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Report to Congress:

Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design: Appendixes

U.S. Department of Energy

April 30, 2003

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Contents

Page

Appendix A. Policy Office Electricity Modeling System (POEMS) and SMD Scenario Documentation . . . 1
- Overview of POEMS . . . 3
- TRADELEC™ Electricity Model . . . 4
- Model Description and Structural Assumptions . . . 6
- SMD Scenarios . . . 12
- Model Inputs . . . 16
- Scenario Outputs . . . 20
- Sensitivity Case Results - National Level . . . 25

Appendix B. GE-MAPS™ Model Description . . . 27
- Model Description . . . 29
- Base Case Data . . . 32
- GE-MAPS Studies . . . 33
- Analysis of Existing Data on Changes in Heat Rate and Availability . . . 34
- Development of Hurdle Rates . . . 39

Tables

A.1. POEMS Policy Regions (Power Market Centers) . . . 7
A.2. Summary of Case Assumptions . . . 13
A.3. NERC Subregions and RTOs . . . 15

B.1. Southeast Coal Unit Capacity Factors . . . 41

Figures

A.1. Components of the TRADELEC™ Model . . . 5
A.2. NERC Subregions . . . 15

B.1. Coal Heat Rate Trends . . . 35
B.2. Oil Heat Rate Trends . . . 36
B.3. Gas Heat Rate Trends . . . 36
B.4. Coal Availability Trends . . . 37
B.5. Oil Availability Trends . . . 38
B.6. Gas Availability Trends . . . 38
B.7. 2000 Southeast Coal Capacity Time-of-Day Generation Pattern . . . 42

Appendix A

Policy Office Electricity Modeling System (POEMS) and SMD Scenario Documentation

Overview of POEMS

The Policy Office Electricity Modeling System (POEMS) is an integrated energy model of the United States with a specific focus on the electric sector. The POEMS model incorporates a detailed integrated multi-market model that uses a constrained bilateral transaction framework for electricity market analysis employing transmission fees, transmission constraints, hurdle rates, and alternative definitions of bidding behavior. The POEMS multi-energy sector implementation relies on the Energy Information Administration's National Energy Modeling System (NEMS) and its *Annual Energy Outlook 2003* assumptions and results for the non-electricity sectors. NEMS represents all the supply and demand sectors of the U.S. energy system.

In POEMS, TRADELEC™ replaces the Electricity Market Module of NEMS to add detail and enable disaggregation of electricity markets. TRADELEC™ was designed specifically for analyzing competitive electricity markets. 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 module. In POEMS, an economic capacity expansion plan to meet future demand requirements (representing a step-wise optimal expansion plan) is developed. The expansion plan incorporates the current environmental regulations of the Clean Air Act and other relevant regulations. The expansion planning explicitly addresses the retirement of uneconomical and unused generating capacity.

POEMS has been used to perform analytic studies of many energy sector issues. It was used to support DOE's analysis of the Comprehensive Electricity Competition Act proposed by the Clinton Administration. For various participants in electricity markets, POEMS has been used to assess regional markets, forecasting electricity prices, supply, and demand under alternative economic and fuel price scenarios. The model has also been used to assess the impact of alternative environmental policies on utility industry capital turnover and inter-fuel substitution. It was used also in the National Transmission Grid Study to examine the value of trade and the economic propensity for inter-regional transmission congestion.

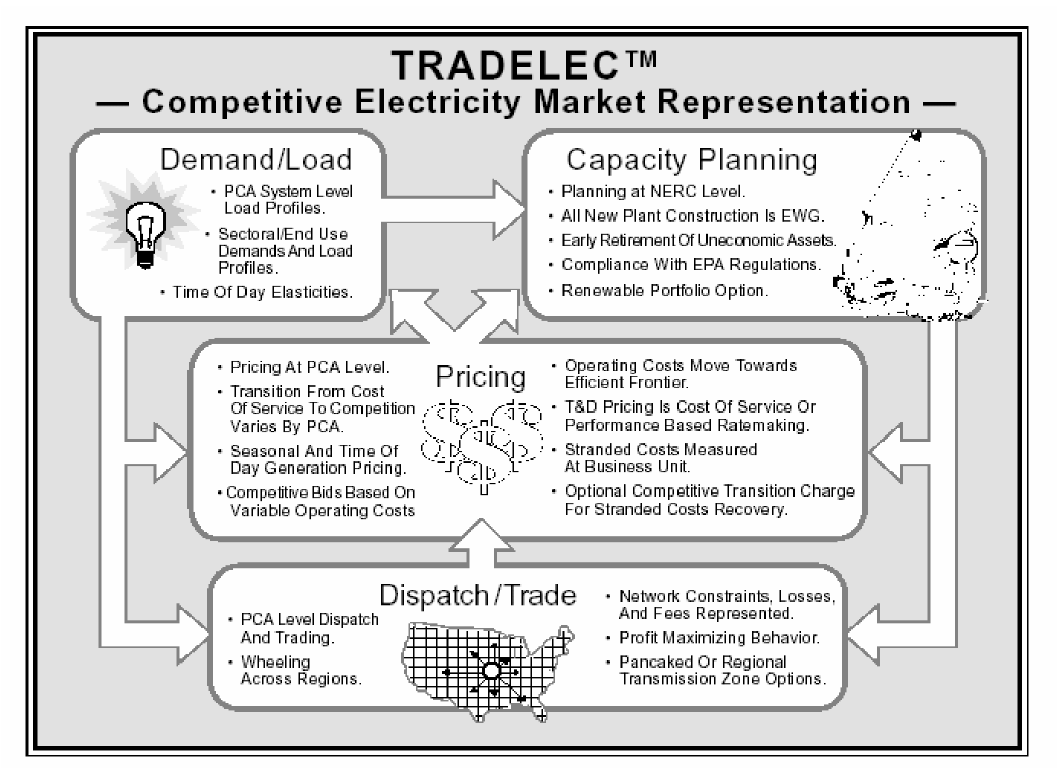
TRADELEC™ Electricity Model

The heart of the TRADELEC™ model is market-driven electricity trade over the existing electricity transmission system. Electricity trade is solved as a function of relative locational prices, transmission availability, and a hurdle rate that is designed to reflect the additional costs and inefficiencies in handling wholesale market transactions. TRADELEC™ represents transmission inter-ties at existing transfer interfaces. Current and future transmission bottlenecks may limit trade flows among certain buyers and sellers when transmission capacity is reached. This would result in final regional price differences that exceed the cost of transmission and trading.

The trading function is critical in determining competitive prices for electric power and in measuring efficiency gains from restructuring the electricity industry. By explicitly solving trade relationships, TRADELEC™ offers insights into pricing patterns and motivations for interregional trading.

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 region-specific pollution abatement measures, could further increase regional price differences even in fully competitive power markets.

Figure A.1. Components of the TRADELEC™ Model



Model Description and Structural Assumptions

Demands and Load Shapes

A unique aspect of POEMS is its 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 during night hours) is not being used to satisfy power demands at another time (such as during peak daytime hours). The definition of the time blocks is flexible. For this study, the annual load in each region is represented by total of 72 load slices: 2 segments within 6 hourly time groupings within each of six seasons.

Dispatch and Trade

TRADELEC™ is a network model of electricity dispatch, trade, capacity expansion, and pricing, as shown in Figure A.1. The model operates using POEMS' 69 regions or powercenters as described in Table A.1. These regions are combinations of the roughly 150 power control areas in the U.S. although some power pools are disaggregated to reflect transmission constraints between zones. POEMS regions are represented as a series of nodes, connected by transmission inter-ties with specific transfer capabilities. There are more than 300 transmission paths in POEMS. Supply resources within each POEMS region, consisting of utility plants, exempt wholesale generators, traditional and non-traditional cogenerators, and firm power contracts, are represented in considerable detail. Plant characteristics, such as capacity, heat rate, and forced and maintenance outage rates, are represented based on data in EIA filings and the North American Electric Reliability Council (NERC) Generating Availability

Data System (GADS) data. TRADELEC™ incorporates financial, operational, and physical data representing virtually every significant operating electric utility in the U.S. and the transmission inter-ties among them.

Table A.1. POEMS Policy Regions (Power Market Centers)

Eastern Interconnection

POEMS Regions		RTO	Regulatory Status
1	ISO-New England	ISO-NE	competitive
2	NY Central	NYISO	competitive
3	NYC	NYISO	competitive
4	Long Island	NYISO	competitive
5	NY West	NYISO	competitive
6	PJM - Central	PJM	competitive
7	PJM - East	PJM	competitive
8	PJM - Southwest	PJM	competitive
9	PJM - West	PJM	competitive
10	American Electric Power, Northern Indiana Pub Serv Co, Ohio Valley Electric Corp	PJM	competitive
11	Allegheny Power, Duquesne Light Company	PJM	cost of service
19	Virginia Electric Power, Yadkin	PJM	competitive
29	Central Illinois Light Co, Commonwealth Edison Co	PJM	competitive
12	Cinergy Corporation, Dayton Power and Light, Hoosier Energy, Indianapolis Power and Light Co, Southern Indiana Gas & Elec	MISO	cost of service
13	First Energy	MISO	competitive
14	Big Rivers Electric Corporation, LG&E Energy, East Kentucky Power Coop Inc	MISO	cost of service
15	Michigan Electric Coordinated System	MISO	competitive
30	Ameren, Columbia Water & Light, Electric Energy Inc, Illinois Power Co, Southern Illinois Power Coop, City WL&P-Springfield	MISO	cost of service
31	Madison Gas & Electric Co, Alliant East	MISO	cost of service
32	Upper Peninsula Power Co, Wisconsin Electric Power Co, Wisconsin Public Service Corp, Upper Peninsula Power Co	MISO	cost of service
33	Muscatine Power & Light, Alliant West	MISO	cost of service
34	MidAmerican Energy Company, Omaha Public Power District, St Joseph Light & Power Co	MISO	cost of service
35	Minnesota Power Co	MISO	cost of service
36	Northern States Power Co, Dairyland Power Coop, Great River Energy, Southern Minnesota Muni Power	MISO	cost of service
37	Lincoln Electric System, Nebraska Public Power District, Otter Tail Power Co, USDOE-WAPA-Upper Great Plains East	MISO	cost of service
38	Sunflower Electric Power Corp	MISO	cost of service
39	Empire District Electric Co, Independence City of, Kansas City Power & Light Co, Missouri Public Service Co, Southwestern Power Admin, West Plains, Western Resources Inc	MISO	cost of service
40	CLECO Corporation, Lafayette City of, Louisiana Energy	MISO	cost of service
41	Grand River Dam Authority, Oklahoma Gas & Electric Co, Central and Southwest, Southwestern Public Service Co, Western Farmers Elec Coop Inc	MISO	cost of service
16	Carolina Power and Light East	GridSouth	cost of service
17	Carolina Power and Light West, Duke Power Company	GridSouth	cost of service
18	South Carolina Electric and Gas, South Carolina Public Service	GridSouth	cost of service
20	Tennessee Valley Authority	TVA	cost of service
21	Southern Company Services-East, SEPA	SETrans	cost of service
22	Alabama Electric Coop, Southern Company Services-West, South Mississippi Elec Power Assn	SETrans	cost of service
23	Associated Electric Cooperative	SETrans	cost of service
24	Cajun Electric Power Corp, Entergy Electric System	SETrans	cost of service
27	Jacksonville Electric Auth	SETrans	cost of service
25	Florida Power Corp, Gainesville Regional Utilities, Reedy Creek, Florida Municipal Power Pool, Seminole Electric Coop Inc, Tallahassee City of	GridFlorida	cost of service
26	Florida Power & Light Co, Homestead, Lake Worth, New Smyrna Beach	GridFlorida	cost of service
28	Tampa Electric Co	GridFlorida	cost of service

Table A.1. POEMS Policy Regions (Power Market Centers) Continued

Western Interconnection

POEMS Regions		RTO	Regulatory Status
47	Idaho Power Co	RTO West	cost of service
48	Montana Power Co	RTO West	cost of service
49	PacifiCorp-East	RTO West	cost of service
50	Sierra Pacific Power Co	RTO West	cost of service
51	Avista Corporation	RTO West	cost of service
52	Bonneville Power Admin, PUD No 2 of Grant County, Tacoma City of	RTO West	cost of service
53	PUD No 1 of Chelan County, PUD No 1 of Douglas County	RTO West	cost of service
54	PacifiCorp-West	RTO West	cost of service
55	Portland General Electric Co	RTO West	cost of service
56	Puget Sound Energy, Inc., Seattle City of	RTO West	cost of service
65	Nevada Power Co	RTO West	cost of service
57	Public Service Co of Colorado	Translink-W	cost of service
58	Colorado Missouri/Loveland	WestConnect	cost of service
59	Arizona Public Service Co, WAPA - Lower Colorado	WestConnect	competitive
60	El Paso Electric Co	WestConnect	cost of service
61	Public Service Co of NM	WestConnect	cost of service
62	Salt River Proj Ag I & P Dist	WestConnect	competitive
63	Tucson Electric Power Co	WestConnect	competitive
64	Imperial Irrigation District	CAISO	competitive
66	Los Angeles City of	CAISO	competitive
67	CAISO - Pacific Gas & Electric Co	CAISO	competitive
68	CAISO - San Diego Gas & Electric Co	CAISO	competitive
69	CAISO - Southern California Edison Co	CAISO	competitive

Trade

Network interregional trade is solved to maximize the economic gains from trade by ordering trades in descending order, starting with the trade that contributes the largest efficiency gains first. Succeeding trades continue until available transmission opportunities or all possible gains are exhausted. The primary economic and physical limits to trade are imposed by means of alternative scenarios for 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.

Transmission Costs and Capacity

POEMS transmission path and nodal trading limits were derived from a number of sources, including the Western States Coordinating Council (WSCC) 2002 Path

Rating Catalog and various power flow cases filed with the Federal Energy Regulatory Commission (FERC) and evaluated using the Power Technologies Inc. PSS/E power-flow modeling system. In addition, updates were made to the eastern interconnection based on data from GE MAPS.

Transmission costs are reflected through representation of transmission tariffs that can be implemented on a POEMS region or Regional Transmission Organization (RTO) level. RTO definitions are flexible and can be changed for each scenario. The model uses pancaked transmission fees, in which a trade is assessed a fee for each region that it passes through, or regional postage stamp fees, where one tariff is established for each RTO that is composed of several POEMS regions. *Transmission is treated as cost of service, and any revenue collected through wholesale trade is used to offset the transmission costs borne by retail customers.* The wholesale transmission fees are normally set to a percentage (generally in the range of 50 to 80 percent) of the average FERC Order #888 stage one, pro forma, point-to-point tariff. *However for this study, they were set to values that represent a certain level of inefficiency so as to be consistent with GE MAPS.*

Transmission losses are modeled as a nonlinear, distance sensitive measure. In addition, a user-specified “hurdle level” is input to limit transactions to those that provide a specified minimum level of 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 time and season load slices that are modeled, and chronological simultaneity is maintained.

Pricing

Wholesale generation prices are established for each POEMS region for each time and season load slice. The market-clearing price equals the marginal cost or bid price of the most expensive generating unit that is operating. This next marginal unit could be native to the POEMS region or determined through trade with other POEMS regions.

The competitive bid price for each unit is assumed to be its marginal cost in accord with the standard characterization of perfectly competitive markets. Marginal costs are the sum of fuel costs and the variable portion of operating and maintenance (O&M) costs.

> *Wholesale prices* are those prices received by generators and paid by load serving entities (utilities) before being marked up for distribution losses to customers. They can be reported as annual values either by averaging each hourly price equally (time-weighted) or by taking into account different load levels (quantity-weighted). The latter is used here because it better reflects the ultimate value of the power where more is consumed on-peak than off-peak.
>
> Wholesale prices can be derived through *competitive* markets or through *split-savings* agreements. Competitively derived prices are based on the marginal cost of the last power plant needed to serve load. The plant could be native to an area or one that is supplying power from a distance in which case the cost includes the transmission charges to move it to the market in question. If there were no transmission fees, losses, or congestion, wholesale prices would be the same everywhere. In reality, of course, all of these exist, and prices will generally be lower where low-cost generators are located. The change in wholesale prices between the SMD and Non-SMD Cases shown in Table 3.3 are for these competitive wholesale prices on a load-weighted basis.
>
> Split-savings pricing is a traditional method historically used in power pools and other economy energy agreements to price transactions between utilities. The system savings achieved by the trade are split evenly between the buyer and seller. In the Non-SMD Case it is assumed that transactions between utilities are priced based on split-savings if the two are in areas without RTOs and formal markets (i.e. outside of New England, New York, PJM, or California). All purchases between utilities in which at least one belongs to an RTOs are prices competitively with the assumption that trading will occur at these transparent prices. In addition all purchases from non-utilities are priced at the competitive wholesale price. In the SMD Case, once all regions have RTOs and real-time markets, it is assumed that the competitive price will be used.
>
> The reported wholesale prices in the SMD Case include the incremental cost of RTO set-up and operations that are the costs of SMD implementation. As described in the body of the report, these costs vary by RTO.

Retail prices paid by consumers are comprised of generation, transmission, and distribution components. The distribution portion is assumed to be unaffected by the SMD proposal, so retail prices reported here are restricted to the generation and transmission components. The generation component is priced based on *cost-of-service* regulation or by *market clearing prices* in competitive regions depending on whether the area has enacted retail choice. Cost-of-service prices are built-up rates from embedded capital costs and annual fuel and operating costs. Purchase power costs and profits from exports both flow through rates to the customer. In the SMD Case, fuel cost savings associated with greater trade, shifts from split-savings to competitive wholesale prices (where applicable), changes in the competitive wholesale prices (where applicable), and the change in imports and export volumes all effect the retail generation price paid by the consumer.

For regions that have adopted competitive retail choice, market-driven wholesale prices directly determine consumer costs, adjusted for the consumer's load shape and losses incurred in delivery of electricity to the consumer. Retail customers may not literally face fluctuating time-of-day wholesale prices, but their rates must reflect the trends and conditions in wholesale markets.

In the SMD Case, the consumer prices include the SMD implementation costs previously shown in the wholesale prices.

The transmission component of retail prices is assumed to remain cost-of-service based in all regions. Retail customers pay the full revenue requirement of the native transmission system net of the revenue collected from wholesale trades. In the Non-SMD Case, with pancaked transmission fees, retail customers see reduced transmission costs when wholesale transactions associated with wheeling through or out of the area pick up some of the these costs. With the elimination of pancaking and reduced fees between RTOs in the SMD Case, in general revenues from wholesale transactions are reduced. As a result, any region that had a substantial credit from the wholesale market will likely have the retail customer paying a greater portion of the transmission revenue requirements.

Fixed and Variable O&M Costs

The historical distinction between fixed and variable O&M costs is quite arbitrary. For this reason, 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. For this study, one-half of O&M cost is assumed to be included in generator bid prices. In addition, historical levels of O&M costs are expected to decrease over time because of the pressures of competition. 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. For purposes of this study, this feature was turned off.

Competitive pressures are also expected to spill over into the regulated segment of the industry. POEMS 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. (See discussion below regarding the Scenario Definitions as they relate to these features of POEMS.)

SMD Scenarios

Table A.2 summarizes the assumptions in the Non-SMD and SMD cases and the three sensitivity cases. Each case can be briefly described as follows:

- Non-SMD: This case responds roughly to the status quo as of 2002.
- SMD: This case represents a future in which all components of the proposed SMD are implemented successfully.
- SMD With Expanded Transmission: This case is the same as the SMD but assumes 10 percent increase in transmission capability.
- SMD Without Increase in Transmission: This case is the same as the SMD but assumes 0 percent increase in transmission capability.
- SMD Without Efficiency Improvements: This case is the same as the SMD case but assumes no improvements in generator efficiency in new RTO areas.

Table A.2. Summary of Case Assumptions

Assumption	Non-SMD Case	SMD Case	Sensitivity Cases
RTOs	Four RTOs as of 2002: ISONE, NYISO, PJM,[a] CAISO	Four existing RTOs plus eight new RTOs: GridSouth, SETrans, GridFlorida, TVA, MISO (including SPP),[b] Translink-West, RTO West, and WestConnect	
Barriers to Wholesale Electricity Commerce	Combined hurdle rates[c] and transmission fees pancaked in non-RTO regions No cost for transmission within existing RTOs	No cost for transmission within RTOs Reduced cost between RTOs	
Transmission Expansion	None	5% increase in capability in 2005, from improved operational efficiency at seams that existed in Non-SMD case	(1) SMD case with 10% increase in all limiting transmission interfaces (2) SMD case with 0% increase in transmission capability
Generator Efficiency	Higher efficiencies in RTO areas (ISOs) than in non-RTO areas	Generator efficiency improvements in new RTO areas	(3) SMD case with no generator efficiency improvements in new RTO areas

[a]Does not include Allegheny Power or the proposed new additions to PJM (transmission facilities from Dominion Resources, American Electric Power, Dayton Power & Light, and Commonwealth Edison).
[b]SPP announced its decision not to join MISO after this analysis was begun.
[c]Barriers to commerce are modeled as "hurdle rates" or minimum benefits that a proposed electricity transaction must provide in order to go forward.

POEMS Scenario Assumptions

The assumptions used in POEMS were the same as those used in the GE-MAPS™ model to the extent practical, given the differences in the modeling frameworks. In the Non-SMD case, transmission fees were pancaked in all market areas that do not currently have RTOs. The transmission constraints, fees, and hurdle rates for wholesale electricity transactions were set to correspond to the same level of market inefficiency represented in the MAPS modeling.

- In the SMD cases and the sensitivity cases, all regions were assumed to have RTOs, and pancaking was eliminated.
- The generator efficiency improvements of 2 percent for coal steam and 4 percent for gas steam plants were phased in over a 5-year period, assuming that not all plant owners would achieve the improvements immediately. The least efficient plants were assumed to be improved the most, and those that are already very efficient would not be improved.

- Reserve margins were set at 15 percent for all areas except New York (18 percent) and Florida (20 percent, assumed to rely on at least 5 percent from out-of-State sources). The reserve requirements do not change between cases, and the SMD case does not attempt to measure the capital cost savings that may be associated with greater opportunities for reserve sharing under SMD.
- The model was initialized with existing capacity, augmented with all currently known and planned generating capacity under construction and expected to be on line by 2004 (consistent with the input to the MAPS modeling). This results in significant overcapacity in most regions initially. Subsequent retirement of significant oil and gas steam generating capacity is assumed to occur, followed by additional new construction as economically justified.
- The impacts on retail rates were estimated at the generation and transmission functional level. The costs of distribution functions were unchanged across all cases.
- The status of competitive retail choice varies by region and was assumed to remain unchanged in all cases.
- No additional demand response was assumed in the SMD case. (Chapter 4 of the main report, includes a separate analysis of the potential impacts of enhanced demand response under SMD.) Historical demand programs are imbedded in the underlying load data and so are incorporated in the projections.
- Demand levels were held constant between cases, so that consumer benefits could be measured without the complexity of shifting demand due to price changes.

The regional results for all cases are presented at the NERC subregion level (Figure A.2), because these are familiar boundaries in the electrical system. Table A.3 shows the relationship between the subregions and the RTOs.

Figure A.2. NERC Subregions

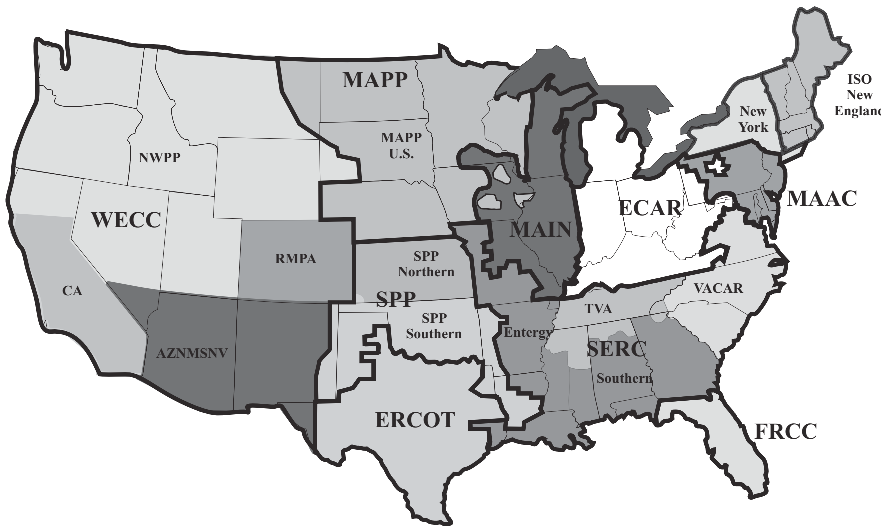


Table A.3. NERC Subregions and RTOs

NERC Subregion	SMD RTO(s)
NE	ISO New England
NY	NY ISO
MAAC.	PJM
VACAR.	PJM, GridSouth
Southern.	SeTrans
FRCC	GridFlorida, SeTrans
ECAR	PJM, MISO
TVA	TVA
MAIN	MISO, PJM
Entergy.	SeTrans
MAPP.	MISO
SPP	MISO
NWPP	RTO West
RMPA.	Translink West
AZN	WestConnect, RTO West
CA	CAISO

Model Inputs

Demand

The sectoral demand forecasts are derived from the 2003 NEMS models, with some small adjustments to reflect the GE MAPS demand levels (matched to NERC regional data); demands were lowered by about 12% in the West and were increased about 6% in the Vacar and Florida portions of SERC. 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.

Demand Sales Forecasts (billion kWh)

	2005	2010	2015	2020
Residential	1,204	1,309	1,390	1,479
Commercial	1,203	1,347	1,502	1,665
Industrial	924	1,051	1,154	1,233
Transportation	22	25	29	34
Total	3,353	3,732	4,074	4,410

Demands by Region (billion kWh)

	2005	2010	2015	2020
Total	3,353	3,732	4,074	4,410
ECAR	554	614	660	705
MAAC	260	287	307	325
MAIN	255	280	300	321
MAPP	164	182	197	211
NEPX	123	134	141	147
NYPP	156	170	177	181
FRCC/FL	212	240	268	297
VACAR	299	338	377	416
TVA	162	181	198	214
Entergy	148	166	182	196
Southern	212	238	263	288
SPP	180	199	219	236
AZN	104	118	133	149
CNV	238	264	294	326
NWP	229	255	284	313
RA	58	66	75	84

Fuel Prices

Fuel prices are forecasted by the NEMS fuel supply models and the refinery models, and are also based on *AEO2003*.

AEO-2003 Resource Fuel Prices (2002 dollars per unit)

	2005	2010	2015	2020
World Oil Price (dollars per bbl)	23.68	24.34	25.00	25.71
Gas Wellhead Price(dollars / Mcf)	2.91	2.92	3.11	3.16
Coal Minemouth Price (dollars / ton)	15.88	14.78	14.30	13.81

Delivered Fuel Prices to Electric Generators
(2002 dollars per million Btu)

	2005	2010	2015	2020
Distillate Oil	5.10	5.44	6.03	6.09
Residual Oil	3.63	3.60	3.69	3.75
Natural Gas	3.36	3.89	4.24	4.40
Steam Coal	1.13	1.10	1.08	1.04

Electricity Generation Capability

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). It also includes planned capacity from GE MAPS. The following tables exclude ERCOT in the various measures of supply capability.

Existing and Exogenously Planned Capacity (GW)

	2005	2010	2015	2020
Winter	794	781	780	776
Summer	771	758	757	753

Cumulative Planned Capacity by Technology (MW)

	2002	2003	2004	2005
Combined Cycle	29,810	71,743	82,274	85,683
Coal	715	795	1,315	1,583
Combustion Turbine	21,485	30,040	30,534	30,744

Summer Planned and Existing Capacity (Mw)

Region	2005	2010	2015	2020
ECAR	124,622	124,474	124,474	124,474
MAAC	59,402	56,086	57,220	56,086
MAIN	54,342	51,952	51,952	50,552
MAPP	31,471	31,442	31,442	31,442
NE	34,287	34,287	34,287	34,287
NY	36,884	37,571	36,587	36,587
FRCC	39,672	38,797	38,797	38,298
VACAR	53,605	52,620	52,620	52,620
TVA	24,978	23,850	23,850	23,850
Entergy	45,640	44,660	44,416	44,416
Southern	55,904	55,701	55,095	54,366
SPP	49,690	48,305	48,252	48,124
AZN	32,032	32,032	32,032	32,032
CNV	62,264	60,114	60,114	60,114
NWP	54,828	54,804	54,804	54,804
RA	11,009	11,009	11,009	11,009
Total	770,628	757,702	756,949	753,059

Note: Ercot not included in this table, total line is a national total minus ercot.

International Imports/Exports

Existing firm purchase power contracts from Canada to the U.S. were derived from information regarding Canadian to U.S. flows from the GE MAPS.

Net Imports from Canada - Firm Contracts (Megawatts)

	2005		2010	
	Avg Min	Avg Max	Avg Min	Avg Max
New England				
Winter	192	673	96	337
Summer	375	2,020	187	1,010
New York				
Winter	304	750	152	375
Summer	611	2,125	306	1,063
MAPP				
Winter	341	0	227	0
Summer	579	0	386	0
ECAR				
Winter	0	542	0	271
Summer	0	583	0	292
NWP				
Winter	883	1,718	441	859
Summer	0	1,106	0	410

Cogeneration

New traditional cogeneration is forecast in the industrial and commercial demand models. In the industrial sector cogeneration is based upon the industrial steam demand and other assumptions.

Total Cogeneration (GW)

	2005	2010	2015	2020
Cogeneration	62.6	69.2	77.4	86.1
Sales to Utilities (BkWh)	90.8	109.0	123.4	142.6

Technology costs and performance assumptions

Technology costs and performance data for each new plant is derived largely from EIA's AEO2003 mid-case and NERCGADS 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 Characteristics and Performance Assumptions - 2005

	Capital Costs ($2002/kW)	Fixed O&M Costs ($2002/kW)	Heat Rates (Btu/kWh)	Availability
Pulverized Coal	1,156	44.4	9,253	0.87
Advanced Coal	1,370	38.8	7,469	0.87
Oil/Gas Steam	0	8.6	0	0.87
Combined cycle - Conventional	472	20.3	7,343	0.91
Combined cycle - Advanced	596	20.3	6,639	0.91
Combustion Turbine - Conventional	350	7.3	11,033	0.92
Combustion Turbine - Advanced	465	7.3	8,567	0.92
Fuel Cell	1,885	20.3	5,744	0.87
Nuclear (Advanced)	1,846	62.5	10,400	plant specific
Biomass	1,621	73.3	8,911	0.80
Geothermal	1,766	103.7	N/A	0.95
Municipal Solid Waste	1,476	100.4	13,648	0.90
Solar Thermal	2,556	49.9	N/A	0.42
Solar Photovoltaic	2,836	10.3	N/A	0.30
Wind	959	26.6	N/A	0.39

Scenario Outputs

The following series of tables provide a summary of selected outputs from the POEMS model for the cases indicated.

In order to establish the capacity additions required above those identified in the input files as current and planned, the POEMS model was run under the Non-SMD assumptions to identify the capacity needed to meet the input reserve margins. The following three tables summarize the results of this assessment. The tables provide the end of year capacity, the capacity retired by the model and the cumulative additions (mostly added by the model) by the NERC subregions. These capacity levels were then input to *all* the cases.

End of Year Capacity by Region (MW)

	2005	2010	2015	2020
Total	867,330	862,908	949,690	1,027,193
ECAR	127,960	130,873	141,130	148,233
MAAC	68,775	65,975	70,881	75,845
MAIN	65,055	66,870	71,558	74,468
MAPP	40,535	45,106	48,428	52,134
NEPX	35,724	29,295	31,003	32,356
NYPP	39,583	39,654	41,754	41,263
FRCC/FL	52,017	54,475	61,774	68,120
SERC/VACAR	65,936	67,250	76,958	87,485
SERC/TVA	39,711	41,043	45,898	51,172
SERC/ENTER	48,873	34,809	39,350	44,381
SERC/SOC	60,115	60,656	66,769	73,584
SPP	53,485	52,811	58,336	61,997
WSCC/AZN	35,805	37,529	43,944	47,592
WSCC/CNV	65,102	63,177	68,636	74,595
WSCC/NWP	56,630	59,749	66,240	75,068
WSCC/RA	12,024	13,636	17,031	18,900

Cumulative Retirements by Region (MW)

	2005	2010	2015	2020
Total	29,505	106,392	106,980	117,419
ECAR	4,592	7,728	7,728	7,728
MAAC	2,900	13,390	13,390	13,390
MAIN	449	4,813	4,813	6,213
MAPP	362	443	443	443
NEPX	1,285	8,004	8,004	8,080
NYPP	348	6,753	6,817	10,369
FRCC/FL	3,024	8,016	8,016	8,819
SERC/VACAR	5,146	8,835	8,835	8,835
SERC/TVA	2,275	3,527	3,527	3,527
SERC/ENTER	1,851	18,294	18,294	18,294
SERC/SOC	1,744	4,564	5,088	5,618
SPP	2,545	5,225	5,225	5,298
WSCC/AZN	962	4,662	4,662	4,662
WSCC/CNV	1,491	8,706	8,706	12,686
WSCC/NWP	352	2,027	2,027	2,027
WSCC/RA	179	1,405	1,405	1,430

Cumulative Additions by Region (MW)

	2005	2010	2015	2020
Total	163,299	234,995	321,067	408,895
ECAR	19,709	25,628	35,884	42,988
MAAC	12,601	20,178	25,084	29,934
MAIN	10,084	16,176	20,865	25,175
MAPP	5,150	9,802	12,954	16,660
NEPX	8,564	8,832	10,540	11,969
NYPP	3,851	10,313	12,477	15,538
FRCC/FL	15,331	22,782	30,081	37,230
SERC/VACAR	8,816	13,616	22,793	33,320
SERC/TVA	6,204	8,653	13,284	18,557
SERC/ENTER	14,926	17,272	21,667	26,699
SERC/SOC	16,417	19,777	26,184	33,530
SPP	11,549	13,555	19,081	22,815
WSCC/AZN	11,906	17,330	23,746	27,393
WSCC/CNV	12,530	17,789	23,248	33,187
WSCC/NWP	3,930	8,723	15,215	24,042
WSCC/RA	1,731	4,569	7,964	9,858

The following tables provide the data that was used to produce the graphs in the main body of the report. In each instance, the table has been annotated to identify the associated graph(s).

Generation by Fuel (Selected) Non-SMD
Billions of Kwh

	Coal			Gas			Oil		
	Near	Mid	Long	Near	Mid	Long	Near	Mid	Long
NE	21	21	27	70	76	75	5	7	6
NY	30	33	45	57	71	66	5	5	4
MAAC	149	153	166	48	61	60	2	2	2
VACAR	167	185	228	21	41	44	2	2	2
Southern	180	191	214	27	39	38	1	1	1
FRCC	77	108	152	87	96	83	18	17	15
ECAR	542	574	587	42	75	99	3	3	3
TVA	121	132	151	7	13	12	1	1	1
MAIN	166	182	192	7	19	24	1	1	1
Entergy	59	64	87	54	66	58	1	1	1
MAPP	139	151	161	6	14	19	1	1	1
SPP	145	150	173	44	54	48	1	1	1
NWPP	89	95	123	43	68	75	1	1	0
RMPA	50	72	79	11	10	10	0	0	0
AZN	78	118	133	37	32	31	0	0	0
CA	26	26	26	96	101	125	1	3	7

Generation by Fuel (Selected) SMD
Billions of Kwh

	Coal			Gas			Oil		
	Near	Mid	Long	Near	Mid	Long	Near	Mid	Long
NE	21	21	27	71	76	74	5	6	5
NY	30	33	45	55	69	65	4	4	4
MAAC	134	144	155	30	50	50	1	2	2
VACAR	167	184	228	17	38	42	1	1	1
Southern	179	190	213	22	38	39	1	1	1
FRCC	77	108	152	85	89	79	11	10	8
ECAR	560	586	592	44	84	108	3	3	3
TVA	124	131	153	8	16	17	1	1	1
MAIN	183	193	199	8	25	28	1	1	1
Entergy	59	64	87	52	65	61	1	1	1
MAPP	156	159	170	5	12	15	1	1	1
SPP	145	150	175	44	54	49	1	1	1
NWPP	89	95	123	42	68	76	0	0	0
RMPA	50	72	79	11	10	10	0	0	0
AZN	78	118	133	56	46	47	0	0	0
CA	26	26	26	78	88	110	1	2	6

Data in support of Figures 3.14 and 3.15 (differences were reported in the figures).

Supply/Demand Balance 2005

Capacity (Gigawatts)					
2005	O/G Steam	New Capacity	Other	Total	Peak Demand + Reserve Margin
NE	8	12	16	36	27
NY	12	3	24	40	37
MAAC	9	13	49	71	61
VACAR	2	11	56	69	68
Southern	2	20	40	62	51
FRCC	13	16	24	53	49
ECAR	4	23	104	131	119
TVA	0	8	34	42	37
MAIN	4	13	48	65	62
Entergy	17	18	15	50	34
MAPP	1	5	35	41	41
SPP	12	13	30	54	48
NWPP	1	4	52	57	49
RMPA	0	2	10	12	12
AZN	3	12	22	37	27
CA	20	11	36	66	63
Total	106	184	595	884	786

See Figure 3.4.

Near-Term Inter-Regional Trade
NonSMD (Billions of Kwh)

	Imports	Exports
NE	(1)	2
NY	(22)	2
MAAC	(4)	25
VACAR	(21)	0
Southern	(0)	23
FRCC	(25)	0
ECAR	(1)	20
TVA	(0)	7
MAIN	(3)	2
Entergy	(12)	2
MAPP	(1)	7
SPP	(3)	6
NWPP	(6)	27
RMPA	(5)	3
AZN	(2)	39
CA	(57)	0

See Figure 3.5.

	RTO costs	
Region	**Millions $**	**$/MWH**
NE	-	-
NY	-	-
MAAC	37	0.14
VACAR	110	0.37
Southern	60	0.28
FRCC	101	0.47
ECAR	97	0.17
TVA	40	0.24
MAIN	43	0.17
Entergy	42	0.28
MAPP	31	0.19
SPP	34	0.19
NWPP	97	0.42
RMPA	27	0.45
AZN	32	0.30
CA	12	0.05

See Figures 3.2, 3.3, 3.11 and 3.12.

	Wholesale Prices Non SMD		
Region	Near	Mid	Long
NE	37	42	42
NY	40	42	42
MAAC	35	39	39
ECAR	28	33	34
VACAR	33	38	37
TVA	29	35	33
Southern	31	37	36
Entergy	31	36	35
FRCC	40	44	43
MAIN	27	33	34
MAPP	27	36	36
SPP	32	39	38
NWP	41	42	43
RA	39	38	39
AZN	37	39	38
CA	41	45	45
Average	33	38	38

	Wholesale Prices SMD		
	Near	Mid	Long
NE	38	41	42
NY	39	42	41
MAAC	31	36	36
ECAR	29	34	34
VACAR	31	36	36
TVA	30	36	35
Southern	30	36	36
Entergy	30	35	35
FRCC	39	41	40
MAIN	30	35	35
MAPP	30	35	36
SPP	30	36	35
NWP	39	41	42
RA	38	39	40
AZN	38	39	39
CA	39	43	43
Average	33	37	37

	Retail Prices: Generation and Transmission Components Non-SMD		
	Near	Mid	Long
NE	46	51	53
NY	55	58	57
MAAC	40	45	44
ECAR	36	38	38
VACAR	42	42	43
TVA	35	35	36
Southern	44	43	44
Entergy	48	49	50
FRCC	52	55	55
MAIN	37	39	39
MAPP	43	41	41
SPP	42	43	43
NWP	38	44	45
RA	44	45	45
AZN	50	52	52
CA	50	55	56
Average	43	45	45

	Retail Prices: Generation and Transmission Components SMD		
	Near	Mid	Long
NE	46	51	52
NY	54	57	56
MAAC	37	43	42
ECAR	36	38	38
VACAR	41	42	42
TVA	35	35	36
Southern	44	44	44
Entergy	48	49	49
FRCC	53	56	55
MAIN	39	40	40
MAPP	41	40	41
SPP	41	43	42
NWP	38	44	46
RA	44	45	45
AZN	52	54	53
CA	49	54	55
Average	42	44	45

See Figures 3.6-3.9, 3.11 and 3.12.

Sensitivity Case Results – National Level

Volume of Inter-Regional Trade
Billions of Kwh

Interconnection	Non-SMD	SMD	Period
East	95	176	near
West	70	92	near
East	84	168	long
West	97	116	long

See Figure 3.13.

Fuel Cost Savings			
Billions of 2002 Dollars			
Case	Near	Mid	Long
Fuel Costs			
Non-SMD	48.2	58.4	61.8
SMD	47.1	57.3	60.9
Annual Savings	1.1	1.1	0.9

See Figure 3.16.

Electricity Savings			
Annual Averages (Millions of 2002 Dollars)			
Case	Near	Mid	Long
SMD	1,799	1,588	1,482
SMD w/o 5% T	1,797	1,588	1,490
SMD w/o GEI	1,458	915	965
SMD w/ 10% T	1,850	1,666	1,505
RTO Costs	762	762	762

See Figure 3.10 and 3.19.

Total Volume of Trade		
Billions of Kwh		
Case	Near	Long
SMD	104	102
SMD w/o 5% T	104	102
SMD w/o GEI	104	104
SMD w/ 10% T	109	106

See Figure 3.17.

Annual average change in fuel cost from base			
Millions of 2002 Dollars			
Case	Near	Mid	Long
SMD	1,095	1,092	926
SMD w/o GEI	773	591	458
SMD w/o 5% T	1,094	1,090	925
SMD w/ 10% T	1,144	1,136	959

See Figure 3.18.

Appendix B

GE-MAPS™ Model Description

Model Description

GE-MAPS™ (Multi-Area Production Simulation) simulates the electrical power system as it would be operated by control room operators. The program has evolved over the past 30-years as operational practices and concerns have changed, but always with the in a way that accurately represents operational decisions. The GE-MAPS program was modified to incorporate the detailed representation of the transmission system in the mid-1970s to address difficulties encountered by the New York Power Pool in simulating the effect of frequently encountered transmission congestion. Working closely with a number of utility systems, particularly in New York and PJM, the program has continued to be enhanced over the years. These enhancements have included providing improved representation of security constrained commitment decisions, operation of phase angle regulators, and the operation of high-voltage DC transmission lines. With almost 30 years of growth and experience behind it, the GE-MAPS model has become a standard in the industry for performing detailed economic studies of the combined generating and transmission systems. The program is currently licensed by the Independent System Operator – New England, the New York Independent System Operator, PJM Interconnection, the Midwest Independent System Operator, and the Independent Market Operator of Ontario, Canada, in addition to many other private and public firms.

GE MAPS is built around a detailed production cost simulation model that operates the system in the manner that minimizes the total cost of producing electricity. The production cost model captures the relative cost of different alternative sources of electricity generation along with the operational limits imposed by plant physical requirements. Limitations imposed by the transmission system are also thoroughly captured, allowing GE-MAPS to more accurately predict the operation of generating units and the utilization of the transmission system.

GE MAPS extracts a DC representation of the power system from a full, solved AC power flow. The power flow in the transmission system is represented This approach assures that the system representation within GE-MAPS is fully consistent with the system characteristics being used by system operators and transmission planners.

The program determines a security constrained commitment[1] that minimizes the cost of operations while still assuring that the system is operated in a manner that allows it to accommodate the specified number of contingencies.[2] Once the commitment is determined, GE-MAPS performs a sequential, hourly calculation of the least cost manner of providing the required amount of electricity, again assuring that the system remains capable of accommodating contingencies. These calculations are quite complex and require carefully monitoring the operation of every generating unit and many transmission system components.

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[1] Commitment is the decision to place a generating unit on line, or to put it into a condition where it is available for system operators to call on. For most generating units this entails operating the unit at some level of power production.

[2] A contingency is essentially an assumed failure within the power system. Successfully accommodating the contingency requires that no line or component in the system be overloaded as a result of the contingency occurring.

In the process of simulating operation of the system, GE-MAPS™ calculates hourly power production, transmission flow, and consumption throughout the entire electrical grid. These simulations allow a number of useful measurements to be made of system performance, including:

- Calculations of hour-by-hour, nodal or bus spot prices[3] of energy.
- Calculations of hourly line flows for each transmission line.
- Determination of congestion costs.[4]
- Determination of unit revenues based on MW output and bus spot prices.
- Determination of load payments based on hourly load and spot prices.
- Computation of hourly emission quantities and emission credit trading costs.
- Identification of generators responsible for power flows on individual transmission lines.

The GE-MAPS™ program derives its considerable forecasting potential from its ability to faithfully reproduce, on a fundamental basis, the actions and decisions typically undertaken during integrated system operations. The GE-MAPS™ program utilizes a fully developed nodal network for the system of interest. Forecasts of system operations are driven by specific wholesale market designs. Consequently, the program is capable of forecasting discrete wholesale prices and individual line or interface flows under a locational marginal pricing scheme or bilateral market structure.

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[3] These are the cost of providing the next incremental unit of power to that location. These prices nominally represent the energy component in the wholesale price of power.

[4] Congestion cost is the increased cost incurred as a result of needing to operate more expensive generation to assure that all transmission system line limits are respected and to assure that the system can accommodate contingencies.

The program calculates nodal energy market clearing prices based on the marginal cost of production for each hour simulated. Since the program is using bus-based demand and deriving clearing prices at this same level of granularity, determination of load-weighted zonal prices for each simulated hour or across longer time periods is straightforward. This level of detail also allows the program to derive and capture discrete line and interface flows as well as any congestion resulting from the secure operation of the system. Interface and zonal boundaries can be readily defined and modified.

Base Case Data

GE-PSEC possesses extensive generating system databases and maintains a fully developed nodal network model data set for all the regions in the Eastern Interconnection (EI) and the WECC system. The information contained in or represented by this set of four integral elements includes:

(1) *Area Loads* – Chronological hourlyload shapes, annual peak loads, and total energy requirement projections for the areas within the EI and WECC systems; loads are assigned to individual load buses as defined in the power flow representation.

(2) *Generation* – Thermal unit characteristics including multi-segment heat rates, forced and planned outage rates, fixed and variable operations and maintenance costs, minimum downtime and uptime, must run requirements, emissions rates, and fuel requirements, hydro-electric generation constraints, and operating reserve requirements.

(3) *Transmission* – System topology characteristics including summer and winter line ratings, normal/short-term emergency/long-term emergency line ratings, constraints including monitored lines and nomograms, HVDC terminals and lines, and phase angle regulators.

(4) *Solved AC Power Flow (ACPF)* – A solved ACPF for the EI and WECC systems that have been assembled from public sources and validated for use with the GE-MAPS™ program.

The existing generation data (unit type, performance characteristics-heat rate etc. and cost) is obtained from RDI Basecase and modified as appropriate using GE-PSEC in-house information and other public data sources. New (proposed) generation data is obtained from RDI NewGen and refined using GE-PSEC information. The NERC ES&D (Electricity Supply & Demand) database is used to obtain regional peak and energy load forecasts. The source of transmission data (AC powerflows) is FERC 715 filings. Power system interface definitions and limits, flowgates and other transmission system data (such as the WECC Path Rating Catalog) are obtained from other public sources.

GE-MAPS Studies

GE-PSEC has performed numerous studies for a variety of organizations and companies using GE-MAPS™. These studies have ranged from providing electricity price forecasts for virtually every region of the U.S. to asset evaluations (both generation and transmission assets) to evaluating implications of new regulations (such as environmental compliance rules) on power system and power plant performance. GE-MAPS™ was also used in studies to investigate formation of RTOs to comply with FERC Order 2000. It was used to analyze the impact of combining NYISO and ISO-NE into a single RTO (NERTO). It was also used to study the formation of an RTO in the southern U.S. (SEARUC) and its impact on the region. PJM uses GE-MAPS™ as a benchmarking tool to check the clearing spot prices obtained with its own market simulation model.

Most of the major ISOs in the U.S license and use GE-MAPSTM. Current RTO/ISO-based licensees include: New York ISO, ISO New England, PJM, Midwest ISO, and Ontario IMO. GE-MAPSTM is also licensed by federal/state entities such as NRUCFC, NYS Public Service Commission, CEC (California Energy Commission) and electric utilities such as Comision Federal de Electricidad (Mexico), APS (Arizona Power Service), SRP (Salt River Project), FPL (Florida Power & Light) and ConEd (Consolidated Edison).

Analysis of Existing Data on Changes in Heat Rate and Availability

It has been postulated that the implementation of the SMD will lead to improvements in plant efficiency (heat rate) and availability. To examine this further, heat rate data for power plants in the Northeastern U.S. (where an SMD-type environment already exists) and the rest of EI was collected from the RDI BaseCase summary of generating unit CEMS (Continuous Emission Monitoring System) reports. For Coal plants, Figure B.1 shows the change in plant full load heat rate for the years 1995 through 2001 plus as much data from 2002 as is currently available with all data indexed to the 1995 values. The data was examined back through year 1995 to determine when the heat rate improvements began. Figures B.2 and B.3 show the change in plant full load heat rate changes for Oil and Gas steam power plants respectively, for the years 1998 through 2001 plus as much data from 2002 as is currently available. All values are indexed to the average heat rates observed in 1998. Figure B.1 clearly shows no change till 1998 when the RTO formation began. It can be observed that the heat rates for Coal and Gas power plants in Northeast region have improved at a faster rate than those in other regions. Oil power plants heat rates, on the other hand, appear to have improved more outside of the Northeast.

Figure B.1. Coal Heat Rate Trends

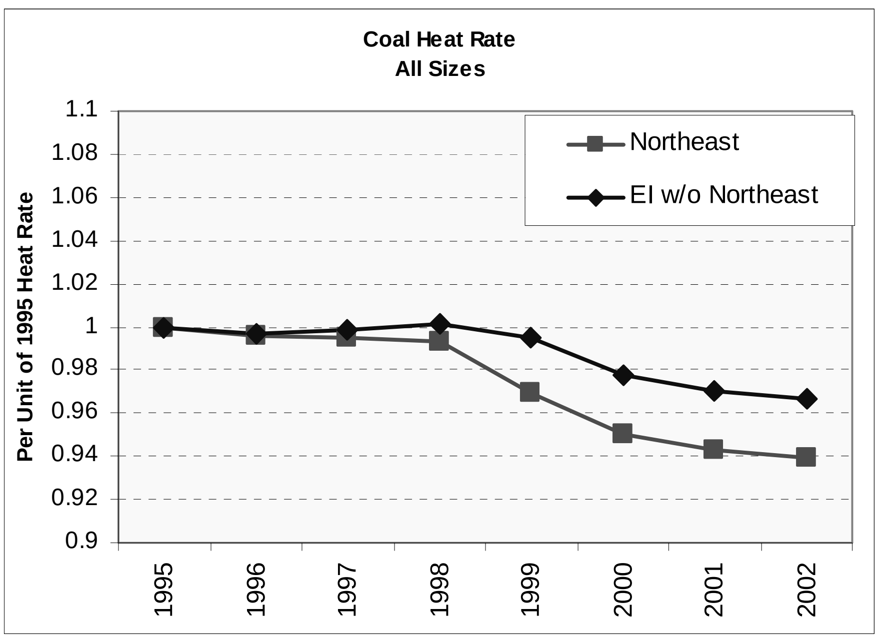


Figure B.2. Oil Heat Rate Trends

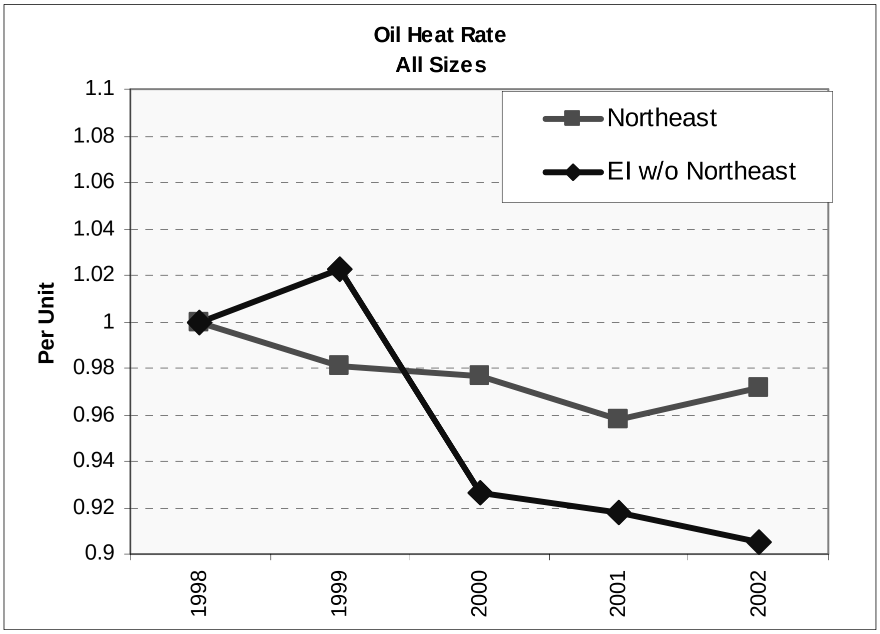
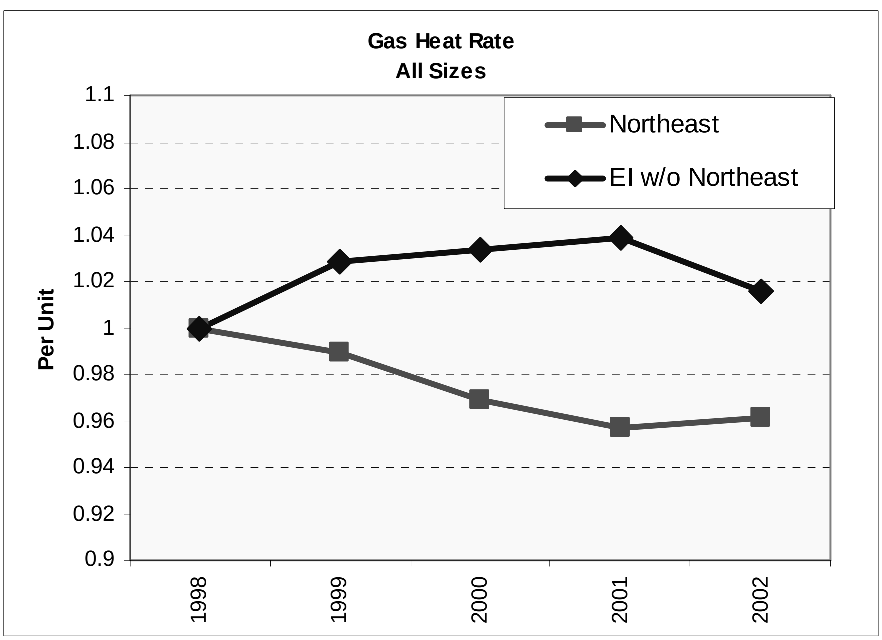


Figure B.3. Gas Heat Rate Trends



Availability of different plant types was assessed using the NERC GADS database. These data are currently only available through 2000. Figures B.4, B.5, and B.6 show the change in median plant availability rates for Coal, Oil, and Gas power plants respectively, from the year 1995. As shown in the figures, there is no clear, definite distinction in the trend in power plant availability for the Northeast relative to the rest of the Eastern Interconnect. Therefore, availability improvement as a result of SMD is not assumed.

Figure B.4. Coal Availability Trends

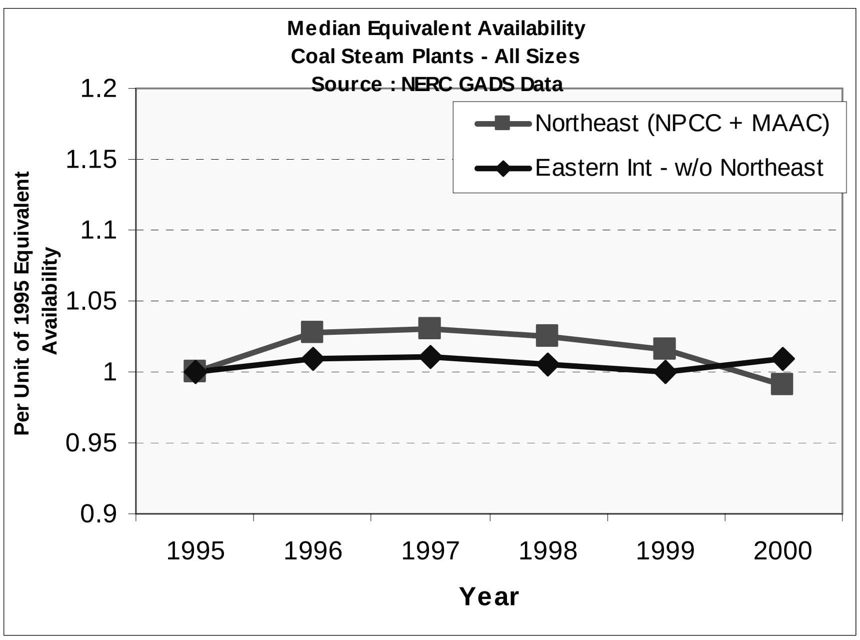


Figure B.5. Oil Availability Trends

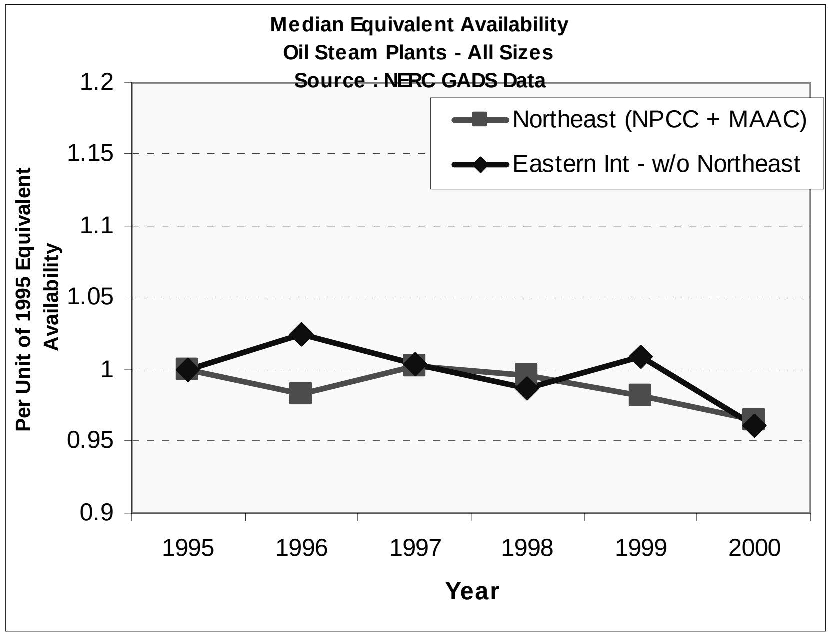
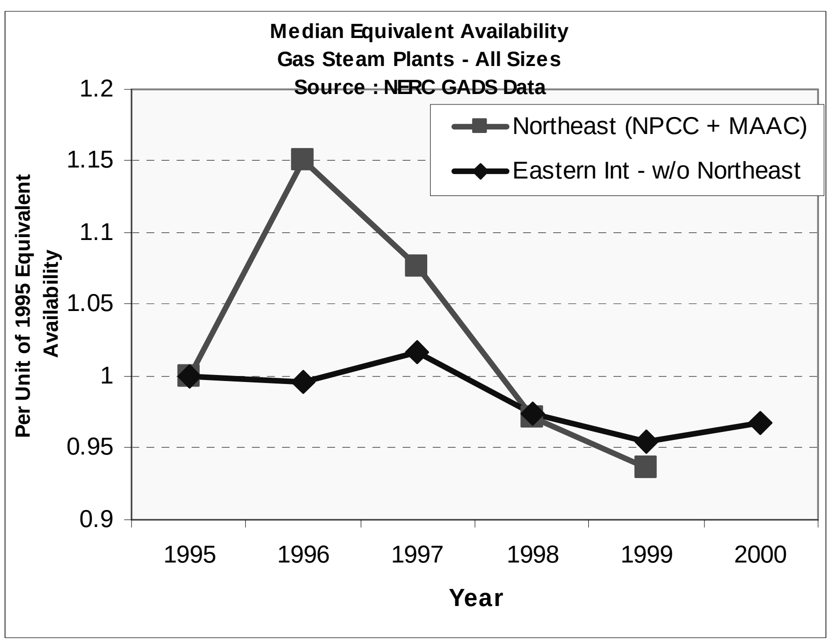


Figure B.6. Gas Availability Trends



Development of Hurdle Rates

One of the fundamental steps of this analysis was the development of the operational hurdle rates to model the economic inefficiencies in the markets. Simulation tools like MAPS and POEMS can be quite efficient in operating the system to minimize total costs, to the point of finding transactions a thousand miles away to save a nickel. Actual utility operations, balkanized into hundreds of separate control areas, are not as "all knowing" in their transactions or as precise in their operations. Many regions "self commit" their own generation to serve their loads and only then do they look to neighboring regions for purchase and/or sale opportunities which could result in significant savings. Operators may look for the easiest deal, i.e. trading with their next-door neighbor, rather than looking for the "best" deal which may come from three regions away and involve several wheeling arrangements, even though that may save an additional 10%. Often the lack of transparency of the system will make the operators unaware of these deals and the difficulty of arranging the transactions may make them infeasible in the rapidly changing real time environment.

A methodology was developed in an analysis of the Northeastern US which examined the potential benefits of various combinations of ISO New England, New York ISO and the PJM ISO.[5] A simulation was performed for the year 2000 which examined the flows taking place between the three ISOs. Once the data was adjusted to match historical loads, fuel prices and installed capacity it was

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[5] "Economic and Reliability Assessment of a Northeast NERTO," June 2002, New York ISO and ISO NEW England.

assumed that any difference between actual annual flows and model predictions were due to the economic hurdles between the ISOs. These hurdles include the actual wheeling rates between the regions, costs for losses, minimum savings thresholds, operating concerns not modeled by the program and a lack of transparency that prevented all potential trades from being determined. The total hurdle rates between the regions were then adjusted iteratively until the predicted annual energy flows between the regions matched the historical values.

There is no doubt that these various operating inefficiencies exist. The question is "How much of them can or will go away under other operating regimes?" Some costs, such as existing wheeling rates, can be reduced or eliminated. Other costs, such as losses, will always be present. But is can be assumed that much of the inefficiencies due to lack of transparency of the markets can and will be eliminated through the introduction of larger control areas and Standard Market Design.

A second analysis that contributed to the determination of the hurdle rates examined the operation of the Southeastern portion of the US.[6] This study, performed jointly by GE Power Systems Energy Consulting and Charles River Associates built upon the methodology developed in the NERTO study. However, in this case the flow information between all of the regions was not readily available. Instead we examined the operation of various generation types in the region.

[6] "The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast," November 2002, The Southeastern Association of Regulatory Utility Commissioners.

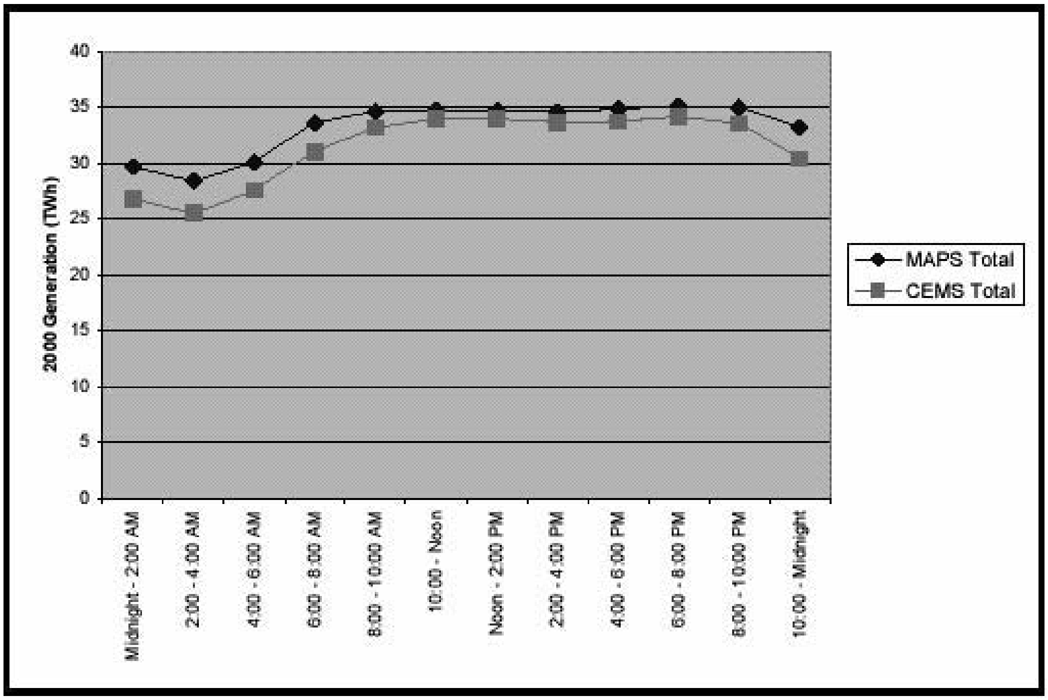
In general, if we have modeled the historical loads, fuel prices and transmission constraints correctly then an efficiently operated system would be expected to operate the far more economic coal plants in favor of the more expensive oil and gas units. Restrictions such as inter-regional wheeling rates, self commitment decisions, unrealistic regional imports and exports and lack of operating transparencies can all serve to drive the capacity factors of the coal plants down. We compared the on and off peak capacity factors of the Southeastern coal plants to the information available from the EPA's Continuous Emissions Monitoring System, CEMS. The results in Table B.1 below show the final comparison after iterating on various hurdle rates in both the southeast and the rest of the eastern interconnection.

Table B.1. Southeast Coal Unit Capacity Factors

	MAPS	CEMS
Peak Hours	74%	75%
Off-Peak Hours	66%	64%
Total	70%	70%

Figure B.7 below shows the comparison on a finer time-of-day basis. The graph compares the total 2000 generation by time of day for the coal units in the southeast in MAPS to the coal units in the southeast reported in the CEMS data. Although the totals are slightly different since not all units are reported, the daily patterns clearly mirror each other.

Figure B.7. 2000 Southeast Coal Capacity Time-of-Day Generation Pattern



Model results for the oil and gas units also matched actual operations fairly closely.

The final regional hurdle rates that were selected in the SEARUC analysis were \$10/MWh for the commitment decision and \$5/MWh for the dispatch. While these values differed slightly from the values determined in the NERTO analysis they were selected for use in the SMD analysis as representative of operation throughout the Eastern Interconnection. However, no wheeling rates were assumed within the existing ISOs (NY, NE and PJM).

The hurdle rates used in the western section of the US were based on a similar analysis performed in late 2002 for a confidential client. Our analysis showed that a long history of higher levels of regional interchanges than in the east resulted in lower values for the economic hurdle rates. Inter-regional values of

$5/MWH for commitment and $3/MWh for dispatch were selected as typical for WECC. As with the existing ISOs in the east, no wheeling rates were assumed within the California ISO.

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