model tracks carbon emissions from all sources of the economy. The user can specify carbon taxes or permit prices which increase the price of fuels according to their carbon content.

POEMS Assumptions

By its structure and its use for policy analysis, POEMS contains either implicitly or explicitly many assumptions of how a competitive market for electricity will evolve. The most fundamental assumption is that all activities will be economically motivated and be driven by profit maximizing or cost minimizing behavior. In addition to the structural assumptions, there are several parameters that can be specified by the user in order to represent alternative scenarios of restructuring. The following provides an overview of both the structural and scenario-type assumptions in POEMS.

Basic Structural Assumptions

The structure of POEMS incorporates a variety of basic features and/or assumptions which include the following:

- Initial generation, transmission and distribution financial characterization of assets reflect the best available data.
- Regional representation includes 114 power control areas (PCAs) and 680 transmission links.
- New transmission additions are limited to maintenance and those associated with the construction of new generating units.
- Power dispatch and trading occurs for 2 segments within 6 hourly time groupings in each of 6 seasons of the year for a total of 72 load slices.
- Transmission and distribution continue to be regulated services, but can be incentive driven.
- Demand levels and load shapes are dynamic modifications of the historical record.
- Existing legislation remains in place, for example, the Clean Air Act Amendments of 1990.
- Macroeconomic and fuel price forecasts are consistent with EIA's Annual Energy Outlook (AEO).

Competitive Scenario Assumptions

A variety of assumptions are made for the competitive scenario that include the following:

- All activities are economically motivated meaning that they are driven by profit maximizing or cost minimizing behavior.
- All generation, transmission & distribution activities are unbundled.
- Electricity prices are based on the value of power plus transmission, trading and distribution costs.
- Generators have no market power.
- All consumers have direct market access and full contemporaneous information.
- Transmission charges are calculated by applying a FERC Order 888 type formula.

- Inter-regional trading clears markets in each time block, constrained by limited transmission capacity.
- New generating capacity additions and capacity retirements are profit motivated.
- No new generation capacity is rate-based.

User-Specified Scenario Options

A variety of assumptions are available for user specification in various scenarios and include the following:

- Consumer price approach:
  - PCA-level average embedded cost or market-area value priced approaches can be used.
  - Continuation of historical cross class price subsidies or same time-specific generation price to all classes of customers can be used.
  - Transmission and distribution pricing can be cost-of-service or incentive driven.
- Existing long-term wholesale contracts for generation or capacity are usually assumed unabrogated, but can be canceled.
- Competitive rates can be phased-in both over time and geographically.
- Alternative competitive transition charges (CTC) can be user specified for stranded cost recovery.
- Alternative formulas can be implemented for transmission charges.
- Renewable portfolio standard option can be imposed with or without a price cap.
- Additional optional settings include but are not limited to changing the fraction of non-fuel operating costs that are considered to be variable; increasing the risk premium on interest rates; imposing a competitive transaction hurdle charge on trades; and reducing O&M costs and heat rates to represent heightened competitive pressures.

Model Inputs and Data Assumptions

TRADELEC™ inputs include some that are completely exogenous to the model, and some that are passed from other NEMS modules. Data passed from other NEMS modules include sectoral electricity demands, fuel prices, and macroeconomic data. POEMS is currently using the NEMS modules used to produce the Annual Energy Outlook 1999 (AEO99). Exogenous inputs include such things as: power plant capacity data, technology costs and performance data, transmission capacity, electric power import assumptions, and financial assumptions. The following sections describe the sources of these input data and provide a sample of the initial settings for the POEMS.

Demand and Macroeconomic

The sectoral demand forecasts are derived from the NEMS demand modules, and POEMS currently uses the AEO99 versions. In a POEMS model run the inputs seen by the demand modules (such as electricity price) will typically be different that those in the AEO99. Therefore, the forecasted end-use demands will not be the same as those published by the EIA.

System load shapes are derived from FERC Form 714/715 filings for each PCA. Companies within each PCA have been defined by OnLocation largely based on FERC filings.

AEO99 Mid-Case Demand Sales Forecasts (billion kWh)

	1996	2000	2005	2010	2015
Residential	1,082	1,175	1,262	1,341	1,446
Commercial	9,1	1,081	1,162	1,247	1,332
Industrial	1,030	1,059	1,130	1,211	1,280
Transportation	17	18	31	44	55
Total	3,111	3,333	3,585	3,843	4,113

The macroeconomic forecasts are derived from the NEMS macroeconomic module. The EIA AEO99 mid-case assumes 2.5% growth in GDP between 1996 to 2010.

AEO99 Mid-Case Macroeconomic GDP Forecasts (billion 1992 dollars)

	1996	2000	2005	2010	2015
Gross Domestic Product	6,995	7,830	8,769	9,896	10,800

Supply and Non-Electric Conversion

Fuel prices are forecasted by the NEMS fuel supply modules and the refinery modules. Because these modules are incorporated endogenously within POEMS, the forecasted fuel prices will vary by scenario and will not be the same as those published by the EIA.

AEO99 Mid-Case Resource Fuel Prices (1997 dollars per unit)

	1996	2000	2005	2010	2015
World Oil Price (dollars per barrel)	21.01	13.97	19.25	21.30	21.91
Gas Wellhead Price (dollars per Mcf)	2.28	2.10	2.35	2.52	2.62
Coal Minemouth Price (dollars per ton)	18.85	16.59	14.93	14.00	13.21

AEO99 Mid-Case Delivered Fuel Prices to Electric Generators
(1997 dollars per million Btu)

	1996	2000	2005	2010	2015
Distillate Oil	4.96	3.83	4.81	5.11	5.28
Residual Oil	3.16	2.19	2.97	3.52	3.63
Natural Gas	2.70	2.62	2.94	3.08	3.17
Steam Coal	1.31	1.19	1.14	1.06	0.99

Electricity Generation

Generation Capacity Assumptions

Production capacity assumptions regarding utility plants, exempt wholesale generators, and nontraditional cogenerators are derived from EIA and FERC filings (Form EIA-860, Form EIA-867, Form EIA-759, and Form EIA-767). The input assumptions include 1995 capacity and announced retirements and additions. Projected capacity will reflect these inputs, as well as endogenously determined additions and economic retirements.

Existing and Exogenously Planned Capacity (GW)

	1996	2000	2005	2010	2015
Winter	750	757	773	765	739
Summer	737	744	758	750	724

Cumulative Planned Capacity by Technology (MW)

	2000	2005	2010	2015
Coal	800	1,420	1,420	1,420
Oil/Gas Steam	77	77	77	77
Combustion Turbine	5,993	17,831	17,831	17,831
Combined Cycle	2,224	5,553	5,553	5,553
Fuel Cell	2	2	2	2
Biomass	127	336	403	403
MSW	86	114	134	134
Geothermal	57	159	167	168
Hydroelectric	2,282	2,284	2,284	2,284
Wind	935	1,368	1,518	1,518
Solar Thermal	15	55	55	55
Solar PV	25	73	126	127

Existing firm purchase power contracts are derived from EIA Form 411 filings. These include existing wholesale contracts between utilities.

Firm Power Contracts (GW)

	1996	2000	2005	2010	2015
Winter	10.5	9.8	7.0	4.3	2.2
Summer	15.1	13.7	9.3	5.8	2.9

New traditional cogeneration is forecast in the industrial and commercial demand modules. In the industrial sector cogeneration is based upon the industrial steam demand and other assumptions. While the POEMS will produce a slightly different result when run with the demand modules, the table below shows the AEO99 mid-case total cogeneration and the generation that is sold to utilities.

Total Cogeneration (GW)

	1996	2000	2005	2010	2015
Cogeneration	50.5	54.6	55.4	56.8	58.3
Sales to Utilities (BkWh)	183	178	179	180	182

Transmission Capacity Assumptions

Transmission capacity is measured on a first contingency basis for each PCA from FERC 714 filings. Transmission capacity available for export from (and import into) each PCA is constrained to the PCA's maximum transmission path, and subject to line losses, transmission fees, and hurdle rates.

Because it does not make sense to sum up transmission capacity across PCAs, a national summary is not provided here.

Technology Costs and Performance Assumptions

Technology cost and performance data for new plants is derived largely from EIA's AEO99 mid-case and NERC GADS data. The following table provides a brief summary of initial plant cost and performance settings. Capital costs are adjusted in the model using NEMS assumptions about uncertainty as reflected in technological optimism and learning factors. In addition, there are user options in POEMS which allow adjustments by technology and over time to O&M costs and heat rates of existing plants.

Technology Costs and Performance Assumptions

	Capital Costs[1] (5th of a Kind) ($1997/kW)	O&M Costs ($1997/kW)	Heat Rates (Nth of a kind) (Btu/kWh)	Availability
Pulverized Coal	1,093	16.1	9,087	0.85
Advanced Coal	1,091	16.1	6,968	0.85
Oil/Gas Steam	1,004	8.1	9,500	0.85
Combined cycle – Conventional	445	5.4	7,000	0.91
Combined cycle – Advanced	405	5.4	6,350	0.91
Combustion Turbine – Conventional	329	2.7	10,600	0.92
Combustion Turbine – Advanced	325	2.7	8,000	0.92
Fuel Cell	1,458	5.4	5,361	0.87
Nuclear	1,570	55.7	10,400	plant specific
Biomass	1,448	67.2	8,911	0.80
Geothermal[2]	1,831	97.0	N/A	0.87
Municipal Solid Waste	5,892	0.0	16,000	0.78
Solar Thermal	2,120	46.6	N/A	0.27 - 0.42
Solar Photovoltaic	3,227	9.8	N/A	0.21 - 0.33
Wind	725	25.9	N/A	0.26 - 0.40

[1]Overnight capital cost plus project contingencies, excluding regional multipliers.
[2]Because geothermal cost and performance parameters are specific for each of the 51 sites in the database, the Nth-of-a-kind captial cost and hear rate are averages for the capacity built in 2000.

Reserve Margin Assumptions

The need for reserve margins is related to the availability of each power control area's generation resources and the ability to trade with others. Over the last decade, plants have become more reliable in part due to the pressures of the wholesale competition. Both forced and scheduled outages have been reduced. Trading has also increased, especially after FERC Order 888 required transmission access. In addition there has been a growing use of interruptible load contracts, which have been factored into reserve margins. In order to reflect these continuing changes, POEMS uses a reserve margin of 8% for all regions of the country except Florida, where it uses a 4% reserve margin.

Financial Assumptions

Cost of service pricing is based on 1995 FERC Form 1, EIA Form-412, and REA Forms 7 and 12 filings.

The model structure is designed to work with a variety of different discount rates and costs-of-capital to represent various scenarios.

Discount Rate/Cost of Capital For the Reference Scenario

Utility cost of capital and capital structure. This applies to both the annual revenue requirement calculations (for all segments, consisting of the generation, transmission and distribution functional segments) and to the expansion planning decision regarding the discount rate applied to calculate the present value of meeting the demand.

EWG cost of capital and capital structure. This applies to the annualized costs associated with each generation technology's investment requirement and the resultant annuity added to the fixed O&M costs in the "purchased" power portion of the revenue requirements associated with new builds. All new, unplanned builds are assumed to be Exempt Wholesale Generators (EWGs).

Discount Rate/Cost of Capital For the Competitive Scenario

Utility cost of capital and capital structure. This applies to the annual revenue requirement calculations for the transmission and distribution functional segments only.

EWG cost of capital and capital structure. This is applied the same as in the reference case, except the assumed values are raised to reflect the greater risks assumed in the competitive environment. This is also used in the expansion planning decision.

Discount Rate and Cost of Capital Assumptions

Reference Case		Utility	EWG
	Debt Fraction	0.49 - .66[1]	0.65
	Return on Debt	0.10	0.08
	Return on Equity	0.10 - 0.14[2]	0.16
Competitive Case			
	Debt Fraction	0.49 - .66[1]	0.60
	Return on Debt	0.10	0.08
	Return on Equity	0.10 - 0.14[2]	0.18

[1] Utility Debt Fraction varies by region.
[2] Utility Return on Equity is a function of the national yield on new AA bonds and some additional basis points, and varies by year.

Transmission charges

Wheeling charges are set to a percentage of the average FERC Order #888 stage one pro forma point-to-point tariff. These are generally in the range of 50 to 80 percent. A summary of wheeling fees by region is provided in Appendix A.

Appendix A: Regional Model Inputs

Annual Peaks in 1995

	Region Name	Peak (mw)
1	ECAR	83,375
2	ERCOT	43,132
3	MAAC	45,949
4	MAIN	42,175
5	MAPP	25,096
6	NEPX	19,284
7	NYPP	26,656
8	FL	28,335
9	SERC	100,574
10	SPP/N	13,295
11	SPP/SE	23,191
12	SPP/WC	17,338
13	WSCC/AZN	11,947
14	WSCC/CNV	44,496
15	WSCC/NWP	35,980
16	WSCC/RMPA	6,226

Winter Planned and Existing Capacity (Mw)

Region Name	1996	2000	2005	2010	2015
ECAR	108,476	111,763	113,458	112,588	111,568
ERCOT	56,507	57,499	57,433	56,778	56,418
MAAC	59,716	60,716	63,132	62,495	58,666
MAIN	50,952	49,517	53,636	52,345	49,014
MAPP	34,713	35,092	35,130	34,548	31,684
NEPX	27,215	25,044	25,499	25,499	23,434
NYPP	33,750	33,692	33,692	32,597	29,826
FL	36,785	37,528	37,916	36,734	35,096
SERC	129,078	131,717	135,644	134,724	127,400
SPP/N	17,144	18,155	18,907	18,870	18,833
SPP/SE	31,946	32,092	32,203	32,203	31,123
SPP/WC	24,463	24,701	26,338	26,338	26,322
WSCC/AZN	19,943	20,320	20,610	20,610	20,610
WSCC/CNV	57,722	58,223	57,839	57,624	57,386
WSCC/NWP	51,642	51,636	51,636	51,636	51,636
WSCC/RMPA	9,449	9,524	9,524	9,524	9,524
Total U.S.	749,502	757,219	772,598	765,113	738,540

Summer Planned and Existing Capacity (Mw)

Region Name	1996	2000	2005	2010	2015
ECAR	106,588	109,724	111,170	110,318	109,318
ERCOT	56,313	57,276	57,197	56,542	56,182
MAAC	57,372	58,258	60,347	59,728	55,979
MAIN	50,006	48,552	52,220	50,955	47,684
MAPP	33,764	34,131	34,169	33,595	30,786
NEPX	26,561	24,435	24,890	24,890	22,853
NYPP	32,590	32,533	32,533	31,446	28,715
FL	35,358	36,072	36,429	35,314	33,720
SERC	127,025	129,297	132,756	131,870	124,546
SPP/N	16,924	17,818	18,481	18,444	18,407
SPP/SE	31,940	32,086	32,182	32,182	31,102
SPP/WC	24,316	24,554	26,089	26,089	26,073
WSCC/AZN	19,759	20,136	20,388	20,388	20,388
WSCC/CNV	57,449	57,938	57,555	57,340	57,102
WSCC/NWP	51,716	51,711	51,711	51,711	51,711
WSCC/RMPA	9,333	9,407	9,407	9,407	9,407
Total U.S.	737,015	743,930	757,526	750,221	723,975

Winter Contracts (Mw)

Region Name	1996	2000	2005	2010	2015
ECAR	884	-12	-96	-60	-30
ERCOT	139	-9	0	0	0
MAAC	-359	-560	0	0	0
MAIN	363	154	117	73	36
MAPP	-442	-259	-283	-177	-88
NEPX	-1,125	-1,040	-408	-255	-128
NYPP	373	529	414	259	130
SERC	-936	42	219	137	69
SPP/N	-319	-121	-5	-3	-2
SPP/SE	467	168	26	16	8
SPP/WC	0	0	-5	-3	-2
WSCC/AZN	-3,450	-3,136	-2,509	-1,568	-784
WSCC/CNV	-3,113	-2,830	-2,264	-1,415	-708
WSCC/NWP	-3,287	-2,988	-2,390	-1,494	-747
WSCC/RMPA	317	288	230	144	72
Total U.S.	-10,488	-9,774	-6,954	-4,346	-2,173

Summer Contracts (Mw)

Region Name	1996	2000	2005	2010	2015
ECAR	1,409	490	150	94	47
ERCOT	156	9	0	0	0
MAAC	-334	-154	0	0	0
MAIN	400	126	280	175	88
MAPP	-1,932	-1,162	-1,010	-631	-316
NEPX	-2,045	-2,000	-405	-253	-127
NYPP	-491	-622	-178	-111	-56
SERC	-1,336	-322	-72	-45	-23
SPP/N	-278	-95	22	14	7
SPP/SE	467	168	26	16	8
SPP/WC	0	0	-64	-40	-20
WSCC/AZN	-5,366	-4,878	-3,902	-2,439	-1,220
WSCC/CNV	-5,331	-4,846	-3,877	-2,423	-1,212
WSCC/NWP	-510	-464	-371	-232	-116
WSCC/RMPA	73	66	53	33	17
Total U.S.	-15,119	-13,684	-9,347	-5,842	-2,921

Wheeling Charges (1997$/MWh)

Region Name	Dollars Per MWh
	(Discounted 50%)
ECAR	2.76
ERCOT	1.96
MAAC	2.48
MAIN	1.95
MAPP	3.23
NEPX	1.75
NYPP	3.95
FL	2.21
SERC	2.09
SPP/N	2.15
SPP/SE	2.86
SPP/WC	2.38
WSCC/AZN	4.43
WSCC/CNV	3.45
WSCC/NWP	4.41
WSCC/RMPA	2.64