IREMM, Inc.

Inter-Regional Electric Market Model

Electric Energy Price Benchmarks and Forecasts Through Simulation

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PROPOSAL FOR

BULK POWER ANALYTICAL SERVICES

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Submitted By:
IREMM, Inc.

Proposal for Bulk Power Analytical Services

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1.0 Introduction

IREMM's mission of providing the best analytical tools possible inspired us to develop a simulation model that can help answer fundamental questions about the future of the electric power industry. The Inter-Regional Electric Market Model (IREMM) is second to none in analyzing the ***business of power generation*** in a competitive bulk power market place. Using the IREMM model, you can:

- **Forecast bulk electric power prices;**
- **Determine the value of existing and/or planned generation resources;**
- **Evaluate the relative *Market Power* of buyers versus sellers;**
- **Evaluate *Market Power* resulting from projected mergers between electric power producers;**
- **Develop pricing strategies within a game theory framework;**
- **Analyze the effect of transmission constraints on market prices and *Market Power*;**
- **Evaluate purchase and sales opportunities;**
- **Quantify price risks for long and medium term transactions;**
- **Evaluate strategies for hedging electricity with other energy commodities;**
- **Identify potential buyers and sellers of energy and quantify the amount of energy exchanged;**
- **Identify generating resources with export potential;**
- **Evaluate the effect of increased or decreased load growth;**
- **Determine the viability of new generating resource strategies; and**
- **Identify likely candidates for retirement or deactivation.**

The restructuring electric power industry calls for new tools to analyze market issues and develop competitive strategies. Each organization generally has a wide range of analytical needs from many different internal clients. The matrix in Table 1 summarizes the insights that bulk power market participants can gain from IREMM tools. IREMM can help your company in at least three broad areas, as highlighted below:

1. **Bulk Power Marketing:** To participate successfully in the bulk power market, buyers need to assess whether the market price of purchased energy is a good deal, and sellers must determine whether competitively priced energy sales can generate sufficient revenues to cover production costs. The price of economy energy has become more visible through such sources as regional price surveys and on-line information services. In addition, forward cash markets and futures markets have developed that entitle buyers and sellers to sell electricity at future points in time. These forward markets reflect the collective wisdom of all active market participants, and market-clearing prices emerge through their interactions in the marketplace. One element of energy transactions that cannot be discovered by reviewing current market prices is risk. Risk needs to be quantified by analyzing the underlying variables. The IREMM model can help assess the risks associated with changes in many key variables.

2. **Corporate Strategic Planning:** IREMM provides a framework for understanding the competitive dynamics of bulk power markets, and presents planners and policy makers with a global view of the challenges of the structural changes facing the electric power industry. The IREMM model illustrates and quantifies the impacts of such changes, and can be used to analyze specific policy initiatives. IREMM enhances the credibility of bulk power market studies -- its broad scope and ability to simulate the actions and reactions of numerous company dispatch control centers provides a dynamic perspective on the competitive market. IREMM is an invaluable tool for strategic and policy analysis, because it crystallizes the many competing and complex factors in the industry **into prices and quantities**, two of the most important elements in a competitive market.

Strategic planning increasingly will require analyzing the interactions of all market participants, and evaluating how these interactions impact asset and business values. The analytical tools developed for use in rate negotiations with regulators are not sufficient to assist corporate decisions about pricing electricity competitively. Decision makers in the bulk power market need to address unconventional issues, such as partnering, mergers, acquisitions, divestiture, and a whole host of related market issues. In going forward, tools that can help chart a course through the unknown will become more valuable.

3. **Regulatory Interactions:** As the regulatory compact changes, the effects of policy and regulatory changes need to be evaluated within a comprehensive and logical framework. The implications of the structural changes being considered and implemented by policy makers for the North American electricity markets are not thoroughly understood. No other attempt at deregulation has involved an industry as large and complex. Other countries that have undertaken electric power deregulation have smaller electric systems, and it is easier to understand the effects of structural change than in the U.S. IREMM tools can help convey to regulatory decision makers the consequences of their actions, including merger policy, market power, state-by-state deregulation and the associated reciprocity issues, and transmission pricing.

4. **Environmental Allowance Markets:** As environmental emissions become more restricted and costly to comply with, the regulatory focus will be driven toward increased reliance on emission allowance trading systems. Once an emission allowance market is established, forecasts must be made of each type of emission to better understand their likely value. The value will be a function of the supply and demand of each type of allowance as well as the costs of alternative generation strategies that could be implemented to trade of emissions against other objectives. IREMM has the ability to forecast emissions from the entire electric power sector to provide credible forecasts including emission control strategies.

5. **Btu Markets:** As energy markets converge, it becomes necessary to analyze a broad based Btu market. This Btu market consists of the primary fuels that are used in electricity generation as well as the electrical energy itself. In many regions, electrical power production is the largest discretionary user of fuels and because of this degree of price elasticity the ability to understand and analyze this integrated market is valuable. IREMM can be used to analyze an integrated fuel and electricity based Btu market.

We trust that you will agree -- IREMM is indispensable for analyzing the ***business of power generation*** in a competitive bulk power market place.

Table 1: Insights Available using IREMM Tools

Key Report Findings / Power Industry Stakeholders	Valuation (Competitive-ness) of Existing Generation Assets	Economic Viability of Existing and Proposed Generation Assets	Valuation of Bulk Power Transactions	Bulk Power Purchase and Sale Quantities	Bulk Power Prices	Competitive Ranking of Bulk Power Producers	Air Emissions Levels	Fuel Consumption
Electric Utilities (incl Coops and REAs)	Asset divestiture; merger /acquisition; stranded asset identification	Understand competition	Buy vs. sell decision; profitability	Competitiveness implications; transmission constraints	Load growth and load loss; profitability level	Level of profitability	Abatement investment requirements	Amount and type; supply issues
Independent Power Producers	Merchant plant profitability	New merchant plant investment risk	Merchant plant profitability	Bulk power market breadth and depth; merchant plant viability	Future market impacts on profitability	Merchant plant location options		Amount and type; supply issues
Power Marketers			Deal viability	Deal viability	Deal viability	Competitor viability		
Financial Community	Valuation of companies / asset mark-to-market	Capital market financing requirements	Short term profitability of power producers	Short term profitability of power producers	Arbitrage opportunities; futures, options	Relative corporate survivability	Risk of exposure	Profitability of fuel providers
Economic Consultants	Regional economic implications	Regional economic implications	Regional economic implications	Transmission constraint effects on regional economics	Regional growth disparities		Impact on regional welfare	Regional resource allocation / extraction
Policy Makers	Regulated vs. deregulated asset recovery	Retail consumer protection	Effect of all wheeling	Competitiveness of local utility	Impact on retail consumer protection	Anti-trust; industry concentration	Compliance monitoring and impacts	Extractive industry needs
Fuel Providers	Contract renegotiation possibilities	Possible participation in projects; new customers	Contract renegotiation possibilities	Regional fuel consumption patterns		Viability of long term fuel purchase contracts and future opportunities	Impact of economic / required fuel switching	Threats and opportunities
Environmental Groups	Unit retirements / replacements	Compliance with regulations		Effects on environmental balance	Power imports / exports affect environmental balance	Power imports / exports affect environmental balance	Compliance issues - regional impacts	Fuel policies / volumes affect air emissions
Major Power Consumers (incl munis)	Buy vs. build; selection of power provider	New sources of supply		Price / reliability considerations	Location of Energy Intensive Facilities	Ability to negotiate prices		
Power Industry Suppliers	Ability to market products / services	Ability to market products / services		Infrastructure implications	Infrastructure implications	Target market identification	Infrastructure requirements	Infrastructure requirements

2.0 The IREMM License

The license to use the IREMM program includes:
- The monthly version of the IREMM model;
- The hourly version of the IREMM model;
- The data needed to produce forecasts that extend ten years into the future.

The IREMM model is very flexible and adaptable.
- Data are organized in a Microsoft Access Database;
- Microsoft Access data linkage to Resource Data International's BASECASE™ Data Service
- All data inputs can be modified, replaced, and expanded;
- Spreadsheet templates are available to facilitate analysis of the results;
- The forecast horizon can be easily extended beyond ten years;
- The model is fast, facilitating multiple scenario analysis.

Training:
- IREMM staff provide the training and technical guidance to enable you to conduct market studies;
- Training costs are included in the annual license fee.
- The license fee includes unlimited telephone technical support.

Cost:
- Annual license fee: US$22,500, plus travel expenses for training.
- Unrestricted number of users within a corporate entity in the same metropolitan area.
- Additional site licenses available for US$ 7,500.
- Includes both the monthly and hourly versions of the IREMM model.
- Consultant's License:
  - US$7,500 for first three projects in a one-year period;
  - US$3,500 for each additional project in the first year.
- Trial license fee: US$3000, plus travel expenses for training.
  - Includes use of all features of the full IREMM model for 30 days;
  - Includes two days of customized training;
  - Credited toward the annual license fee, or the fee for the first project.

3.0 The Inter-Regional Electric Market Model

- IREMM is a comprehensive computer program that forecasts market-clearing economy energy prices.
- IREMM simultaneously analyzes all market areas within an interconnected system.
- IREMM focuses on the behavior of participants in competitive bulk power markets.
- IREMM's focus on price distinguishes it from traditional planning and operations models.

Production simulation and market-clearing prices. The IREMM model performs the functions typically associated with electric power production simulation programs, such as unit dispatch, maintenance scheduling, cost accounting, and report preparation. However, the IREMM model's functionality surpasses other simulation programs by calculating market clearing prices and identifying the economic energy transactions that result from the interaction of supply and demand for energy. In all markets, price is set by someone's costs somewhere, but not necessarily by the buyer's or seller's costs.

Economic gain and market power. In a competitive market, each company attempts to maximize its economic gain, which consists of profits on sales and/or savings on purchases. The IREMM model maximizes gains over all companies within each interconnected system, constrained by supply and demand. With this approach, IREMM provides the means to analyze the relative market power of buyers and sellers.

Game theory and strategic planning. IREMM uses a game theory framework, assuming an ideal market in which all participants have access to price information. Within this framework, minimum profit before sale strategies can be tested to evaluate winners and losers. Thus, IREMM can help market participants to develop strategies for capturing a larger share of the total gains.

Prevailing market prices. IREMM employs a unique methodology to auction relatively low cost energy resources to the highest bidders. The auction process yields forecasts of prevailing bulk power market-clearing prices for energy transactions, assuming a level playing field for all participants.

Depth and breadth of IREMM.

- IREMM includes virtually all electric generating units in North America and northern Mexico.
- IREMM includes all market areas in each Interconnected System.

Depth and breadth of analysis. IREMM is unique both in the depth and breadth of its analysis. The model's depth arises from using **unit level** data, while analytical breadth derives from including *all* market participants in each interconnected system. IREMM examines market relationships dynamically and monitors the impact of transactions on individual generating units, thereby replicating the market realities that bulk power buyers and sellers must deal with every day. Thus, IREMM enables users to analyze the bulk power marketplace in great detail.

a. Generating unit level data. IREMM employs detailed unit level data, including the effects of off-system sales and/or purchase opportunities, and produces summary reports of unit-by-unit dispatches. Reports are available for states, companies and/or market areas, both before and after transactions.

b. The Interconnected System. IREMM provides a strategic perspective that conventional production costing models lack. Production costing models typically study limited segments of the potential market areas within the interconnected system. Models which fail to represent all companies within an interconnected system (such as the entire Eastern Interconnected System) must rely on simplifying assumptions about the price and availability of bulk power.

Conversely, many large-scale econometric models favor analytical breadth over detail. Such models neglect unit and/or company level data in their estimation of regional energy production, fuel consumption, plant emissions or cost-of-electricity forecasts. They are suitable for use in macroeconomic analysis, but are inadequate for understanding market opportunities.

c. Purchase and Sales Opportunities. A key feature of the IREMM model is its ability to evaluate how specific market areas respond to price signals. This feature is illustrated in Table 2 below, for the companies in MAAC (PJM). In this case, MAAC purchases 12,358 GWh in 1998 from six other market areas.

Table 2: Quantities of GWhs Purchased by a Market Area Showing Their Suppliers

Summary of Buyers for Calendar Year 1998

GWhs

<MAAC> <MAAC> was a Buyer

Seller	JAN	FEB	MAR	APR	MAY	JUN	JLY	AUG	SEP	OCT	NOV	DEC	TOTAL
APS	254.6	227.5	98.7	194.6	97.4	36.6	128.3	108.6	96.0	166.2	328.3	373.4	2110.2
CAPC	994.6	788.7	650.3	756.5	772.3	483.5	735.1	707.2	542.9	770.8	551.6	984.4	8738.0
DP&L	10.9	6.5	.	.	.	.	.	.	.	.	.	.	17.4
UPNY	.	.	.	33.1	.	.	.	.	.	.	.	.	33.1
SENY	.	.	.	51.4	.	.	.	.	.	.	.	.	51.4
VACR	518.7	354.0	33.0	20.9	82.8	.	.	.	.	.	265.1	133.6	1408.2
Total	1778.8	1376.7	782.1	1056.6	952.5	520.1	863.5	815.8	638.9	937.0	1145.0	1491.3	12358.2

Summary tables are available that show how much energy each supplier sells, and to whom the energy is sold. For example, Table 3 indicates that AEP sold 16,683 GWhs in 1998 to 15 other market areas.

Table 3: Quantities of GWhs Sold by a Market Area Showing Their Customers

Summary of Sellers for Calendar Year 1998

GWhs

<ECAR> <AEP > was a Seller

Buyer	JAN	FEB	MAR	APR	MAY	JUN	JLY	AUG	SEP	OCT	NOV	DEC	TOTAL
AMPO	331.1	338.0	383.2	389.0	294.1	341.5	428.5	428.7	299.1	414.1	380.3	305.0	4332.7
BUCK	.	.	.	.	69.6	8.3	11.3	9.1	111.9	.	.	.	210.2
CG&E	.	.	.	2.1	.	.	26.3	20.4	.	.	.	.	48.7
CP	282.1	251.9	123.8	204.9	94.8	12.4	26.5	135.1	186.1	158.2	76.3	459.3	2011.4
DP&L	.	.	.	1.5	.	.	.	.	.	.	.	.	1.5
DECO	.	.	.	.	.	.	38.1	16.7	.	.	.	.	54.8
EKPC	71.8	.	26.8	.	.	.	8.9	22.5	.	46.6	.	.	176.6
IMPA	.	.	20.6	43.9	3.0	7.3	38.6	7.0	1.4	.	.	.	121.9
MCCP	.	.	.	0.2	.	.	.	.	.	0.2	0.7	.	1.1
OVEC	.	.	5.8	.	7.7	.	22.4	34.7	.	.	.	.	70.6
WVPA	29.3	29.4	54.0	71.3	54.6	46.4	103.5	45.2	40.2	73.4	16.0	29.1	592.4
CECO	694.7	1449.1	1278.4	642.9	.	319.9	353.8	563.7	.	656.9	1057.1	749.6	7766.0
WUMS	.	.	.	.	.	.	.	.	.	.	5.6	.	5.6
TVA	.	.	.	.	.	.	5.3	.	.	.	.	.	5.3
VACR	.	.	11.2	280.8	109.3	44.3	364.1	344.6	130.1	.	.	.	1284.4
Total	1409.0	2068.4	1903.8	1636.5	633.0	780.1	1427.3	1627.6	768.8	1349.5	1536.0	1543.1	16683.1

The Monthly IREMM Model

For each load period: off-peak, on-peak, and peak, IREMM forecasts "bid" and "ask" prices for each month. These forecasted bulk power market-clearing prices represent typical median, or 50th percentile, prices prevailing for energy as a kWh commodity.

The monthly version is useful for evaluating the broader and longer term issues associated with the electric power sector. It is useful for looking at issues such as fuel consumption trends, fuel price elasticity and prevailing market price for energy, asset values due to energy production potential for base and intermediate units.

Monthly Forecasts of Market Clearing Prices. Given purchase and sales opportunities, the willingness of buyers to purchase energy and of sellers to sell energy at different prices can be determined, and forward price curves can be developed. Table 4 shows three years of market-clearing prices for Houston Lighting and Power. The seasonal trend in the market prices reflects the underlying gas price profile.

Table 4: Forecast of Market Clearing Prices in $/MWh

STUDY SUMMARY OF BID AND ASK PRICES FOR <HL&P>

YEAR	LOAD LEVEL / CATEGORY	JAN	FEB	MAR	APR	MAY	JUN	JLY	AUG	SEP	OCT	NOV	DEC
1997													
off-peak	Ask Price (sales)	27.75	25.00	22.50	21.75	21.25	21.25	21.50	21.75	22.25	23.50	25.50	27.75
	Bid Price (purch)	24.25	21.50	19.00	19.25	17.75	18.00	18.50	18.75	18.75	19.75	22.00	23.75
mid-peak	Ask Price (sales)	28.25	25.50	23.00	21.75	21.25	21.50	21.75	22.00	22.25	23.75	25.75	27.75
	Bid Price (purch)	27.75	25.00	19.50	19.25	19.25	21.25	21.50	21.75	22.25	20.00	22.25	24.00
on-peak	Ask Price (sales)	28.50	25.50	23.00	21.75	21.75	21.50	22.00	22.00	22.50	23.75	25.75	28.00
	Bid Price (purch)	28.25	25.00	19.50	19.25	21.50	21.25	21.75	21.75	22.25	20.50	22.50	24.50
1998													
off-peak	Ask Price (sales)	28.50	25.75	23.50	22.25	21.75	21.75	22.00	22.25	22.75	24.00	26.00	28.50
	Bid Price (purch)	25.00	22.25	19.75	18.50	18.25	18.50	19.00	19.25	19.25	20.50	22.75	24.50
mid-peak	Ask Price (sales)	29.00	26.00	23.50	22.25	21.75	22.00	22.50	22.75	22.75	24.50	26.50	28.50
	Bid Price (purch)	28.50	25.75	19.75	18.75	19.25	21.75	22.00	22.25	22.75	20.75	22.75	24.75
on-peak	Ask Price (sales)	29.25	26.00	23.50	22.25	22.25	22.25	22.50	22.75	23.00	24.50	26.50	26.25
	Bid Price (purch)	29.00	25.75	20.75	19.25	21.75	21.75	22.50	22.75	22.75	24.50	26.00	25.25
1999													
off-peak	Ask Price (sales)	29.25	26.25	24.00	22.75	22.50	22.50	22.00	22.50	21.75	24.75	27.25	29.25
	Bid Price (purch)	25.75	22.75	20.25	19.25	19.00	19.25	19.75	20.50	20.00	21.00	23.50	25.50
mid-peak	Ask Price (sales)	29.75	26.75	24.25	22.75	22.50	22.50	23.00	23.25	23.25	25.00	27.25	29.25
	Bid Price (purch)	29.25	26.25	20.75	19.25	19.25	22.50	22.50	22.75	23.25	24.75	23.75	25.50
on-peak	Ask Price (sales)	27.75	26.75	24.75	22.75	22.75	22.75	23.00	24.00	23.75	25.25	27.75	29.50
	Bid Price (purch)	29.75	26.25	21.25	20.25	22.50	22.50	23.00	23.25	23.50	25.00	27.25	26.00

Figure 1 presents a forecast of energy prices produced by the monthly version of IREMM. Figure 2 compares the forecasted prices to the dispatch cost of a generating resource, or strike price in a purchase/sale contract.

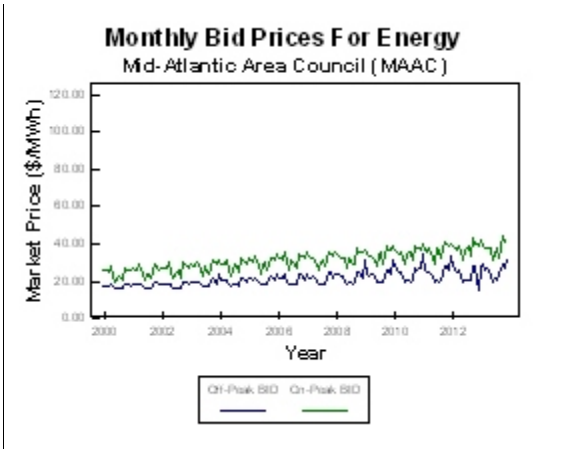

Figure 1: Price Series. Showing IREMM Bid prices for the entire MAAC Region from the Monthly Version

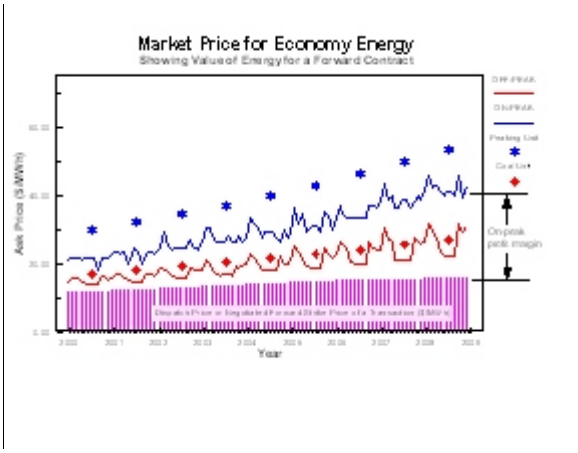

Figure 2: Price Series. Showing IREMM Bid prices in Relation to the Dispatch price of a future unit.

Figures 3(a) and 3(b) show the contributions to fixed costs over a specific time period. Figure 3(a) shows the cumulative contributions to fixed costs for all of a company's assets, and figure 3(b) shows the annual values.

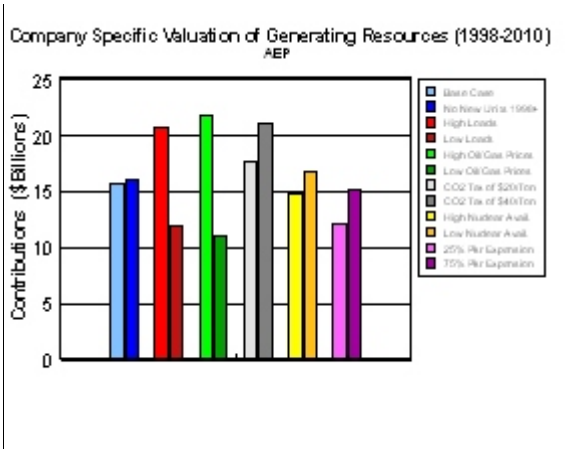

Figure 3a: Cumulative contributions to fixed costs for AEP for 1998 through 2010 under various scenarios

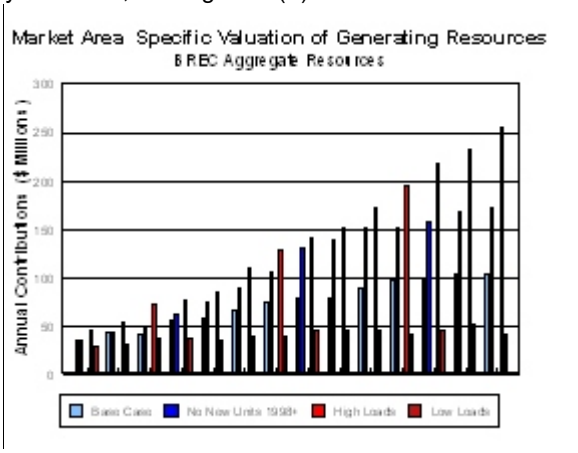

Figure 3b:Annual contributions to fixed costs over the time period 1998 through 2010 for four scenarios

Figures 4(a) and 4(b) show regional transactions between a market area, MAAC, and the external world. This market area could be reduced in size to include only one merchant plant, enabling its import / export characteristics to be easily reported. Figure 4(a) shows transactions by load level, and figure 4(b) reports the profits on sales and savings on transactions.

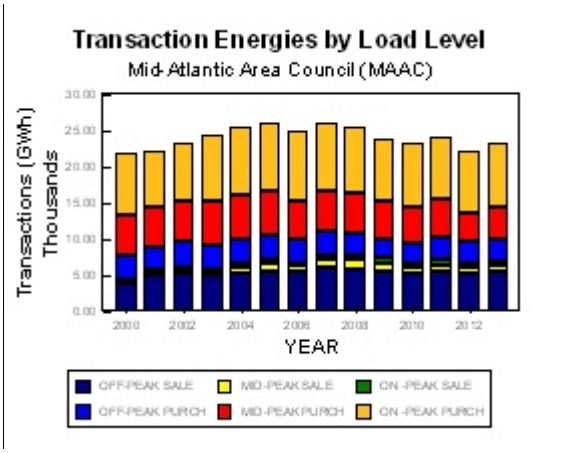

Figure4a: Transaction Energy showing the amounts of energy bought and sold outside of the MAAC Region.

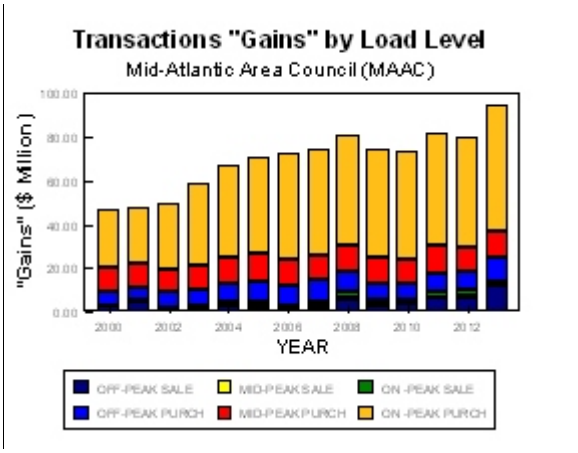

Figure4b: Profits on Sales and Savings on Purchases from transaction energies

Figures 5(a) and 5(b) show the average revenues on sales and average expense for purchased energy. Figure 5(b) shows the average savings per MWh for purchases, and the average profit per MWh on sales. The IREMM Model produces a great deal of information that provides insights into the dynamics of bulk electric power markets in the future.

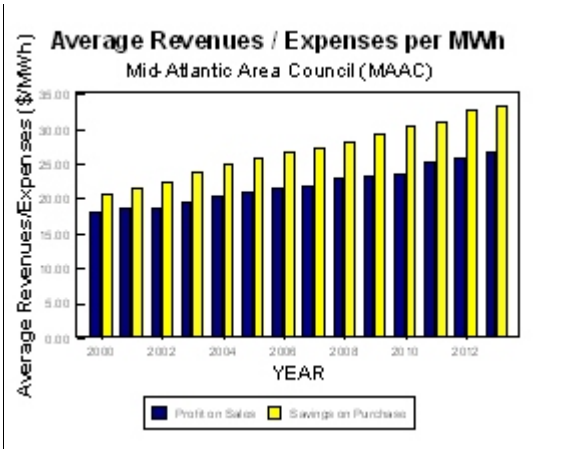

Figure 5a: Revenues per MWh sold and Expenses per MWh purchased based on the transaction energies

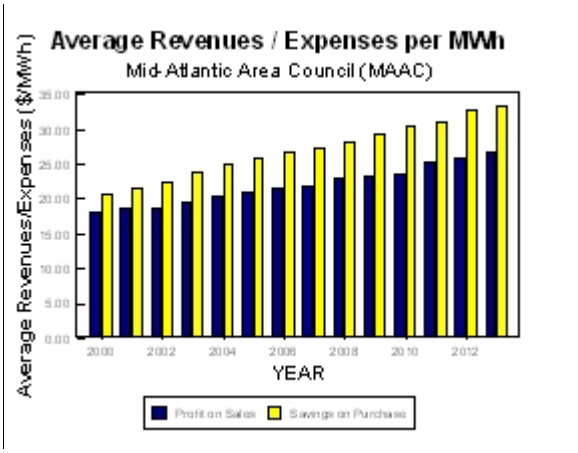

Figure 5b: Profits Margin per MWh sold and Savings per MWh purchased based on the transaction energies

The Hourly IREMM Model

The hourly version of IREMM provides greater detail, and enables users to evaluate price volatility and risk associated with the forecast. Figure 6 illustrates the prices output from the hourly version of the IREMM model under seven scenarios.

Figure 6(a) shows prices for Cinergy in August 1998 under three sensitivity cases: base case and higher and lower unit availability. Figure 6(b) illustrates prices under the remaining four cases: severe/mild weather and higher/lower oil and gas prices. This type of analysis can help to estimate price volatility in future periods.

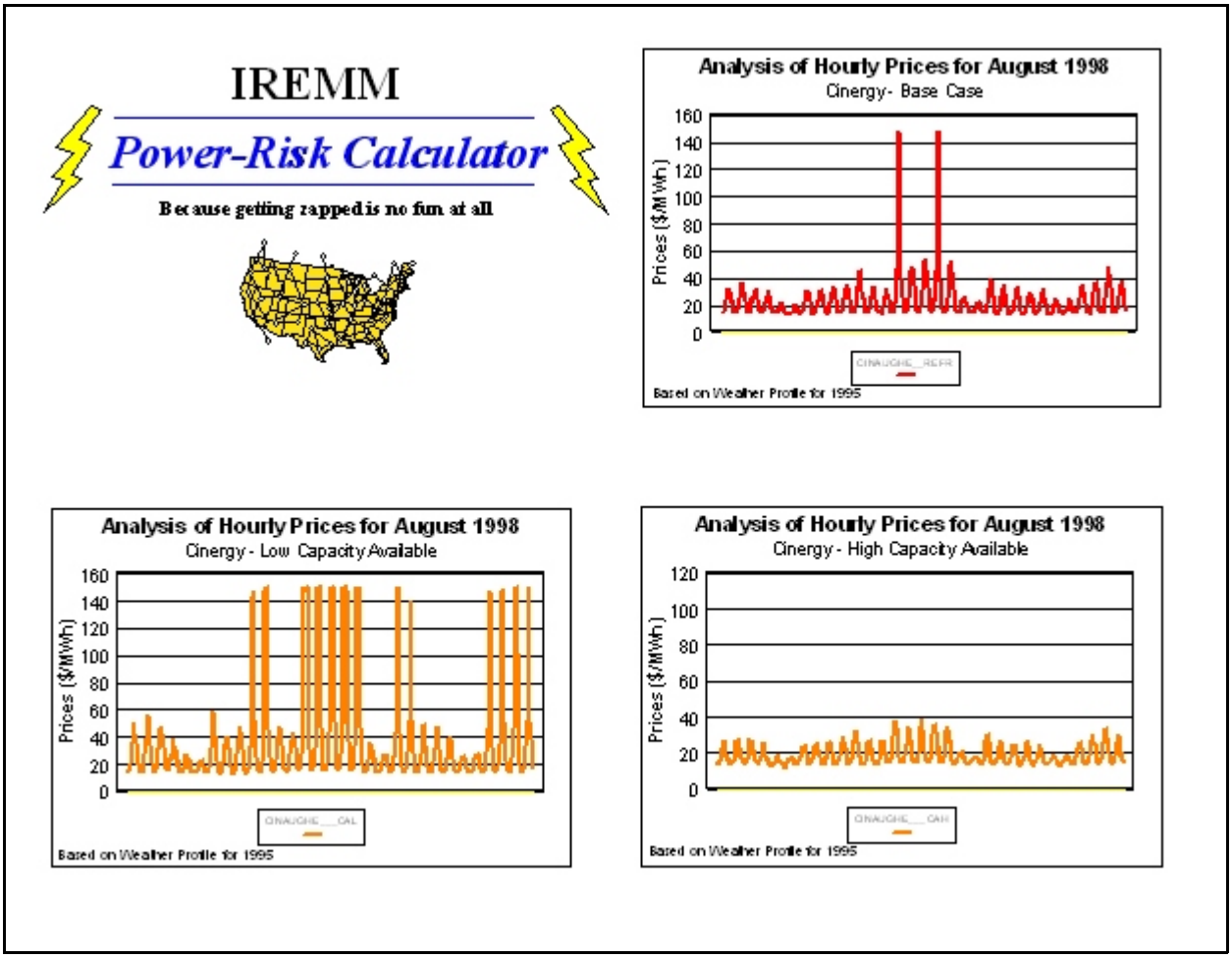

Figure 6a: Prices from the Hourly Model for Cinergy 1998 under the base case and the impact of higher and lower unit availability scenarios.

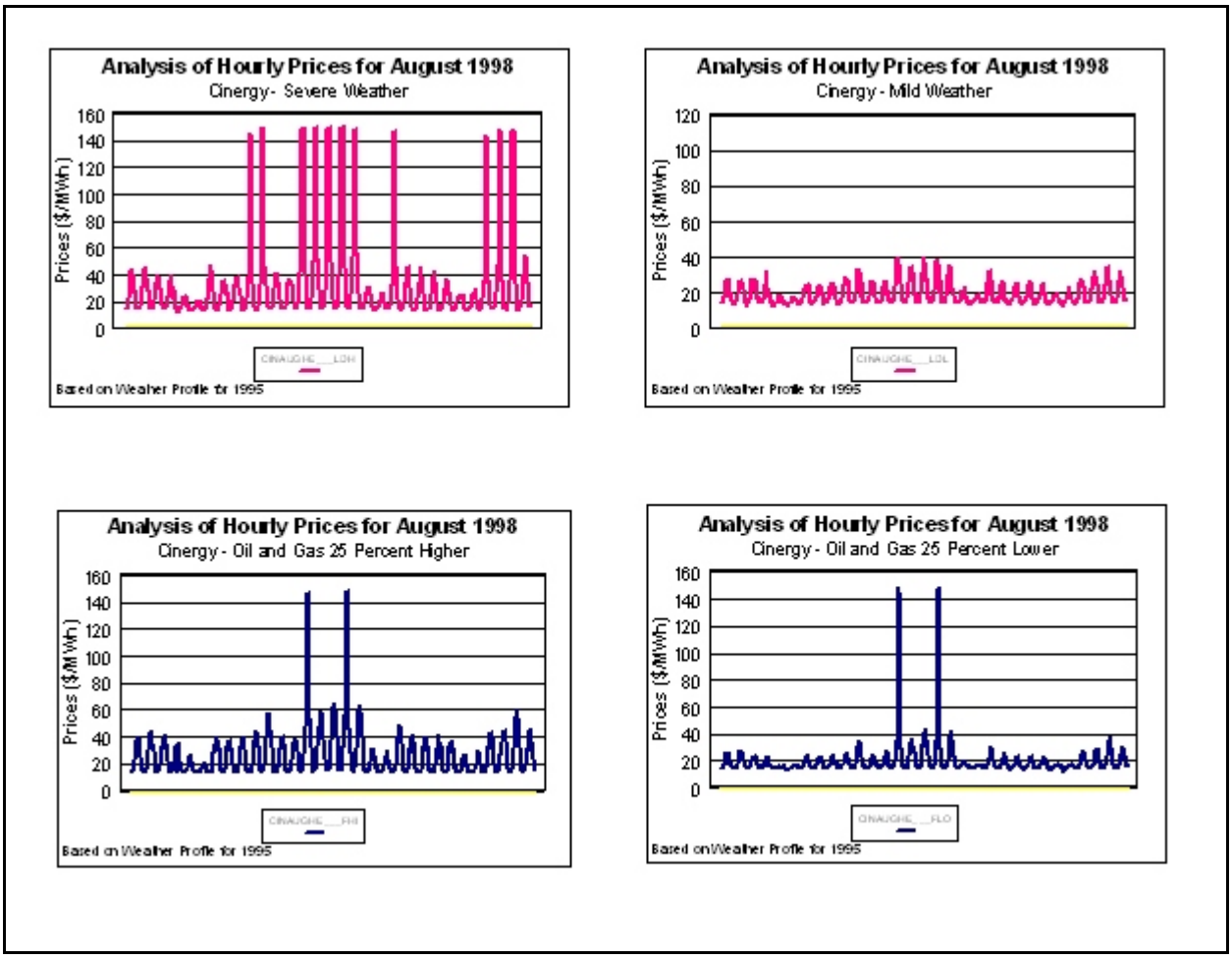

Figure 6b: Prices from the Hourly Model for Cinergy 1998 under the severe / mild weather and base case and the impact of higher and lower oil and gas prices.

Forecasts of Hourly Market Clearing Prices. Given purchase and sales opportunities, the willingness of buyers to purchase energy and of sellers to sell energy at different prices can be determined, and forward price curves can be developed. Hourly chronological prices are voluminous and need to be summarized to communicate their characteristics effectively.

Chronological Price Distributions. The results of the Hourly IREMM simulations can be presented in many ways and with varying amounts of detail. Figure 7 shows a weighted average hourly chronological stream of prices for a base case and four perturbation cases. The perturbation cases are used to assess the impact of deviations from the base case conditions. This graph depicts the volatility expected as a function of supply, demand, and pricing strategies. Regardless of whether a specific market area is summer or winter peaking, markets in the interconnected system create conditions in which prices can be expected to surge in the summer.

Figure 8 presents the same price stream with prices averaged across 16 hour on-peak blocks for Monday through Friday.

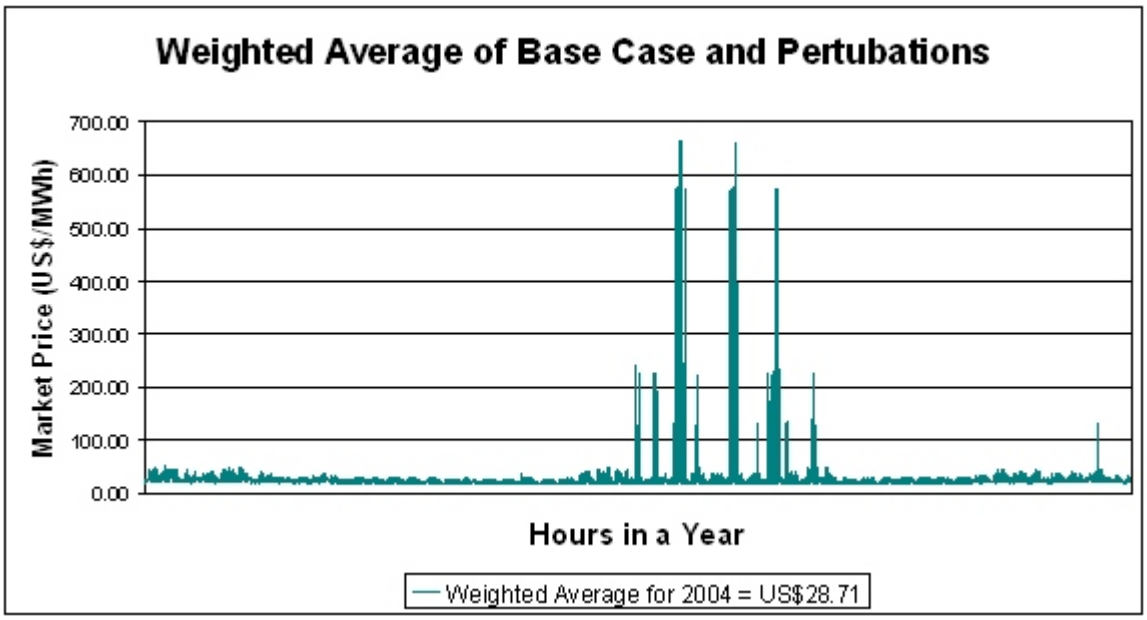

Figure 7: Hourly chronological prices for a market area in 2004. Weighted Average of Reference Case and Sensitivity Case Perturbations

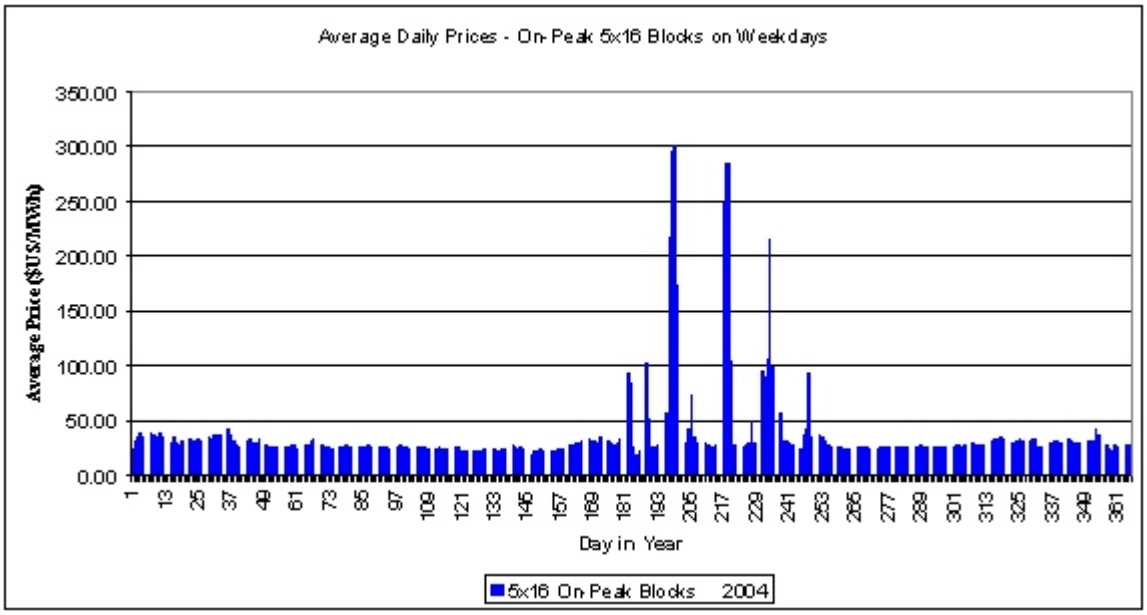

Figure 8: Chronological on-peak (1x16) prices for a market area in 2004. Weighted Average of Reference Case and Sensitivity Case Perturbations

Chronological price graphs provide a great deal of detail. Another way to present the price forecasts is via monthly summary statistics such as the mean, standard deviation and the min/max range. Figure 9 shows these statistics across the eleven year horizon of the study. The effect of unit additions in the n 2006 is clearly evident in the statistics, with a reduction in the standard deviation beginning in the year 2006.

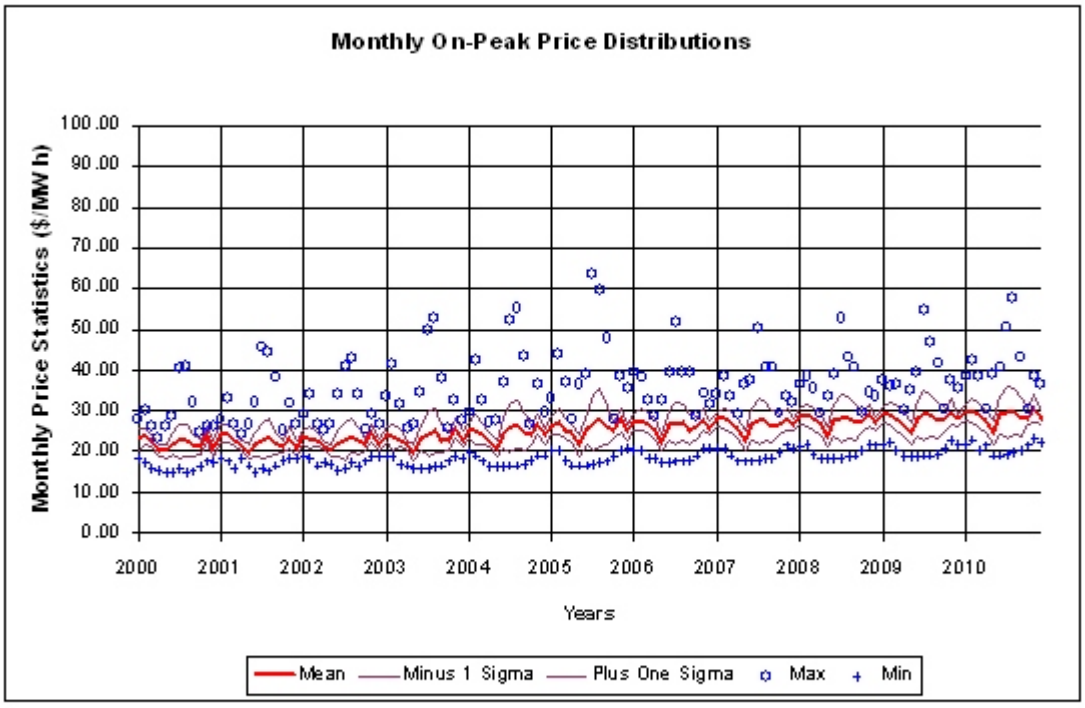

Figure 9: Price distributions for a ten year forecast.

Forecasts of Fuel Consumption. The richness of detail in the hourly model makes it easy to extract the hourly fuel consumption, as well as monthly and annual summaries. Figure 10 shows hourly fuel consumption for a market area for one month. This information can be used to estimate the value of pipeline capacity, and assist in the decision to purchase firm gas transportation or purchase gas on the spot market.

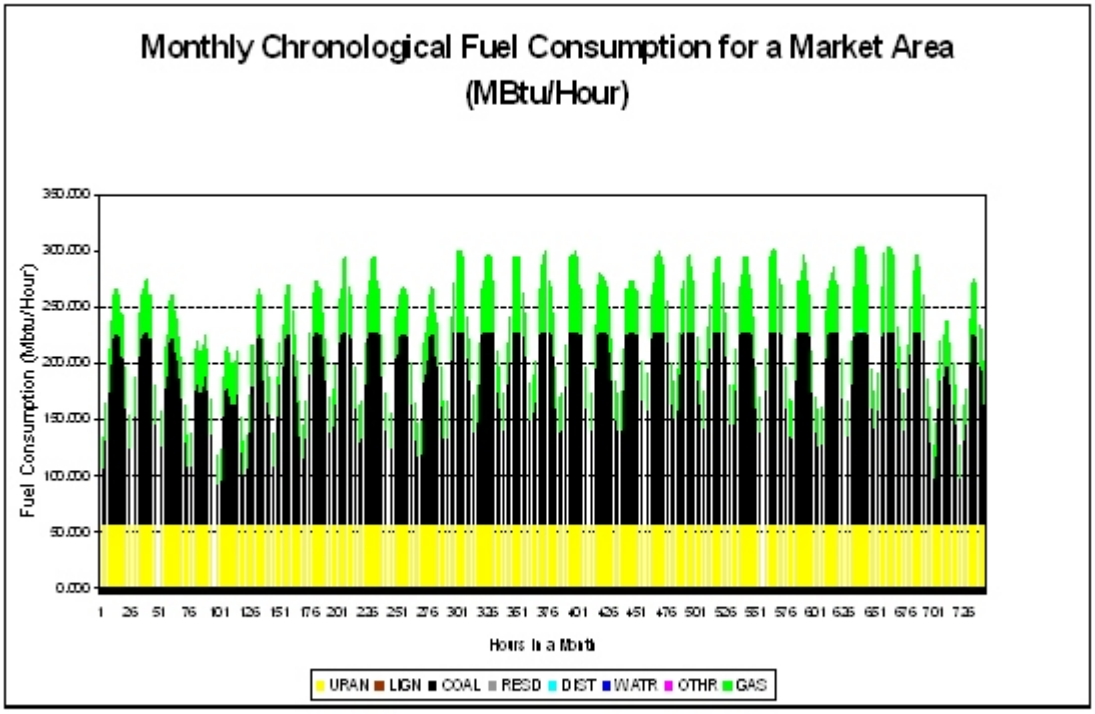

Figure 10: Hourly Fuel consumption for a specific market area for the month of July

Pricing Options

Strike Price and Demand Charges. IREMM calculates demand charges from the difference between the strike price and market clearing prices. Energy transfers are informative, but do not communicate the most important piece of information to buyers and sellers -- price.

Market-clearing prices can be expressed in terms of demand charges ($ per kW-yr), obtainable if energy is contracted at a specific strike (or dispatch) price. When the market price is above the strike price, the difference confers value to the buyer, and the seller loses the opportunity to sell energy at the higher market price. When the difference is manifested as an up-front demand charge (or options price), both the buyer and the seller are indifferent between the agreed-upon strike price plus demand charge, and the spot market price.

The overall effect of such transactions is to equalize risk between the buyer and the seller. IREMM can quantify demand charges (or options payments) under a wide range of scenarios to help companies and marketers assess their risks. The strike price is often the dispatch cost of a generating resource. Frequently, an up-front demand charge is required in addition to an agreed upon energy strike price in order to achieve an equivalent market price. Table 5 shows demand charges for an annual transaction at a strike price of $15.00 per MWh.

Figure 11 depicts the impact of unit dispatch vs price, as well as the cumulative value of energy at a specific strike price, providing a more dynamic view of IREMM results.

Table 5: Demand Charges (Options Price) for Non-Firm Energy at a Specified Strike Price

SUMMARY OF DEMAND CHARGES ($/kW-yr) FOR A SPECIFIED STRIKE PRICE OF < $15.00/MWh>

COMP	1995	1996	1997	1998	1999	2000	2001	2002	2003	Average
APS	35.1	38.5	42.6	47.5	53.3	63.1	71.4	82.9	94.7	58.8
AEP	29.7	32.4	37.4	43.7	50.5	61.2	66.0	75.0	85.5	53.5
AMPO	31.5	35.9	39.3	44.7	51.2	64.4	70.8	80.0	95.6	57.1
BREC	12.1	14.7	18.3	20.4	27.2	39.3	44.1	52.1	65.2	32.6
BUCK	32.3	36.2	41.2	46.7	53.7	67.3	76.9	85.8	98.3	59.8
CAPC	34.2	36.2	40.7	44.9	51.6	61.2	69.9	80.6	94.1	57.0
CG&E	29.6	33.0	35.4	38.7	42.8	54.3	61.0	68.5	85.3	49.9
CP	69.6	74.3	76.8	74.3	82.5	93.0	98.6	110.9	123.3	89.3
DP&L	29.7	33.1	35.5	38.7	43.0	52.4	60.5	70.7	86.9	50.1

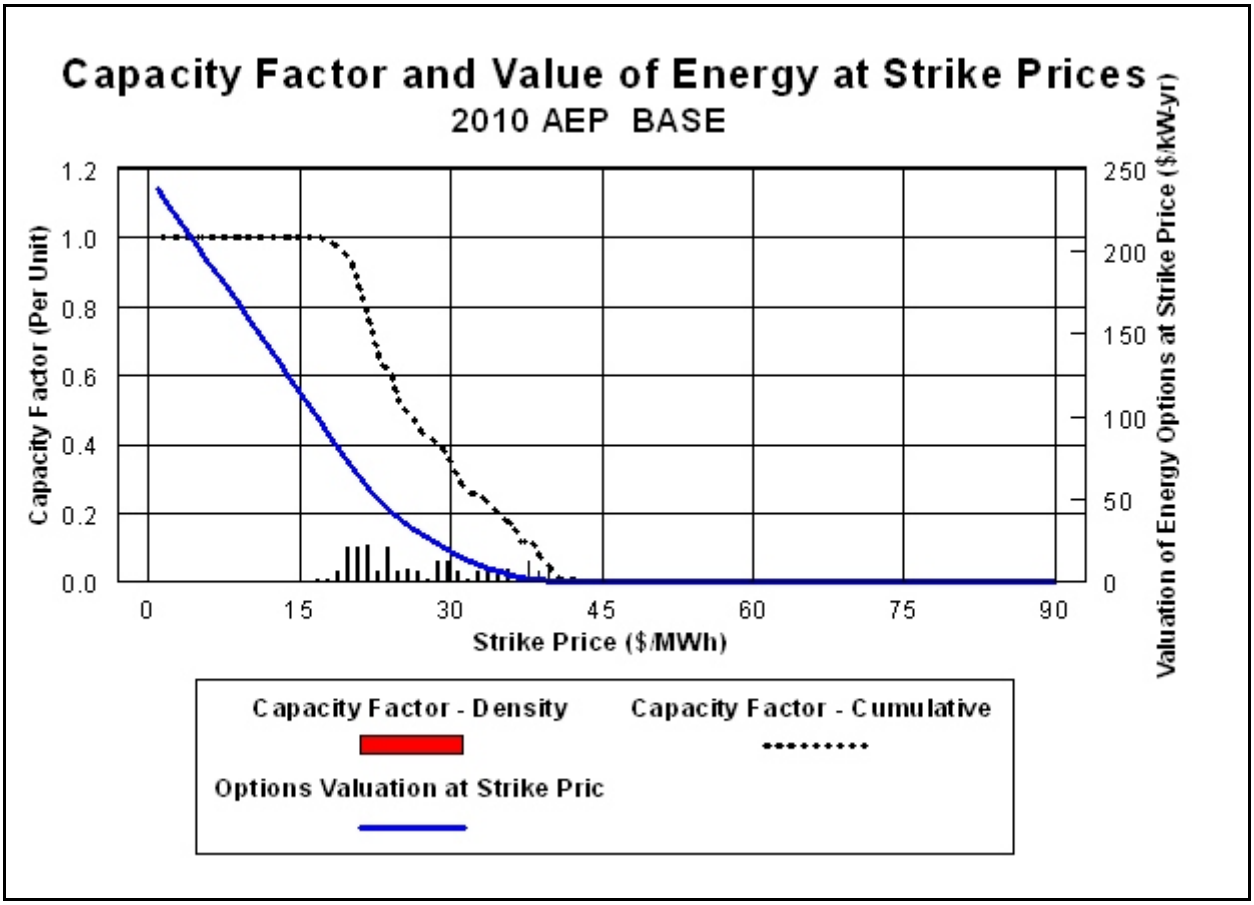

Figure 11: Illustration of unit capacity factor vs dispatch price and the resulting value of energy at a specific price level.

Resource Dispatch

Profitability and Competition. The profitability of individual generating resources is determined by market forces in the competitive electric power market. The IREMM model forecasts prices and ultimately, predicts the profitability of new and existing resources in such an environment.

IREMM provides many different levels of reporting detail, as shown in tables 6 through 8 for Louisville Gas and Electric. Table 6 shows the unit dispatch before purchase and sales opportunities. Table 7 shows

the units that can produce competitive energy economically in support of external sales. Table 8 reports the unit dispatch after transactions, along with an accounting of purchased energy expenses, revenues on sales, and fuel costs.

Table 6: Unit Level Dispatch Before Transactions - 1997

<LG&E> 1997 ANNUAL BEFORE TRANSACTIONS DISPATCH SUMMARY

UNIT NAME		TECH	FUEL	ALT	MW	$/MWH	R	JAN	FEB	MAR	APR	MAY	JUN	JLY	AUG	SEP	OCT	NOV	DEC	TOT. GWh	C.F.
AGGR. PUMPED STORAGE		PS	WAT		0.0	0.00		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
AGGR. CONV HYDRO		HY	WAT		41.0	0.00		11	10	11	10	11	11	12	12	11	11	10	11	132	0.367
MILL CREEK	4	ST	COL		466.0	12.75		318	287	318	307	318	307	318	318	307	.	231	318	3345	0.820
CANE RUN	6	ST	COL		240.0	12.86		164	148	164	.	123	158	164	164	158	164	158	164	1727	0.821
MILL CREEK	3	ST	COL		386.0	12.88		257	237	.	191	245	246	261	258	224	263	255	258	2696	0.797
TRIMBLE COUNTY	1	ST	COL		371.0	12.88		143	142	189	.	145	185	212	202	150	242	170	142	1922	0.592
CANE RUN	5	ST	COL		168.0	13.37		15	12	94	108	25	49	76	67	32	81	14	.	574	0.390
MILL CREEK	1	ST	COL		303.0	13.46		0	0	69	135	10	45	71	59	32	51	.	14	486	0.183
MILL CREEK	2	ST	COL		301.0	13.63		.	.	1	27	.	9	28	20	3	1	1	.	92	0.035
CANE RUN	4	ST	COL		155.0	14.19		.	.	.	.	.	.	1	0	.	.	.	.	1	0.001
WATERSIDE	8	GT	NG*		16.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
ZORN	1	GT	NG*		16.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
CANE RUN	11	GT	NG*	FO2	16.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
WATERSIDE	7	GT	NG*		17.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
PADDY'S RUN	11	GT	NG*		17.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
PADDY'S RUN	12	GT	NG*		26.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
ENERGY (GWh)								908	835	845	779	877	1012	1143	1101	918	813	839	905	10975	
PRODUCTION COST($ MILLION) (FUEL/O&M)								11.5	10.6	10.8	10.0	11.1	12.9	14.6	14.1	11.7	10.4	10.6	11.5	139.8	

Table 7: Increases and Decreases in Unit Level Dispatch Due to Transactions - 1997

<LG&E> 1997 ANNUAL SUMMARY OF UNITS AFFECTED BY TRANSACTIONS

UNIT NAME		FUEL	ALT	CAP-MW	$/MWh	R	JAN	FEB	MAR	APR	MAY	JUN	JLY	AUG	SEP	OCT	NOV	DEC	DELTA GWh
CANE RUN	6	COL		240	12.86		.	.	.	.	.	.	.	.	0	.	.	.	0
MILL CREEK	3	COL		386	12.88		6	1	.	.	18	9	2	5	31	.	.	5	76
TRIMBLE COUNTY	1	COL		371	12.88		109	87	1	.	108	60	41	50	95	11	74	111	747
CANE RUN	5	COL		168	13.37		100	91	20	2	89	61	39	48	78	33	70	.	632
MILL CREEK	1	COL		303	13.46		206	187	138	65	196	155	135	148	168	155	.	141	1694
MILL CREEK	2	COL		301	13.63		154	.	204	172	205	189	177	185	195	204	197	205	2087
CANE RUN	4	COL		155	14.19		106	95	106	102	106	102	104	106	64	.	77	106	1073
Changes in Output (GWh)							681	461	469	341	722	576	498	540	632	404	418	569	6310
Expenses for Purchases ($ Miln)							0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Revenues on Sales ($ Miln)							-11.9	-8.1	-8.3	-5.8	-12.4	-9.8	-8.4	-9.2	-10.6	-7.2	-7.4	-9.9	-109
Changes in Fuel and O&M($ Miln)							9.2	6.2	6.4	4.7	9.8	7.8	6.8	7.3	8.5	5.5	5.7	7.7	85.5

Table 8: Unit Level Dispatch After Transactions - 1997

<LG&E> 1997 ANNUAL AFTER TRANSACTIONS DISPATCH SUMMARY

UNIT NAME		TECH	FUEL	ALT	MW	$/MWH	R	JAN	FEB	MAR	APR	MAY	JUN	JLY	AUG	SEP	OCT	NOV	DEC	TOT. GWh	C.F.
							M	Unit Dispatch (GWh)													
AGGR. PUMPED STORAGE	PS		WAT		0.0	0.00		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
AGGR. CONV HYDRO	HY		WAT		41.0	0.00		11	10	11	10	11	11	12	12	11	11	10	11	132	0.367
MILL CREEK	4	ST	COL		466.0	12.75		318	287	318	307	318	307	318	318	307	.	231	318	3345	0.820
CANE RUN	6	ST	COL		240.0	12.86		164	148	164	.	123	158	164	164	158	164	158	164	1727	0.821
MILL CREEK	3	ST	COL		386.0	12.88		263	238	.	191	263	255	263	263	255	263	255	263	2771	0.820
TRIMBLE COUNTY	1	ST	COL		371.0	12.88		253	228	190	.	253	245	253	253	245	253	245	253	2670	0.821
CANE RUN	5	ST	COL		168.0	13.37		115	103	115	111	115	111	115	115	111	115	83	.	1206	0.820
MILL CREEK	1	ST	COL		303.0	13.46		207	187	207	200	207	200	207	207	200	207	.	155	2180	0.821
MILL CREEK	2	ST	COL		301.0	13.63		154	.	205	199	205	199	205	205	199	205	199	205	2179	0.826
CANE RUN	4	ST	COL		155.0	14.19		106	95	106	102	106	102	106	106	64	.	77	106	1075	0.792
WATERSIDE	8	GT	NG*		16.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
ZORN	1	GT	NG*		16.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
CANE RUN	11	GT	NG*	FO2	16.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
WATERSIDE	7	GT	NG*		17.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
PADDY'S RUN	11	GT	NG*		17.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
PADDY'S RUN	12	GT	NG*		26.0	46.65		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
ENERGY (GWh)								1589	1296	1314	1120	1599	1588	1641	1641	1550	1217	1257	1474	17285	
Fuel and O&M ($ Miln)								20.7	16.8	17.2	14.7	20.9	20.7	21.4	21.4	20.2	15.9	16.3	19.2	225.4	
Expenses for Purchases ($ Miln)								0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Revenues on Sales ($ Miln)								-11.9	-8.1	-8.3	-5.8	-12.4	-9.8	-8.4	-9.2	-10.6	-7.2	-7.4	-9.9	-108.9	
Resulting Net Fuel and O&M ($ Miln)								8.8	8.7	8.9	8.9	8.5	10.9	13.0	12.2	9.6	8.6	8.9	9.3	116.5	

Contributions to Fixed Costs. Once market clearing prices are determined, the value of energy from specific resources can be calculated. This value is the difference between the market price and the dispatch cost, multiplied by the amount of energy generated. Table 9 provides an example of the contributions to fixed costs for selected units owned by the Tennessee Valley Authority.

Table 9: Unit Level Contributions to Fixed Costs / Profitability

Contributions to Fixed Cost For TVA

Comp	Unit Name		Plant	Tech	Fuel-Type Pri	Fuel-Type Sec	Max Cap (Sum MW)	1995	1996	1997	1998	1999	2000	2001	2002	2003	Annual Avg. ($/kw-yr)
TEVA	SEQUOYAH	2	6152	NP	UR		1148.0	89.2	92.5	96.3	100.8	103.4	115.1	113.6	119.2	133.0	93.20
TEVA	SEQUOYAH	1	6152	NP	UR		1148.0	86.7	89.8	93.7	98.3	107.1	114.2	114.7	120.8	129.8	92.43
TEVA	WATTS BAR	1	3419	NP	UR		1170.0	70.9	94.7	98.6	103.3	103.7	114.6	117.8	123.7	136.3	91.51
TEVA	SHAWNEE	10	1379	ST	COL		140.0	8.7	9.3	9.7	10.6	11.3	12.7	12.7	13.6	15.4	82.50
TEVA	PARADISE	2	1378	ST	COL		591.0	38.0	40.6	42.9	45.8	47.4	51.8	50.7	56.7	64.2	82.39
TEVA	CUMBERLAND	1	3399	ST	COL		1247.0	77.9	82.5	87.2	93.4	100.1	111.1	112.6	120.4	134.4	81.94
TEVA	PARADISE	1	1378	ST	COL		591.0	38.5	40.4	42.7	45.2	49.3	50.5	52.4	54.8	61.9	81.91
TEVA	CUMBERLAND	2	3399	ST	COL		1247.0	77.4	82.3	87.1	92.4	99.2	109.9	111.1	119.0	135.5	81.44
TEVA	COLBERT	5	47	ST	COL		467.0	28.6	30.1	31.8	34.2	37.6	42.0	41.2	44.0	49.7	80.73
TEVA	BROWNS FERRY	1	46	NB	UR		1065.0	71.4	74.2	77.4	81.1	81.2	91.1	91.9	96.9	103.5	80.19
TEVA	BROWNS FERRY	2	46	NB	UR		1065.0	69.0	72.6	75.6	79.6	84.7	89.8	92.4	97.0	105.3	79.91
TEVA	WIDOWS CREEK	8	50	ST	COL		471.0	29.3	31.7	33.5	35.8	37.9	38.9	39.1	43.5	48.0	79.67
TEVA	BROWNS FERRY	3	46	NB	UR		1065.0	70.3	71.3	74.5	78.2	84.7	91.1	89.6	94.2	107.0	79.38
TEVA	GALLATIN	4	3403	ST	COL		278.0	9.2	10.0	11.0	12.3	13.7	24.2	25.1	26.4	30.5	64.90
TEVA	GALLATIN	3	3403	ST	COL		278.0	8.7	9.9	11.0	12.3	13.4	24.1	24.8	26.7	29.7	64.23
TEVA	ALLEN-TN	3	3393	ST	COL		248.0	7.6	8.4	9.4	10.5	11.8	21.5	21.7	23.2	26.3	62.99

4.0 Advanced Analytical Capabilities

Market Pricing Under Deregulation. A producer's marginal cost is not equivalent to market-clearing **price,** because price is determined by interactions among many companies within a much larger market area -- such as the entire Eastern Interconnected System. All potential buyers and suppliers affect the purchase and sales opportunities of a company, and its neighbors, and influence the price the company ultimately pays for the electricity.

As deregulation proceeds, different pricing strategies are evolving, and depend on the degree to which wholesale bulk power prices affect overall revenues. If bulk power prices do not affect revenues from jurisdictional ratepayers, a power producer is motivated to make every sale that contributes some incremental revenue above variable costs.

However, if you operate in an environment in which generation is deregulated and your company must live off of what it can hunt down and eat, detailed production simulation models will provide irrelevant information about market prices. To illustrate this point, ponder what would happen if you were to undertake an equivalent detailed production cost analysis of the deregulated airline industry to determine a ticket price for flying one passenger from New York to Chicago. The analysis would first determine the variable cost (fuel and incremental maintenance including a fifth order polynomial representation of fuel efficiency at various speeds) of flying a 100 Kg passenger on American Airlines, United, Continental, USAir etc, and might find that within the constraints of the transmission system (seat availability), the lowest incremental cost of transporting the passenger is $5.63 on an American Airlines 757. Because the airlines actually compete to charge that passenger somewhere between $250 and $1200 for that flight, the insight gained from the detailed production cost analysis is meaningless for price discovery purposes. It is important for each airline to undertake a detailed production cost analysis to understand its operating costs in detail, but such detail will not help it to understand price!

Market Power Analysis. IREMM is a flexible analytical tool, able to address precisely those issues which are bedeviling the electric power industry, environmental groups, and regulators during the transition to a competitive marketplace. For example, the issues of market power and pricing strategies are illustrated in Figures 12(1) and 12(2). Figure 12(1) shows the horizontal market power of Company 'A' when it attempts to reap higher profits by withholding energy from off-system sales until it can get at least the specified target profit margin per MWh.

Merger Benefits. Many benefits can accrue to companies which merge to form larger market players. First, increased efficiencies and lower costs result from the elimination of duplicate services. Another benefit is greater market presence. Increased market presence can manifest itself in several ways; the first is the elimination of one competitor. With one less competitor, the combined, larger company may be able to push prices higher. Figure 12(2) shows the market power consequences of a hypothetical merger between two companies, and the effect on profits and off-system sales resulting from their combined pricing strategy.

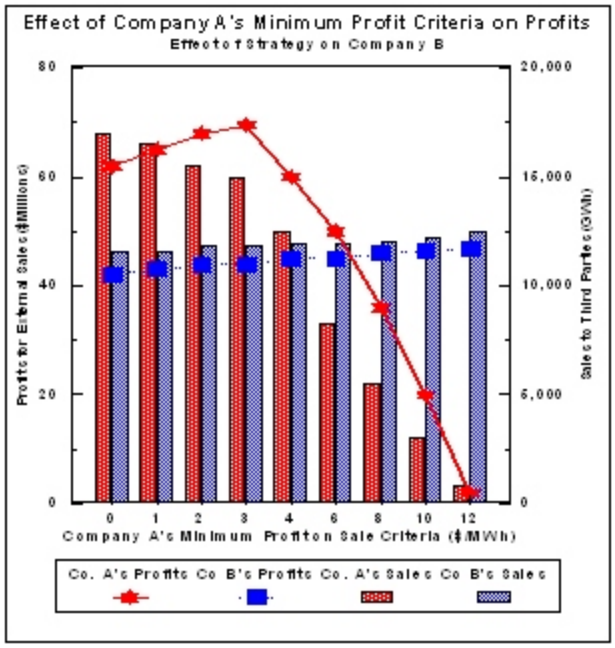

Figure 1

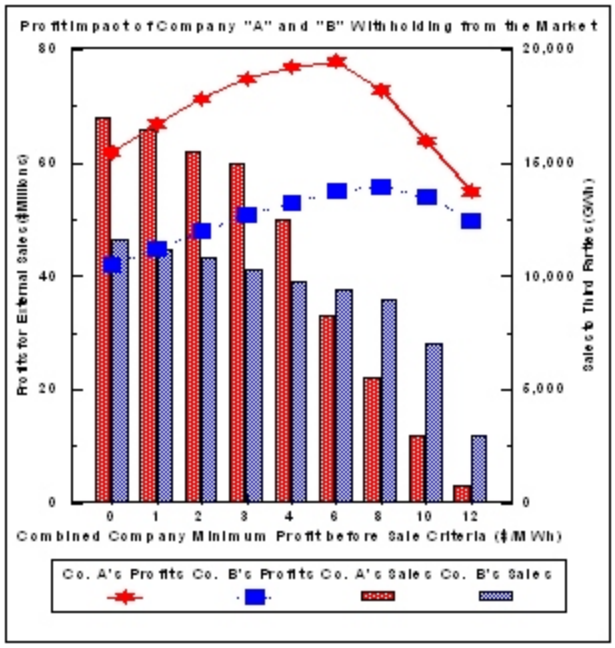

Figure 2

Figure 12: Market Power Analysis.

Transmission Bottlenecks. Transmission interface limits curtail the ability to transfer energy from a region with surplus low cost energy to a region that would benefit from the lower cost energy. Transmission constraints tend to prevent lower cost surplus energy from flowing beyond the seller's side of the interface, and force potential buyers on the other side of the interface to operate their higher cost units. Interface limits result in lower market clearing prices for sellers (lower cost producers) and higher market clearing prices for buyers (higher cost producers). Once an interface limit is reached, the markets on either side become decoupled, and have no further impact on each other.

IREMM incorporates a DC load flow model to provide an understanding of energy flows within a free flowing interconnected system. The output, illustrated in Tables 10 and 11, shows the energy and average MW flows for each load level.

Generation shift factors limit flows across specific transmission links, and enable transmission network information to represent specific transmission constraints realistically. Transactions that violate user-defined constraints are thereby limited.

Table 10: Transmission Constraint Summary

Monthly Load Flows

1997

List of Monitored Elements For Defined Interfaces Element <JAN>

Id	Interface Name	Interface Rating forward	Interface Rating reverse	Load Level Flows (Avg MW) on-peak	Load Level Flows (Avg MW) midpeak	Load Level Flows (Avg MW) offpeak	Monitored Element cirkt	Monitored Element from	Monitored Element to	Guideline Rating (MW)
2	MAAC INTERFACE	2000	-2000							
				9	-158	-286	< 3>	<AEC >	<MAAC>	1000
				-1005	-785	-735	< 13>	<APS >	<MAAC>	1000
				-799	-1036	-964	< 20>	<CAPC>	<MAAC>	1000
				-1795	-1979	-1986				

Table 11: Summary of Line Flows

1997

<JAN> Summary of Line Flows: Positive is out of Market Area or Purchased Energy used for Native Loads
Negative is into a Market Area or Native Generation used for Export

<from>	< to >	rating	Energy Flows (GWh) off-peak	Energy Flows (GWh) mid-peak	Energy Flows (GWh) on-peak	Average Line Flows (MW) off-peak	Average Line Flows (MW) mid-peak	Average Line Flows (MW) on-peak
<AEC >	net market load		8.3	9.1	10.0			
	APS	1000	-251.5	-155.6	-111.3	-1014**	-627	-449
	MAAC	1000	-2.3	39.1	71.0	-9	158	286
	UPNY	1000	245.6	107.4	30.2	990	433	122
<APS >	net market load		-259.9	-197.4	-59.6			
	AEC	1000	251.5	155.6	111.3	1014**	627	449
	AEP	1000	-106.1	-68.1	-131.2	-428	-275	-529
	MAAC	1000	249.2	194.7	182.3	1005**	785	735
	VACR	1000	-185.9	-22.5	-46.1	-750	-91	-186
	CAPC	1000	51.1	-62.2	-56.8	206	-251	-229

Merchant Plants and other Generating Resources. Electricity price forecasts and simulations, such as those IREMM produces, are necessary for any outlook of utility profitability in a competitive environment. The IREMM model is versatile, with many applications. For example, IREMM is often used to study the viability of new merchant plants; and to evaluate existing facilities.

5.0 Qualifications

IREMM, Inc. was founded in 1994 to serve the electric power industry and bulk power market participants. IREMM provides analytical tools to the electric power industry for forecasting the market price of electricity and valuing generating assets, licensing the IREMM model to forward-looking clients. The model is now being used by the staffs of utilities, electric power / gas marketers, and consulting firms for analyzing risks and exploring opportunities in the bulk power market.

6.0 Personnel

Wayne Coste, IREMM's co-founder and principal, is an electrical and electronics engineer with over 20 years of experience in all aspects of electric utility planning. At IREMM, his main responsibility is for the development and enhancement of the IREMM model, which is designed to analyze bulk power markets and to foster improved understanding of the competitive forces underlying the changes in the electric power sector. Mr. Coste frequently is invited to speak about the de-regulating electric power markets at industry and professional organizations. Before founding IREMM, he held positions at the New England Power Pool and Consumers' Power Company, where he was involved in generation planning for large regional power systems. He acquired a knowledge of transmission planning

studies at Gilbert Commonwealth in Jackson, Michigan. He holds a B.S. in Electrical Engineering from the University of Connecticut.

Gail Adams, IREMM's co-founder, holds a Ph.D. in natural resource economics from the University of Massachusetts. She has had extensive experience in the areas of electricity demand and forecasting. Before founding IREMM, she worked at the New England Power Pool in the NEPLAN Load Forecasting section, where she was responsible for the development and implementation of NEPOOL's short-run load forecasting model. Prior to her tenure at NEPOOL, she taught economics, statistics, and mathematical modeling. Dr. Adams has conducted research, published articles, and given presentations on widely ranging topics.

Appendix A: The IREMM Model

1. Introduction

The Inter-Regional Electric Market Model (IREMM) is a unique analytical tool for an increasingly competitive electric power industry. IREMM enables companies to assess the revenue impacts of greater purchase and/or sales opportunities, and to evaluate and manage their power supply portfolio and its attendant risks.

To compete successfully, a company participating in the bulk power market needs to analyze and forecast its competitive position relative to its competitors and/or customers. IREMM can help market participants evaluate their risks and opportunities. The IREMM model is a multi-area production costing model with additional logic to simulate how market participants negotiate prices for electricity when they buy and sell electric power among themselves. The model analyzes competitive forces, explicitly recognizing that sellers attempt to maximize profits by selling at the highest possible price, while buyers simultaneously attempt to maximize savings by purchasing at the lowest possible price. These supply and demand interactions, together with transmission costs, determine regional market prices for electric energy.

The IREMM model is specifically designed to simulate competitive, dynamic electric power markets. Its emphasis on price, as opposed to cost, makes IREMM unique. Traditional utility planning and operations models are cost based and thus incapable of capturing competitive market dynamics. Even the most sophisticated traditional multi-area production costing models typically include only a small portion of the potential market area, and require the user to make static assumptions about purchase and sales opportunities with the outside world. Additionally, these models are unable to analyze the relative market power of buyers and sellers, and assign a proportion of the savings to each company. In contrast, the IREMM model *estimates* the savings and profits received by each company.

All participants within an interconnected electric system comprise the market. IREMM analyzes the impacts of participation in this market, in both the short and long terms, by dynamically modeling the entire region. For example, the market for American Electric Power (AEP) consists of all of the utilities in the Eastern Interconnected System. Many of these utilities may be too far away for AEP to buy or sell energy with directly. However, these remote utilities indirectly influence AEP's market by affecting the purchase and sales opportunities of neighbors they share with AEP. The IREMM model includes such indirect influences upon (in this case) AEP's market in its analysis, and therefore, provides a competitive perspective on the market that traditional modeling tools cannot.

The IREMM model was originally designed as a planning tool to provide a strategic overview of the competitive forces shaping customer/supplier relationships, and is ideal for studying the effects of increasing competition in the bulk power market.

In addition to its long-term analytical capabilities, IREMM is highly competent in short-term applications. IREMM provides clients with files, updated monthly, for producing the *Economy Energy Outlook,* which estimates current electricity prices and a short-term outlook.

2. IREMM Principles

Integral to IREMM's methodology are the following concepts:

1. Market Clearing Prices;
2. Supply and Demand;
3. Incremental Production Costs; and
4. Spot Market Based Capacity Value.

2.1 Market Clearing Prices. The basic premise of the IREMM model is that competitive market forces determine prevailing bulk power prices. Electric companies are paying closer attention to the impact on their revenues from external purchase and sales opportunities. Off-system sales and external purchases can enable an electric company to charge their customers less, thereby enhancing the company's competitive position.

Traditional electric companies have many opportunities for external sales and purchases, but they also must contend with intensifying competition from non-utility generators, power marketers and substitute energy sources (e.g., price induced fuel switching). Thus, today's evolving bulk power marketplace presents risks and opportunities for companies in the electric power sector. Market forces motivate sellers to maximize their selling price, and simultaneously encourage buyers to minimize their purchase price.

2.2 Supply and Demand. The market-clearing price of bulk power is determined by the interaction of supply and demand. IREMM calculates monthly market clearing prices for each market area at three load levels:

1. On-Peak Load Levels;
2. Mid-Peak Load Levels; and
3. Off-Peak Load Levels.

Initially, units are dispatched to meet each individual market area's loads. Once these loads are served from available resources, the surplus energy available for sale and the amount of economically displaceable energy are calculated for various price levels. From these quantities, supply and demand curves for each market area are developed. The interaction of the supply and demand functions, plus the cost of transmitting energy between any two market areas (wheeling costs), determine market-clearing prices. A spatial equilibrium occurs where supply and demand are satisfied simultaneously. Market clearing prices emerge as each of the market areas in the interconnected system attempts to maximize its gains.

The hourly version of the model replaces load duration curves with hourly load data in EEI format. Hourly prices can be forecasted for any period desired, and provide an estimate of price volatility.

2.3 Incremental Production Cost. The surplus and displaceable energy profiles used to develop supply and demand curves are based on incremental production costs. The incremental cost of production is the cost to the generator of producing an additional MWh of energy. To minimize costs, a company must dispatch its lowest cost generating units first. A profit-maximizing company will produce energy as long as its incremental costs of production are less than the additional revenue it receives from the sale of that energy. If it can sell energy externally for more than its incremental cost of production, the company will continue to produce after its own-load needs have been met. On the other hand, if the company can buy the energy needed to meet its load for less than the cost of self-generation, the company maximizes its profits by making the purchase.

The following considerations inform dispatch decisions:

1) incremental costs of producing energy;
2) the delivered cost of any purchased energy; and
3) the selling price (net of wheeling expenses) of energy sold.

To minimize costs, dispatchers operate the lowest incremental cost sources of energy first. A unit's incremental cost of production includes the cost of fuel, the unit's heat rate, the cost of ash disposal, and incremental operation and maintenance costs (e.g. flue gas conditioning, fuel handling and limestone reagent used in scrubbers, the value of Sulfur Dioxide Allowances consumed, etc.). The incremental cost of fuel is represented by the spot price for IREMM's purposes, because contract costs for fuel generally are considered to be sunk.

Market clearing prices for the kWh commodity are not based on fixed or sunk costs, such as fixed operation and maintenance (O & M), or capital investments. Fixed costs are not factored into dispatch decisions; that is, whether to produce the next MWh at a particular unit, from a different unit, or purchase it from another supplier. These costs are incurred whether or not the unit is dispatched and they do not affect the market clearing price. While sellers wish to recover all of their fixed costs - and more if possible - they must settle for as much of a contribution toward fixed costs as the market will allow for a non-firm sale, which may be less than full cost recovery. The spot market energy prices that IREMM calculates for sales include a contribution toward fixed costs for most transactions. No contribution to fixed cost is made only when a company is willing to sell at its variable cost of production, with no minimum profit requirement.

The highest price that a buyer will pay for energy is its own cost of production. Due to competitive market forces, the actual purchase price may be significantly less than the purchaser's costs to self-generate. Realized prices usually will not be related to either the seller's incremental cost to produce the energy, or the buyers cost of the displaced unit.

2.4 Spot Market Based Capacity Value. In the bulk power market, two capacity value attributes can be associated with energy: 1) reliability and 2) locked-in savings:

1. *Reliability value* is the assurance that energy will be available when it is needed to serve future customer loads on the purchasing system at a specific dispatch price. Its economic value arises from the benefits of deferring construction of new capacity; avoiding the need to install load control devices to curtail energy consumption when energy is not available; or retaining customers who would otherwise search for more reliable sources of electric energy.

A contract can be relatively short term (e.g. to cover the outage of a generating unit), or longer lived, lasting many years into the future. The value of the reliability attribute is usually most significant for contracts extending over several years, as these charges enable the purchasing company to defer securing additional generating resources. The value of this component is bounded by the fixed cost of a combustion turbine (e.g. $40.00 - $70.00/kW-year) because this is the type of unit that typically would be installed for reliability purposes.

2. *The locked-in savings attribute* derives from a commitment to purchase energy at prices expected to be below spot prices. This attribute is equivalent to the value of an option to buy a commodity at a specific strike price below the expected market value. A transaction yields economic value to a purchasing company if the strike price is below the expected market clearing price; for example, a strike price equivalent to the cost of production from an "inexpensive" unit. However, the selling company would lose the opportunity to sell from this "inexpensive" unit at higher market clearing prices, and would suffer an economic loss. When the market-clearing price is expected to be above the strike price, the selling company has a strong disincentive to agree to make the contracted sale, unless it receives additional revenue in the form of a demand charge to compensate it for any expected lost opportunity costs associated with committing its capacity.

Many purchase/sales agreements exist between utilities for buying, selling, and transmitting power. Newer agreements are more flexible, and typically include demand charges up to a specified maximum. Consequently, demand charges may be alterable in response to changing market conditions. The parties to a transaction select the contract and associated terms, negotiating the price that most closely approximates their shared perceptions of the market clearing price. The value of this demand charge can be quantified by IREMM for agreements which span months or years.

3. Interpretation of Results

3.1 Transactions. IREMM output shows specific transactions between market areas, and identifies those that are profitable. There are many ways in which the transactions can be effected. In some cases, the exchange is straightforward: two neighboring companies may trade directly with each other at specified prices.

IREMM also identifies transactions that are not so straightforward (e.g. transactions between two market areas separated by several intervening market areas through which power must be wheeled). Intervening companies or power marketers may purchase power for speculation, as well as for their own needs. These companies might then sell the surplus energy purchased to their neighbors. The neighbors may then pass the power along to another neighbor. The result is the same as for a direct sale, but the ultimate transaction is not easily recognizable from historical reports. The companies involved will pursue lucrative transactions in whatever form they can be completed successfully. If unconsummated opportunities between relatively distant companies remain, an independent power marketer or broker could identify it and make the transaction.

3.2 Prices. IREMM's main objective is to determine prevailing equilibrium prices in the bulk power market. On a hot summer day when a number of low variable cost units in a region have been forced out of service, bulk power prices may

exceed those prevailing under comparable load conditions only a few days earlier when those units were in service. The hourly version of IREMM provides a measure of volatility around the prevailing prices.

These situations affect perceptions of price risks, thereby impacting system reliability and security. A highly volatile market might affect perceptions of price risk even in the long term. Attitudes about market instability also may influence the economics of alternative power supply options, and purchasers might be more willing to pay a premium to reduce the risks associated with reliance upon an unstable spot market for energy. Sellers would be motivated to demand a risk premium as part of the price of a transaction to cover potential lost opportunities. The kWh energy commodity price and the risk premium are both set by market forces.

3.3 Transmission Interface Limits. Transmission interface limits curtail energy transfer capability between regions. Transmission constraints tend to prevent lower cost surplus energy from flowing beyond the seller's side of the interface, and force potential buyers on the other side of the interface to operate their higher cost units. Interface limits result in lower market clearing prices for sellers (lower cost producers) and higher market clearing prices for buyers (higher cost producers). Once an interface limit is reached, the markets on either side have no further impact on each other.

3.4 Ancillary Services. The IREMM model examines the economic forces which affect the price and availability of energy as a kWh commodity. In addition to the value of energy as a commodity, a merchant plant or a transaction may provide valuable ancillary service attributes. These additional services include voltage (reactive power) control and reliability of supply (including the maintenance of spinning reserve requirements, attention to spinning reserve distribution throughout the interconnected network, automatic generation control, etc.). For example, full responsibility capacity sales or purchases shift the burden of providing spinning reserve requirements from the buyer to the seller. Factors such as these enhance the value of a transaction beyond the value of the energy purchased or sold, causing prices paid for electricity in the bulk power market to diverge from the commodity price.

An Independent System Operator (ISO) also may provide services to the units in its control area. These services would include: power quality, system security, transmission services, technical support, and coordination with numerous other entities in the integrated power system.

4. Strategic and Policy Analysis.

IREMM is a superior tool for strategic and competitor analysis, fully capable of analyzing the dynamics of the energy market. The IREMM model provides a global view of the challenges confronting the electric power industry.

4.1 Scenario Analysis. IREMM furnishes a unique analytical framework for analyzing the impacts of changes in various exogenous factors affecting bulk power markets. Since IREMM includes detailed generating unit-specific information for all participants in the bulk power market, it can be used to study the impacts of changes in exogenous variables on the entire market area simultaneously. For example, changes in the following factors are among those which can be analyzed using IREMM:

- relative fuel prices;
- customer loads;
- unit availability;
- unit additions and retirements;
- aggressiveness of sellers (willing to sell on smaller profits);
- aggressiveness of buyers (willing to buy on smaller savings);
- wheeling costs; and
- retail wheeling for traditional utility customers.

Insights gained through IREMM may be input into more detailed simulation and systems models, such as Power Technologies, Inc. load flow and stability models. The more detailed simulation models could then be used to quantify other network services, such as spinning reserve, voltage control, system security, and risk premiums for firm power.

The principle IREMM outputs are prices and quantities, and they may be used to identify likely suppliers and purchasers of economic energy. IREMM's ability to quantify trends in energy prices provides strategic insight into the economics of future resource additions and/or potential retirements.

4.2 Identifying Market Opportunities. IREMM can help new entrants absorb and assimilate many aspects of the bulk power marketplace, because many competing and complex factors are summarized in terms of prices and quantities. Analysis of these two attributes can help identify the most likely prospects for brokered transactions. To identify buyers and sellers, the utilization patterns of high and low cost generating resources throughout several regions must be understood and forecasted simultaneously.

IREMM's databases are easy to update, and the model runs quickly on most computer platforms. It is possible to analyze specific scenarios rapidly and to identify the transactions that could be effected. For example, an IREMM base case can be updated whenever new information about the market becomes available, such as "Browns Ferry is now forced out of service for the next 5 to 6 months," or "natural gas prices are expected to soar for several months." These changes create market opportunities that participants are better positioned to exploit if they have insights into current and future market conditions. IREMM is a powerful tool that simulates the market forces that create such opportunities. IREMM helps participants anticipate the market's response to events in a timely manner.

4.3 Stranded Investment. IREMM can help determine the extent to which existing units would remain economically viable in a competitive environment, and to quantify the amount of stranded investment resulting from open access. The following key parameters provide information needed to determine which competing units would be likely candidates for retirement:

1. The market clearing price for energy ($/MWh);
2. The market price for capacity (value of the right to take energy) ($/kW-yr);
3. Variable costs from a unit (fuel and incremental O&M cost) ($/MWh), and;
4. Fixed O&M costs for a unit ($/yr).

Using these parameters, competing units can be ranked according to their contribution to fixed expenses, as shown below:

Contribution($/yr) = Reliability Value * Rating + [Market Clearing Price - Fuel Cost - Incremental O&M] * MWh sold - Fixed O&M

Ranking the contribution to fixed expenses in $/yr reveals which units contribute the most to fixed expenses in absolute dollar terms. Alternatively, the units could be ranked independent of their size.

The fixed O&M component is applicable in longer term studies, such as analysis of a generating unit's economic viability. In the long run, fixed O&M expenses become variable costs that can be avoided by retiring or mothballing the unit. In a shorter term analysis, fixed O&M expenses are not included because the decision to dispatch a unit for an external sale is based on whether the sale is profitable and contributes toward fixed expenses (O&M and capital investment) after covering fuel and other incremental variable O&M costs.

The fixed capital cost of an existing unit is not included in either a long or short term analysis of existing units, since these expenses will be incurred whether the unit remains in service or is retired. Capital costs should be considered only when analyzing the potential return on investment of future resource additions.

Appendix B: IREMM Reports

Report No.	Report Title	Report Description
	INPUT SUMMARY	
01	Input Fuel Price Summary	Three reports document escalated fuel price and regional basis differentials.
02	Wheeling Cost Matrix	Shows the wheeling costs between market areas.
03	Load, Capability and Reserve Margins	Documents summer / winter loads, capacities, and reserve margins.
04	Extrapolated / Adjusted Peak Load and Energy Forecasts	Documents the summer/winter peak loads and annual GWh actually used in the analysis beyond the years covered by the input data.
05	Regional Fuel Switching Strategies	Describes broad brush fuel switching strategy options for the year 2000.
06	System Interfaces Defined	Lists companies on either side of a defined interface.
09	Least Cost Wheeling Path Between Market Areas	Optional report; printed if the **COMPRATE** parameter is set. Shows the companies on the least cost path between any two market areas.
	STUDY SUMMARY OUTPUT REPORTS	
10	Study Summary of Each Market Area's Clearing Prices	Bid and ask prices by market area for each load level and month of the study period.
11	Study Summary of Demand Charges at Selected Strike Prices	Shows up-front demand charges at specified strike or dispatch prices. Controlled by **STRIKE** parameter in the **<cntrl>** file.
12	Study Summary of Annual GWh Sales - *Showing Their Customers*	Shows sellers, their customers, and the amount of energy sold in each year.
13	Study Summary of Annual GWh Purchases - *Showing Their Suppliers*	Shows buyers, their suppliers, and the amount of energy purchased in each year.
14	IREMM Competitive Indices	Summarizes contributions to fixed costs, calculates the IREMM competitive index and sales/purchase statistics. Report No. 19 may need to be requested for a complete analysis.
15	Study Summary of Savings, Profits and Production Costs and Associated Energy Accounting	Summarizes dispatch costs before and after transactions, and associated profits on sales or savings on purchases. The energy associated with these transactions are also shown.
16	Study Summary of Fuel and Variable O&M by Unit	Summarizes production costs by unit after transactions.
17	Study Summary of GWh Production by Unit	Summarizes annual energy production by unit after transactions.
18	Study Summary Contributions to Fixed Costs by Company	Summarizes contributions to fixed costs by operating company. Defined when **COLLAPSE** is zero in the **<cntrl>** file.
19	Study Summary Contributions to Fixed Costs by Unit	Summarizes contributions to fixed costs by unit and summed for each market area.
58	Study Summary of Net Contributions after O&M and Capacity Value by Unit	Shows contributions to fixed costs by unit, after subtracting O&M costs and adding a capacity value
	ANNUAL SUMMARY OUTPUT REPORTS	
20	Market Area Prices, "Gains" and Transactions by Load Level	Detail of market area transactions, includes bid and ask prices and amount of energy transacted, by month and load level.
21	Unit Dispatch - *Before Transactions*	Monthly summary of energy production before transactions (with cost accounting), for requested market areas.
22	Transaction Induced Changes to Unit Dispatch	Monthly summary of changes in energy production induced by transactions (with cost accounting) for requested market areas.
23	Unit Dispatch - *After Transactions*	Monthly summary of energy production after transactions (with cost accounting), for requested market areas.
24	Annual Summary of Monthly GWh Sales - *Showing Their Customers*	Monthly summary of energy sold by market area, identifying the customers.
25	Annual Summary of Monthly GWh Purchases - *Showing Their Suppliers*	Monthly summary of energy purchased by market area, identifying the suppliers.

Report No.	Report Title	Report Description
26	GWh Transfers Between Market areas - *Annual Summary*	Annual summary of energy sold from one market area to another. Presented in matrix format.
27	Annual Wheeling Expenses for Transfers Between Market areas	Annual summary of third-party wheeling expenses. Presented in matrix format.
28	Technology Utilization - *Before Transaction*	Annual summary of the technologies used before transactions for the first 19 technology types.
29	Technology Utilization - *After Transactions*	Annual summary of the technologies used after transactions for the first 19 technology types.
30	State Level Energy Production by Fuel Type - *After Transactions*	Monthly state level summary of energy production in TWh, by fuel category.
31	Total State Fuel Utilization - *After Transactions*	Monthly summary of fuel use by category, in Trillion Btus for each state.
32	Total Market Area Level Fuel Utilization - *After Transactions*	Monthly summary of fuel use by category, in Trillion Btus for each market area.
33	Summary of Emissions and Fuel Consumption in Quads	Six reports summarizing SO_2, NO_X, and CO_2 emissions, and fuel consumption in Quadrillion Btus before and after transactions.
34	Monthly Economy Energy Index by Month	Summary of market clearing prices, with certain adjustments.
35	Monthly Economy Energy Index by Month	Same as report 34, but includes the names of the market areas.
36	Energy Flows Across Transmission Interfaces	Shows monthly energy transfers across interfaces defined in Report No. 06.
37	Annual Summary of Contributions to Fixed Costs	Annual summary by unit, providing the basis for Report No. 19.
38	Monthly Demand Charges	Development of demand charge by month for all market areas.
39	Market Power Analysis Reports	Analysis of HHI and other market power indices (currently under development).
40	Plant Level Summary of Generation by Technology Type	Summarizes generation by technology at each plant
41	Sub-Region Generation by Fuel and Technology Type	Provides regional statistics by technology and fuel type.
42	Unit Level Financial Pro-Forma Summary	Provides unit level financial pro-formfrom operations showing revenues and costs for each unit
MODELING DETAIL ANNUAL REPORTS		
50	Adjusted Monthly Load Profile For Peak and Energy	Documents monthly load profiles used in the simulations for all market areas.
51	Annual Update of Master Record Unit Capacity	Summary of changes in capacity ratings for each year of the study, for all units with changes.
52	Monthly Changes to Capacity from Rating Changes	Capacity changes and unit derates, for all units with changes.
53	Monthly Unit Ratings	Report of unit ratings used in each month, before maintenance.
54	Unit Capacity Scheduled Out For Maintenance	Monthly maintenance schedules, for all units in requested market areas.
55	Market Area Capacity Scheduled Out for Maintenance	Summary of total maintenance by market area.
56	Maintenance Schedule	Formatted maintenance schedule used in **<maint>** input file.
57	Planning Reserve Margin Based Resource Additions.	Documents new capacity automatically added to a "Planning Reserve Group" based on the **RESGROUP** parameter.
58	Auto Retirement of Units Not Covering Total Cash O&M	Shows details of the auto-retirement logic.
59	Auto Retirement and Expansion Unit Change Records	Creates a file that can be read back in which would contain all of the automatic unit retirements as well as expansion units needed to maintain reserve margin targets.
MODELING DETAIL MONTHLY REPORTS		
60	Monthly Update to the Unit Master Records	Changes by unit in primary and alternate fuels, SO_2 scrubber efficiencies, technology type, heat rate, EAFs and EFORs.

Report No.	Report Title	Report Description
61	Calculation of Dispatch Costs	Shows assumptions used to calculate unit dispatch costs, by month, for requested market areas. Debug report 20 provides price detail — see **YEAR** parameter in the **<cntrl>** file.
62	Monthly Load Curve and Capacity Parameters	Shows dispatch parameters for various categories of capacity, and adjusted loads after modifications.
63	GWh Transfers Between Systems - *Monthly Summary*	Monthly summary of energy sold from one market area to another. Presented in matrix format.
64	Load Curve Impact of Hydro, Pumped Storage and Transactions	Monthly summary of capacity and energy adjustments.
65	Network Load Flows	When the **LOADFLOW** parameter is specified in the **<cntrl>** file, a network analysis is performed, and the resulting energy flows on each transmission link and each interface are presented.
66	Interface Constraints Summary	Summarizes the remaining transfer capability between market areas, to help analyze which interfaces constrain flows.
67	Monthly Emissions and Monthly Contributions to Fixed Costs	Provides monthly details of SO_2,CO_2 and NOx emissions as well as monthly details of the contributions to fixed costs.
	MODELING DETAIL LOAD LEVEL REPORTS	
70	Unit Dispatch Detailed Parameters	Shows cryptic information about unit dispatches for each load level, for each unit, for requested market areas.
71	Development of Load Level Supply and Demand Curves	Shows cumulative amount of energy available for sale or displacement, by month and load level, for requested market areas.
72	Load Level Supply and Demand Curves - *Before Transactions*	Shows the amount of energy available for sale or purchase at each price level before transactions, by month and load level.
73	Load Level Supply and Demand Curves - *After Transactions*	Shows the amount of energy available for sale or purchase at each price level after transactions, by month and load level.
74	GWh Transfers Between Market areas - *Load Level Detail*	Load level summary of energy sold from one market are to another. Presented in matrix format.
75	Unit Level Profit and Savings Contribution - *Load Level Detail*	Shows profits and savings from transactions at each load level, by unit for requested market areas.
76	Market Area Summary of Profit and Savings - *Load Level Detail*	Report showing profits and savings from transactions at each load level for requested market areas.
77	Unit Dispatches and Showing Effect of Transactions - *Load Level Detail*	Monthly report showing unit dispatch before and after transactions, for requested market areas.
78	Global Supply and Demand Curves for all Market Areas - *Load Level Detail*	Shows global supply and demand curves by month, for each load level. Can be used with SUP_DMD.WK4 to display supply and demand curves for all market areas for each month.
79	Operating Reserve Group Summary Information	Shows the detail for each operating reserve group for each hour including the target amounts of spinning and quick start reserves and the amounts obtained.
	HOURLY RESULTS OUTPUT REPORTS	
80	Hourly Load Adjustments for Each Market Area	Documents adjustments for each market area.
81	Hourly Bid Prices	Presents hourly bid prices for requested market areas.
82	Hourly Ask Prices	Presents hourly ask prices for requested market areas.
83	Hourly Interface Flows	Shows hourly flows across defined interfaces.
84	Hourly Fuel Consumption by Category	Summarizes hourly fuel consumption, by fuel category by market area.
85	Hourly Market Price (Bid or Ask as Appropriate)	Presents the price that are most characteristic for the market area (Bid prices when buying and ask prices when selling.
86	Hourly Purchase and Sales Summary	Provides hourly detail of how much a market area is purchasing or selling in each hour.
87	Daily LOLE by Operating Group	Provides daily summaries of LOLE for each operating group

Report No.	Report Title	Report Description
88	Hourly LOLE-based Capacity Value by Operating Group	This provides one view of capacity valuation using an hourly LOLE calculation and an operating reserve group value-of lost-load
90	Monthly Hourly Price Statistics and Distributions	Provides monthly statistics by load level and for all hours describing the means, standard deviations, ranges and histogram data
91	Condensed Hourly Price Statistics	Provides monthly statistics by load level as well as for all hours describing the means, standard deviations, and ranges in a more accessible format than Report No. 90
92	Condensed Interface Flow Statistics	Provides monthly statistics by load level as well as for all hours describing the means, standard deviations, and ranges in a more accessible format than Report No. 83
93		
95	Hourly Unit Specific Generation and Contributions to Fixed Costs	Enables unit specific generation to be analyzed on an hourly basis.
96	Hourly Capacity Margin Statistics by Market Area	For each market area, the market price and hourly reserve data is presented to allow price vs. reserve to be analyzed.
97	Summary of Weekly Load Level Unit Dispatch and Loads	Provides weekly summaries of operable capacity and reserves for export to risk management modules
98	Development of Cost Curves	Provides details of unit dispatch “stack” whenever there are changes in resource maintenance or cost characteristics.
99	Summary Database File - *CLRFILE.OUT*	The Extract program **QUERY** reads the output and provides a summary of key information in a .prn file. These data may be imported into an ACCESS database or read by a spreadsheet.

Appendix C: The IREMM for Windows Environment

Figure C-1 shows a scenario file opened in the IREMM for Windows 95/NT environment. The left side shows the cases that will be run by the scenario manager, and the right side displays elements of the base case. These elements are the input files, and the path and file names for the output.

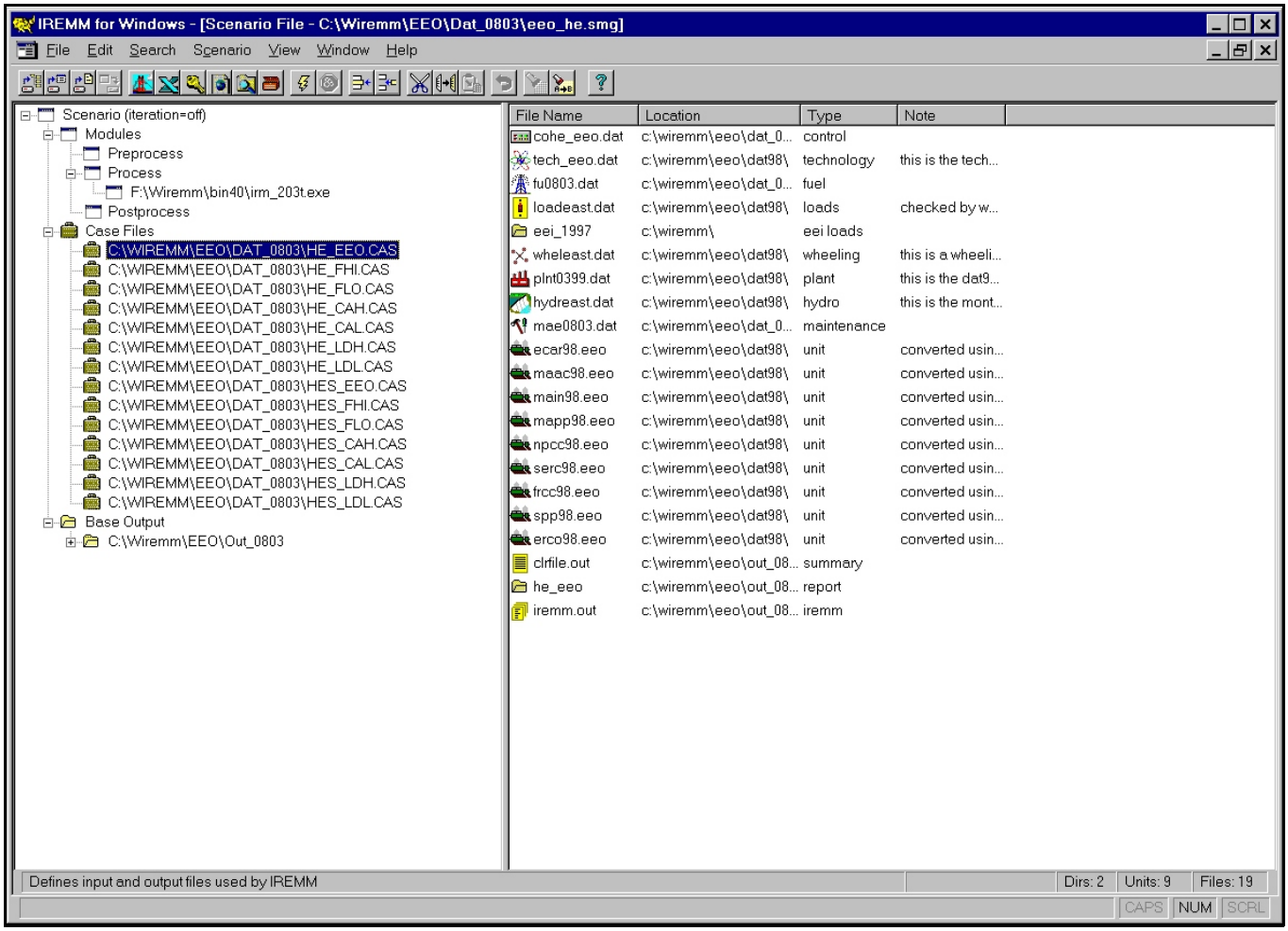

Figure C-1: The IREMM for Windows Environment, with Scenario Manager Open.

IREMM provides many programs for post-processing the data, and spreadsheet templates for ease of analysis. Figure C-2 shows the Utilities window, with tabs for programs for processing the results. These auxiliary programs can also be specified in the Scenario Manager window under "Postprocess."

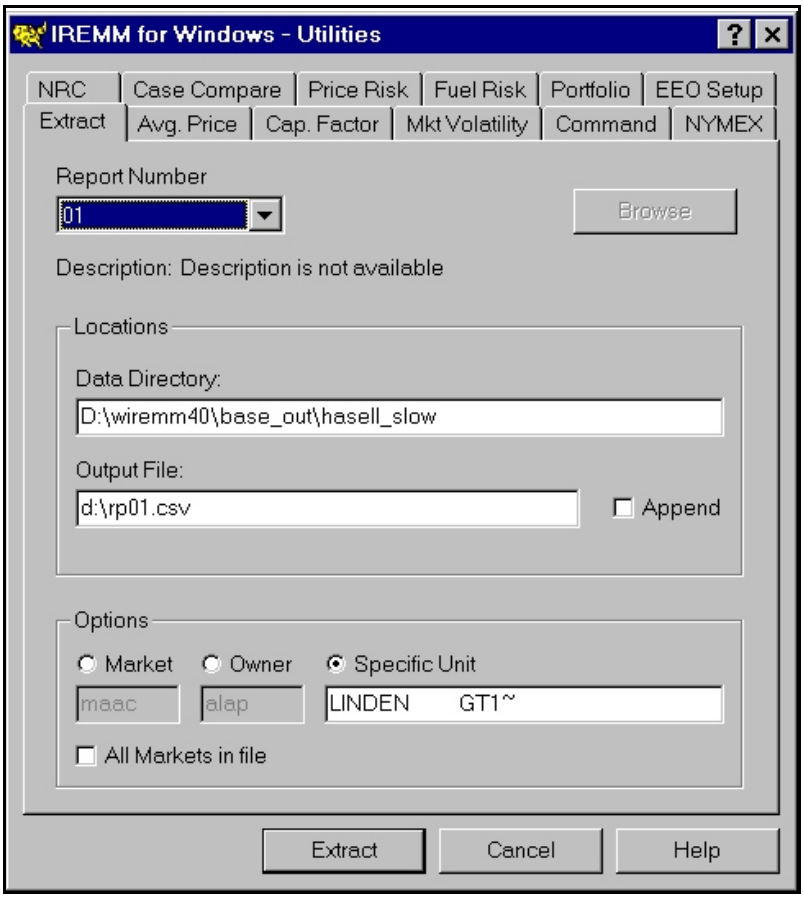

Figure C-2: The Toolbox Tab

The MS Access database that is used to interface with the IREMM Model provides flexibility for updating the data and simplify the interface with the Model. Figure C-3 shows the conceptual data relationships and this opening screen allow direct access to each of the forms for editing and displaying data elements.

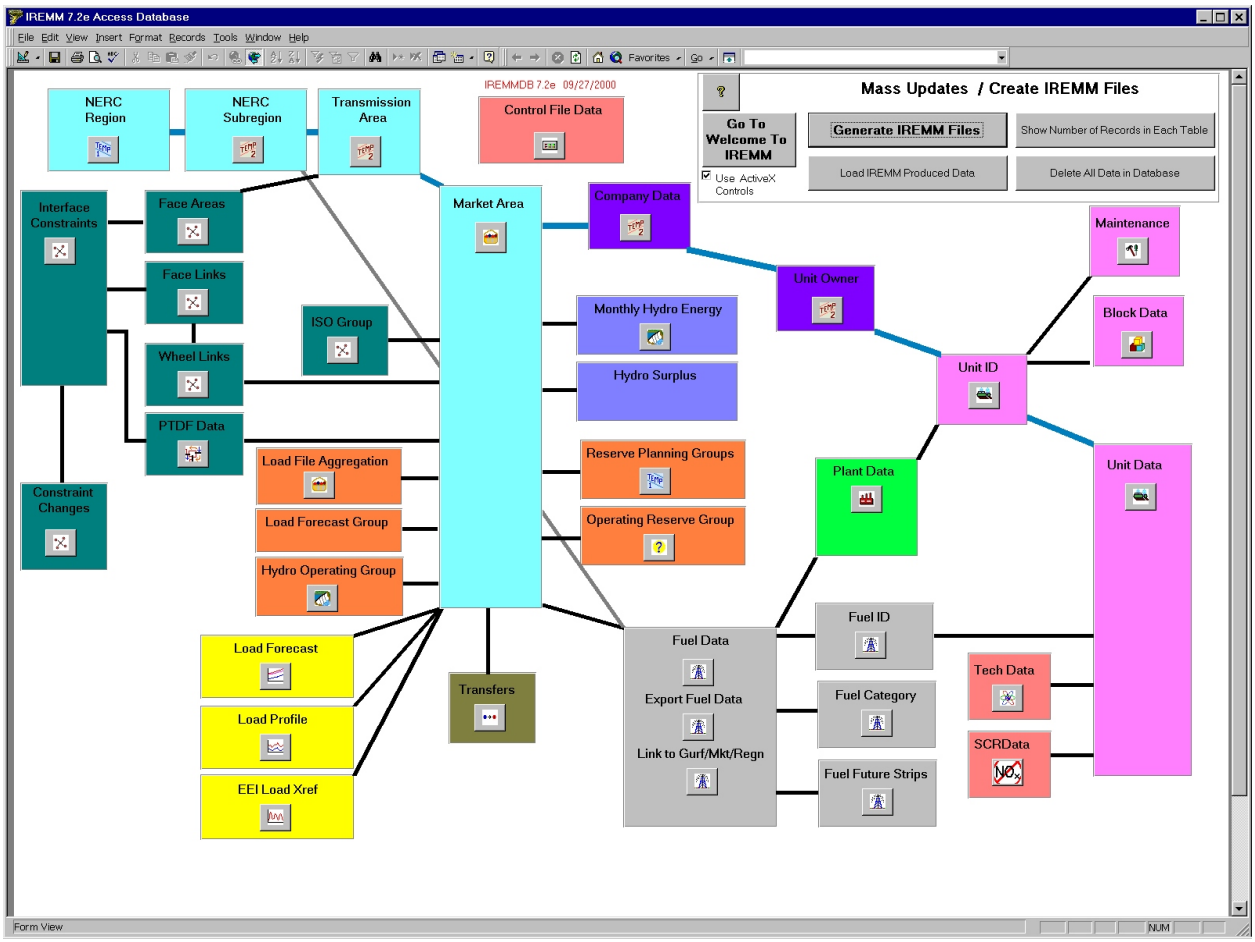

Figure C-3: Schematic of Data Relationships used in the IREMM Database

Appendix D: Sample Output Reports

Report No. 16: Study Summary of Fuel and Variable O&M by Unit

Report No. 16 provides a summary of production costs, by unit after transactions. The difference between these costs, and the revenues from selling both on the bulk power market and to native customers, determines a unit's contribution to fixed costs. Data from this report can be extracted using the **CQXX.EXE** program.

The market areas printed in this report are selected by the **PRINT** or **PRINTALL** parameters in the **<cntrl>** file.

Report No. 16 is directed to the file: **<rp16.rpt>** in the directory defined by **<repor>**.

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 Inter-Regional Electric Market Model (IREMM) Release1.16a(c) IREMM, Inc. 1995, Licensed: IREMMto 12/31/97  Report #16    Page   323
 Case Title:   THIS IS THE BASE CASE FOR TESTING THE 1996 HVPL DATA                          <BASEHVPL>   Tue Sep 30 17:47:01 1997
           Study Summary of Fuel and Variable O&M by Unit


               Summary of Unit Specific Fuel and Variable O&M <HVPL> shown in ($Million)

                                    Fuel-Type Max Cap                                                                          Annual Avg.
Comp Unit Name             Plant Tech  Pri  Sec  (Sum MW) 1997   1998   1999   2000   2001   2002   2003   2004   2005   2006   2007   2008   2009   2010    ($/kw-yr)
---- -------------------- ----- ----- ---- ---- -------- ------ ------ ------ ------ ------ ------ ------ ------ ------ ------ ------ ------ ------ ------ -----------
HVPL CANTON           2      942 STC5  COL  NG       506   51.5   51.0   51.2   49.7   49.9   50.0   50.1   50.3   50.4   50.6   50.8   50.9   51.1   51.3       37.17
HVPL HARTLAND         9      941 CC    NG   FO6      130      .      .   12.7   14.2   14.6   15.5   15.5   15.5   13.7   13.7   13.7   13.7   13.7   14.0       34.67
HVPL VALLEY           2      943 STC2  COL             110   12.0   12.4   12.4   12.8   12.9   12.9   12.9   13.0   13.0   13.1   13.1   13.1   13.2      .       32.95
HVPL VALLEY           1      943 STC2  COL             110   12.1   12.5   12.4   12.8   12.9   12.9   13.0   13.0   13.0   13.1   13.1   13.1   13.2      .       30.29
UNKN EXPANSION UNITS TCH1      0 CCN   NG               70      .    1.3    1.3    1.3    1.8    4.2    4.2    4.2    3.6    4.0    4.0    4.6    4.6    4.6       28.99
HVPL CANTON           1      942 STC3  COL             212   12.5   19.6   20.3   21.9   23.1   23.2   23.7   24.6   24.8   21.9   24.5   24.3   22.6   24.7       27.02
HVPL VALLEY           4      943 ZZ    FO2  NG         350   13.1   17.9   17.5   18.9   24.2   29.5   30.2   30.9   30.1   26.2   29.6   26.5   28.6      .       18.22
UNKN AGGR. CONV HYDRO          0 HY    WAT             132      .      .      .      .      .      .      .      .      .      .      .      .      .       17.54
HVPL HARTLAND         6      941 STG3  NGFX FO6        200    1.6    5.2    8.0    8.9   11.0   10.5   11.0   11.1   14.4   11.9   12.6   13.1   12.5      .       14.68
UNKN EXPANSION UNITS TCH2      0 GTN   NG               70      .    0.3    0.4    0.5    0.8    2.0    1.9    2.1    4.9    4.8    4.9    5.5    5.5    5.8        8.94
UNKN AGGR. PUMPED STORAGE      0 PS    WAT             150      .      .      .      .      .      .      .      .      .      .      .      .      .      .        1.95
HVPL VALLEY           3      943 STO4  FO6             350      .    0.0      .    0.0      .      .      .      .      .      .      .      .      .      .        0.00
HVPL CANTON           2      942 STC5  COL  NG           8      .      .      .      .      .      .      .      .      .      .      .      .      .      .        .
HVPL GRANBY           C      944 GT    NG*              44      .      .      .      .      .      .      .      .      .      .      .      .      .      .        .
HVPL HARTLAND         7      941 STO2  FO6             170      .      .      .      .      .      .      .      .      .      .      .      .      .      .        .
HVPL HARTLAND         8      941 STO2  FO6             170      .      .      .      .      .      .      .      .      .      .      .      .      .      .        .
HVPL GRANBY           D      944 GT    NG*              44      .      .    0.0      .      .      .      .      .      .      .      .      .      .      .        0.00
UNKN EMERGENCY UNIT            0 GT    NG*            1146      .      .      .      .      .    0.0    0.0    0.0      .      .    0.0    0.0    0.0    0.0        0.00
HVPL GRANBY           B      944 GT    NG*  FO2         44    2.9      .      .      .      .      .      .      .      .      .      .      .      .      .       -2.54
HVPL GRANBY           A      944 GT    FO2  NG*         44    7.6      .      .      .      .      .      .      .      .      .      .      .      .      .       -6.31
                                                                ------ ------ ------ ------ ------ ------ ------ ------ ------ ------ ------ ------ ------ ------ -----------
     <HVPL> Total System Generation  ($Million)            113(a) 120    136    141    151    161    163    165    168    159    166    165    165    100-       2074


The annual average energy is based on the sum of the dollar contributions
    divided by the number of years and the maximum capacity during the study period.
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Note: (a) Matches Report No. 23.

Report No. 17: Study Summary of GWh Production by Unit

Report No. 17 is a study summary of annual energy production by unit after transactions.

The market areas printed in this report are selected by the **PRINT** or **PRINTALL** parameters in the **<cntrl>** file.

Data from this report can be extracted using the **CQXX.EXE** program.

Report No. 17 is directed to the file: **<rp17.rpt>** in the directory defined by **<repor>**.

Inter-Regional Electric Market Model (IREMM) Release1.16a(c) IREMM, Inc. 1995, Licensed: IREMMto 12/31/97 Report #17 Page 318
Case Title: THIS IS THE BASE CASE FOR TESTING THE 1996 HVPL DATA <BASEHVPL> Tue Sep 30 17:47:01 1997
Study Summary of GWh Production by Unit

Summary of Unit Energy Production in GWh <HVPL>

Comp	Unit Name		Plant	Tech	Fuel-Type Pri	Fuel-Type Sec	Max Cap (Sum MW)	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Annual Avg. ($/kw-yr)
HVPL	CANTON	2	942	STC5	COL	NG	506	3549.0	3505.9	3505.9	3492.1	3492.1	3492.1	3492.1	3492.1	3492.1	3492.1	3492.1	3492.1	3492.1	3492.1	37.17
HVPL	HARTLAND	9	941	CC	NG	FO6	130	.	.	780.6	862.5	880.2	926.0	927.9	928.1	1008.6	1008.6	1008.6	1008.6	1008.6	1016.2	34.67
HVPL	VALLEY	2	943	STC2	COL		110	814.4	837.9	837.9	837.9	838.5	838.5	837.9	838.5	838.5	838.5	838.5	838.5	838.5	.	32.95
HVPL	VALLEY	1	943	STC2	COL		110	816.7	843.2	837.9	837.9	837.9	837.9	843.2	837.9	837.9	837.9	837.9	837.9	837.9	.	30.29
UNKN	EXPANSION UNITS TCH1		0	CCN	NG		70	.	96.5	96.5	96.5	127.9	300.7	300.7	300.7	320.6	358.1	358.1	408.2	408.2	408.2	28.99
HVPL	CANTON	1	942	STC3	COL		212	746.4	1196.7	1238.4	1335.5	1402.5	1406.4	1430.9	1481.3	1494.5	1314.5	1465.0	1450.7	1344.2	1467.9	27.02
HVPL	VALLEY	4	943	ZZ	FO2	NG	350	749.0	976.7	946.9	1027.1	1308.5	1599.5	1641.3	1683.5	1637.3	1440.0	1612.4	1453.3	1573.3	.	18.22
UNKN	AGGR. CONV HYDRO		0	HY	WAT		132	404.7	404.7	404.7	404.7	.	.	.	.	.	.	.	.	.	.	17.54
HVPL	HARTLAND	6	941	STG3	NGFX	FO6	200	92.9	274.7	405.8	452.2	552.4	529.1	553.6	558.0	778.0	643.7	680.2	704.1	674.2	.	14.68
UNKN	EXPANSION UNITS TCH2		0	GTN	NG		70	.	16.2	20.3	22.3	39.0	95.3	91.8	97.6	283.7	284.1	286.5	317.6	317.6	329.2	8.94
UNKN	AGGR. PUMPED STORAGE		0	PS	WAT		150	-49.3	-49.3	-49.3	-49.3	.	.	.	.	.	.	.	.	.	.	1.95
HVPL	VALLEY	3	943	STO4	FO6		350	.	0.0	.	0.0	.	.	.	.	.	.	.	.	.	.	0.00
HVPL	CANTON	2	942	STC5	COL	NG	8	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
HVPL	GRANBY	C	944	GT	NG*		44	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
HVPL	HARTLAND	7	941	STO2	FO6		170	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
HVPL	HARTLAND	8	941	STO2	FO6		170	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
HVPL	GRANBY	D	944	GT	NG*		44	.	.	0.0	.	.	.	.	.	.	.	.	.	.	.	0.00
UNKN	EMERGENCY UNIT		0	GT	NG*		1146	.	.	.	.	.	0.0	.	.	.	.	0.0	0.1	0.1	0.1	0.00
HVPL	GRANBY	B	944	GT	NG*	FO2	44	70.3	.	.	.	.	.	.	.	.	.	.	.	.	.	-2.54
HVPL	GRANBY	A	944	GT	FO2	NG*	44	211.2	.	.	.	.	.	.	.	.	.	.	.	.	.	-6.31
<HVPL> Total System Generation (GWh)								**7405(a)**	8103	9026	9319	9479	10026	10119	10218	10691	10218	10579	10511	10495	6714-	132903

The annual average energy is based on the sum of the dollar contributions
divided by the number of years and the maximum capacity during the study period.

Note: (a) Matches Reports No. 15h, No. 23 and No. 37.

Report No. 19: Study Summary Contributions to Fixed Costs by Unit

Report No. 19 shows the contributions to fixed costs by unit. The contribution per MWh is the difference between the market clearing price and the dispatch cost of the unit. Each MWh of energy generated is credited with this profit (or contribution to fixed costs), regardless of whether the energy is targeted to serve a market area's own load needs or is sold to another market area. Contributions to fixed costs by owner (for units with multiple owners) may be obtained by setting the **COLLAPSE** option in the **<cntrl>** file to zero.

The market price used in these calculations is the higher of the bid and ask price in a load level, unless the **CONT2FIX** parameter is specified in the **<cntrl>** file. The dispatch costs (fuel and variable O&M) are subtracted from this price to obtain the contribution to fixed costs. Contributions to fixed costs per MWh are calculated separately for each load level.

For pumped storage units, contributions to fixed costs is the on-peak value using the higher of the bid and ask prices, minus the cost of the pumping energy. Pumping costs are based on the lower of the bid or ask prices during the off- and mid-peak periods.

The market areas printed in this report are selected by the **PRINT** or **PRINTALL** parameters in the **<cntrl>** file. Data in this report can be extracted using the **CQXX.EXE** program.

Report No. 19 is directed to the file: **<rp19.rpt>** in the directory defined by **<repor>**.

Inter-Regional Electric Market Model (IREMM) Release1.16a(c) IREMM, Inc. 1995, Licensed: IREMMto 12/31/97 Report #19 Page 183
Case Title: THIS IS THE BASE CASE FOR TESTING THE 1996 HVPL DATA <BASEHVPL> Tue Sep 30 17:47:01 1997
Study Summary of Contribution to Fixed Costs- Company

Contributions to Fixed Cost in $Million For <HVPL>

Comp	Unit Name	Plant	Tech	Fuel-Type Pri	Fuel-Type Sec	Max Cap (Sum MW)	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Annual Avg. ($/kw-yr)
HVPL	CANTON	2	942 STC5	COL	NG	506.0	10.8	15.2	16.3	20.3	22.1	23.1	23.7	25.5	23.2	15.4	17.2	16.1	15.6	18.9	37.17
HVPL	HARTLAND	9	941 CC	NG	FO6	130.0	.	.	3.4	4.0	4.4	4.5	4.7	5.2	7.8	5.4	6.0	5.7	5.5	6.6	34.67
HVPL	VALLEY	2	943 STC2	COL		110.0	2.3	3.6	3.6	3.8	4.8	5.0	4.8	5.6	5.0	2.9	3.4	3.1	2.9	.	32.95
HVPL	VALLEY	1	943 STC2	COL		110.0	2.3	3.5	3.6	3.8	4.2	4.4	4.7	4.9	4.3	2.6	3.1	2.7	2.6	.	30.29
UNKN	EXPANSION UNITS TCH1	0	CCN	NG		69.6	.	0.51	0.55	0.62	0.89	2.2	2.2	2.4	3.2	2.7	3.0	3.2	3.2	3.6	28.99
HVPL	CANTON	1	942 STC3	COL		212.0	2.2	5.0	5.6	6.7	7.2	7.5	7.9	8.6	7.4	3.9	4.8	4.2	3.8	5.4	27.02
HVPL	VALLEY	4	943 ZZ	FO2	NG	350.0	1.7	6.1	6.6	8.2	9.2	9.4	10.0	11.6	9.4	3.9	4.9	4.4	3.9	.	18.22
UNKN	AGGR. CONV HYDRO	0	HY	WAT		132.0	7.3	8.1	8.3	8.7	.	.	.	.	.	.	.	.	.	.	17.54
HVPL	HARTLAND	6	941 STG3	NGFX	FO6	200.0	0.59	1.8	2.8	3.5	4.2	4.1	4.2	4.8	5.2	2.2	3.1	2.4	2.2	.	14.68
UNKN	EXPANSION UNITS TCH2	0	GTN	NG		69.6	.	0.10	0.16	0.20	0.32	0.71	0.74	0.85	1.3	0.71	0.88	0.86	0.76	1.1	8.94
UNKN	AGGR. PUMPED STORAGE	0	PS	WAT		150.0	0.19	1.1	1.3	1.5	.	.	.	.	.	.	.	.	.	.	1.95
HVPL	VALLEY	3	943 STO4	FO6		350.0	.	0.00	.	0.00	.	.	.	.	.	.	.	.	.	.	0.00
HVPL	CANTON	2	942 STC5	COL	NG	8.0	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
HVPL	GRANBY	C	944 GT	NG*		44.0	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
HVPL	HARTLAND	7	941 STO2	FO6		170.0	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
HVPL	HARTLAND	8	941 STO2	FO6		170.0	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
HVPL	GRANBY	D	944 GT	NG*		44.0	.	.	0.00	.	.	.	.	.	.	.	.	.	.	.	0.00
UNKN	EMERGENCY UNIT	0	GT	NG*		1145.9	.	.	.	.	.	0.00	0.00	0.00	.	.	0.00	0.00	0.00	0.00	0.00
HVPL	GRANBY	B	944 GT	NG*	FO2	44.0	**-1.57(b)**	.	.	.	.	.	.	.	.	.	.	.	.	.	-2.54
HVPL	GRANBY	A	944 GT	FO2	NG*	44.0	-3.89	.	.	.	.	.	.	.	.	.	.	.	.	.	-6.31
<HVPL>	Total Contribution to Fixed ($Miln)					4059.0	**22(a)**	45	52	61	57	61	63	70	67	40	46	43	40	36-	702

The annual average contribution to fixed costs is based on the sum of the dollar contributions
divided by the number of years and the maximum capacity during the study period.

Note: (a) Matches Reports No. 14a and No. 37. Differs from Report No. 58, due to the netting of Total O&M.
(b) Effect of must-run designation shown here.

Report No. 23: Unit Dispatch - *After Transactions*

Report No. 23 provides a monthly summary of energy production by unit, after purchases and/or sales. This report also indicates whether a unit burned its primary or alternate fuel. Revenues on sales are calculated using the ask price, while expenses for purchases are based on the bid price for energy. These prices are different from the values shown in Report No. 19, which uses the *higher* of the bid and ask prices, unless the **CONT2FIX** parameter is specified in the **<cntrl>** file.

The market areas printed in this report are selected by the **PRINT** or **PRINTALL** parameters in the **<cntrl>** file.
Data can be extracted from this report using the **CQXX.EXE** program.

Report No. 23 is directed to the file: **<rp23yyyy.rpt>** in the directory defined by **<repor >** where yyyy is the year.

Inter-Regional Electric Market Model (IREMM) Release1.16a(c) IREMM, Inc. 1995, Licensed: IREMMto 12/31/97 Report #23 Page 2290
Case Title: THIS IS THE BASE CASE FOR TESTING THE 1996 HVPL DATA <BASEHVPL> Tue Sep 30 17:32:37 1997
Summary of Unit Dispatch After Transactions
1997

<HVPL> 1997 ANNUAL AFTER TRANSACTIONS DISPATCH SUMMARY

UNIT NAME		TECH	FUEL	ALT	MW	$/MWH	R	JAN	FEB	MAR	APR	MAY	JUN	JLY	AUG	SEP	OCT	NOV	DEC	TOT. GWh	C.F.
AGGR. PUMPED STORAGE		PS	WAT		150.0	0.00		-4	-4	-4	-4	-4	-4	-4	-4	-4	-4	-4	-4	-49	-0.038
AGGR. CONV HYDRO		HY	WAT		132.0	0.00		34	31	34	33	34	33	34	34	33	34	33	34	405	0.350
CANTON	2	STC5	COL	NG	498.0	14.52		340	307	340	335	346	334	344	344	334	45	134	347	3549	0.814
VALLEY	2	STC2	COL		110.0	14.77		82	74	82	79	81	76	76	76	76	44	.	69	814	0.845
VALLEY	1	STC2	COL		110.0	14.77		82	74	82	79	.	30	76	76	76	81	79	82	817	0.848
EXPANSION UNITS	TCH1	CCN	NG		11.0	15.90		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
CANTON	1	STC3	COL		212.0	16.74		103	93	103	29	.	47	49	49	48	73	100	51	746	0.402
VALLEY	4	ZZ	FO2	NG	350.0	21.04		.*	80*	88*	172*	139*	120*	.*	18*	45*	.*	86*	.*	749	0.244
EXPANSION UNITS	TCH2	GTN	NG		11.0	23.52		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
HARTLAND	6	STG3	NGFX	FO6	200.0	24.14		.	.	.	.	.	.	46	46	.	.	0	.	93	0.053
VALLEY	3	STO4	FO6		350.0	34.79		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
HARTLAND	7	STO2	FO6		170.0	37.89		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
HARTLAND	8	STO2	FO6		170.0	37.89		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
GRANBY	B	GT	NG*	FO2	44.0	42.17		37	33	.	.	.	.	.	.	.	.	.	.	70	0.183
GRANBY	D	GT	NG*		44.0	42.17		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
GRANBY	C	GT	NG*		44.0	42.17		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
GRANBY	A	GT	FO2	NG*	44.0	42.17		37*	33*	37*	36*	36*	32*	.*	.*	.*	.*	.*	.*	211	0.548
EMERGENCY UNIT		GT	NG*		0.0	61.16		.	.	.	.	.	.	.	.	.	.	.	.	0	0.000
Energy (GWh)								710	722	762	760	633	668	622	640	608	274	428	578	**7405(b)**	
Fuel and O&M ($ Miln)								12.2	12.3	11.9	11.8	9.7	10.3	8.8	9.2	8.7	3.7	6.5	8.1	**113.2(a)**	
Expenses for Purchases ($ Miln)								5.4	3.7	3.0	1.3	2.6	1.4	1.7	1.8	2.0	9.1	7.8	7.2	47.0	
Revenues on Sales ($ Miln)								0.0	0.0	0.0	0.0	0.0	-0.6	-0.2	-0.5	0.0	0.0	0.0	0.0	-1.4	
Resulting Net Fuel and O&M ($ Miln)								17.7	16.1	15.0	13.0	12.3	11.1	10.3	10.4	10.7	12.8	14.3	15.3	**158.9(c)**	
Resulting Transmission Uplift ($ Miln)								0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Minimum Ask Strategy Dispatch Cost ($ Miln)								0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Note: Units using their <alternate> fuel in a month are indicated with an (*) after the monthly GWh change.
Dispatch cost, dispatch order, askstrategy, and Must-Run status flag are based on values used in December.
Revenues on Sales are based on ASK PRICES while Expenses for Purchases are based on BID PRICES.

Note: Report No. 21 shows the unit dispatches before transactions, while report No. 22 shows the unit dispatches after transactions.

(a) Matches Report No. 16.
(b) Matches Report No. 17 and Report No. 15h.
(c) Matches Report no. 15d.

Report No. 33: Summary of Emissions and Fuel Consumption in Quads

Report No. 33 contains six related reports. For convenience, they are referred to in this document as 33a -- 33f. These reports summarize the emissions of SO_2, NO_x, and CO_2 before and after transactions. The first three sub-reports provide the results on a State basis, and the last three sub-reports show them on market area basis.

Reports No. 33-a — 33-f are all directed to the file: **<rp33yyyy.rpt>** in the directory defined by **<repor >** where yyyy is the year.

Report 33-a: State level summary before transactions.

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 Inter-Regional Electric Market Model (IREMM) Release1.16a(c) IREMM, Inc. 1995, Licensed: IREMMto 12/31/97  Report #33    Page  2255
 Case Title:   THIS IS THE BASE CASE FOR TESTING THE 1996 HVPL DATA                          <BASEHVPL>   Tue Sep 30 17:32:37 1997
            SO2 / NOx Emissions Summary
                              1997


<1997> STATE LEVEL SO2, NOx and CO2 EMISSIONS - BEFORE TRANSACTIONS

                      EMISSION(kTONS)  QUADRILLION Btu OF FUEL BY FUEL CATEGORY (BILLION MBtu or QUADS)
                    -------------------- ------------------------------------------------------------------------------
       NOx  month
      Allow -----   SO2    NOx    CO2
State $/Ton st nd  ktons  ktons  Mtons   COAL     LIGN     URAN     RESD     DIST     WATR     OTHR     GAS
----- ----- -- -- ------ ------ ------ -------- -------- -------- -------- -------- -------- -------- --------
AL        0  1 12    410      0     61    0.525        .    0.313        .    0.000        .        .    0.105
AK        0  1 12      0      0      0        .        .        .        .        .        .        .        .
AZ        0  1 12      0      0      0        .        .        .        .        .        .        .        .
AR        0  1 12     52      0     18    0.163        .    0.131        .        .        .        .    0.012
CA        0  1 12      0      0      0        .        .        .        .        .        .        .        .
CO        0  1 12      0      0      0        .        .        .        .        .        .        .        .
CT        0  5  9     22      0      9    0.033        .    0.216    0.011    0.000        .    0.020    0.054
DE        0  1 12     35      0      7    0.040        .        .    0.004        .        .        .    0.038
DC        0  1 12      0      0      1        .        .        .    0.000        .        .        .    0.014
FL        0  1 12    242      0    107    0.463        .    0.291    0.057    0.005        .    0.094    0.828
GA        0  1 12    488      0     71    0.661        .    0.262    0.000    0.001    0.001        .    0.022
HI        0  1 12      0      0      0        .        .        .        .        .        .        .        .
ID        0  1 12      0      0      0        .        .        .        .        .        .        .        .
IL        0  1 12    699      0     57    0.498        .    0.802        .        .        .        .    0.083
IN        0  1 12   1015      0    117    1.077        .        .        .    0.000    0.000        .    0.067
  .
  .
  .
NB        0  1 12     28      0      7    0.033        .    0.048    0.018        .        .    0.004    0.021
NF        0  1 12      0      0      0        .        .        .        .        .        .        .        .
NS        0  1 12     54      0     10    0.092        .        .    0.005    0.000    0.000    0.002        .
PE        0  1 12      3      0      1        .        .        .    0.006    0.001        .        .    0.006
ON        0  1 12     77      0     17    0.137        .    0.969        .        .        .    0.011    0.027
QU        0  1 12      0      0      0        .        .        .        .        .        .        .    0.000
YK        0  1 12      0      0      0        .        .        .        .        .        .        .        .
AB        0  1 12      0      0      0        .        .        .        .        .        .        .        .
SA        0  1 12     69      0     13        .    0.123        .        .        .        .        .    0.006
MX        0  1 12      0      0      0        .        .        .        .        .        .        .        .
                    ------ ------ ------ -------- -------- -------- -------- -------- -------- -------- --------
TOTAL               10918     16   1959   13.705(a) 1.299    7.060    0.187    0.015    0.003    0.352    5.733
```

Note: (a) Matches Report No. 33-d and No. 31.

Report No. 42: Contributions to Capital

This report summarizes data that can be used to determine a unit's contributions to capital. It uses the revenues generated from energy sales based on the market clearing price and the energy generated. From this several categories of expenses are subtracted: fuel cost, variable O&M, environmental allowances, and transmission uplift. The resulting value is "contributions to fixed costs" from energy sales.

The contributions to capital are based on the "contributions to fixed costs" from energy sales plus the assigned capacity revenues minus the fixed O&M. The fixed O&M is calculated from the Total O&M input using either the escalated Total O&M Cost field in the **<unit>** file or the default technology based total O&M cost field in the **<tech>** file and subtracting out the variable O&M that was calculated during the dispatch simulations. Note: For this calculation, if the total O&M for the unit was zero (eg. not defined), the amount of the fixed O&M is still calculated the same (fixed O&M = total O&M minus variable O&M) and a negative "fixed O&M will be reported.

The footnotes indicate where these values can be found on other Reports. Individual jointly-owned unit ownership shares in different market areas are shown for each ownership share. This is in contrast to Report 58 where the information must be aggregated for the entire unit to make the economic retirement or economic viability decision.

Report No. 42 is directed to the file **<rp42yyyy.rpt>** in the directory defined by **<repor >** where yyyy is the year.

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Inter-Regional Electric Market Model (IREMM) Release1.18 (c) IREMM, Inc. 1995, Licensed: IREMMto 12/31/98  Report #42    Page  1238
 Case Title:   THIS CASE TESTS THE NEW 1997 DATA SET                                          <BASE1997>   Sat Nov 07 13:10:56 1998
           Unit Level Financial Pro-Forma Summary
                           2001

                  Annual Contributions to Capital by Unit  <BREC>

                                                                                | --- Revenues --- |   Fuel   Var O&M  Emission Xmission| Contrib.   Fixed | Capital
                                                                                |  Capacity  Energy |  Expense  Expense  Allowanc  Uplift |  to Fixed    O&M  |  Contrib.
                          GURF                 Fuel                             |   ($Miln)  ($Miln)|   ($Miln)  ($Miln)  ($Miln)  ($Miln) |   ($Miln)  ($Miln)|  ($Miln)
Comp     Unit Name          Id    Tech  Pri.  Alt.  Cap(MW)    GWh     Factor |     (a)      (b)  |     (c)      (d)      (e)      (f)  |     (g)      (h)  |     (i)
---- -------------------- ------ ----- ----- ---- -------- -------- --------|-------- --------|-------- -------- -------- --------|-------- --------|--------
BREC EXPANSION UNITS TCH3         ST    COL           18.4    161.5    1.000|   0.737    3.015|   1.986    0.145    0.000    0.121|    0.762   -0.145|   1.645
BREC D B WILSON      1      6823 STC5  BIT          420.0   2900.2    0.788|  16.800   54.824|  32.798    4.407    1.260    2.175|   14.184   -4.407|  35.391
BREC K C COLEMAN     1      1381 STC2  BIT          150.0   1088.8    0.829|   6.000   20.532|  13.473    1.225    0.920    0.817|    4.097   -1.225|  11.322
BREC K C COLEMAN     2      1381 STC2  BIT          150.0   1088.8    0.829|   6.000   20.046|  13.627    1.225    0.931    0.817|    3.447   -1.225|  10.672
HMPL HMP&L STATION 2 2      1382 STC2  BIT          161.0   1168.6    0.829|   6.440   21.458|  14.647    2.302    0.089    0.876|    3.543   -2.302|  12.285
HMPL HMP&L STATION 2 1      1382 STC2  BIT          154.0   1117.8    0.829|   6.160   20.525|  14.052    2.202    0.085    0.838|    3.347   -2.202|  11.709
BREC R D GREEN       1      6639 STC3  BIT          231.0   1669.8    0.825|   9.240   31.130|  21.176    3.101    0.145    1.252|    5.456   -3.101|  17.797
BREC K C COLEMAN     3      1381 STC2  BIT          155.0   1125.1    0.829|   6.200   21.271|  14.226    1.266    0.972    0.844|    3.963   -1.266|  11.430
BREC R D GREEN       2      6639 STC3  BIT          223.0   1612.0    0.825|   8.920   29.668|  20.641    2.994    0.141    1.209|    4.684   -2.994|  16.597
BREC R A REID        1      1383 STC1  BIT           65.0    390.0    0.685|   2.600    7.594|   5.396    0.527    0.369    0.292|    1.010   -0.527|   4.136
HMPL HENDERSON I     5      1372 STC1  BIT           10.0     22.3    0.254|   0.400    0.496|   0.383    0.030    0.026    0.017|    0.039   -0.030|   0.470
HMPL HENDERSON I     6      1372 STC1  BIT           26.0     43.3    0.190|   1.040    1.000|   0.745    0.058    0.051    0.032|    0.113   -0.058|   1.211
BREC EXPANSION UNITS TCH1         CCN   NG           36.9    178.0    0.551|   1.475    3.524|   3.059    0.100    0.000    0.133|    0.231   -0.100|   1.806
BREC EXPANSION UNITS TCH2         GTN   NG           18.4      0.0    0.000|   0.737    0.000|   0.000    0.000    0.000    0.000|    0.000    0.000|   0.737
HMPL HENDERSON I     SMAL 1372 IC    FO2   NG*         2.0      0.0    0.000|   0.080    0.000|   0.000    0.000    0.000    0.000|    0.000    0.000|   0.080
BREC R A REID        GT1  1383 GT    FO2           65.0      0.0    0.000|   2.600    0.000|   0.000    0.000    0.000    0.000|    0.000    0.000|   2.600
BREC EMERGENCY UNIT               GT    NG*       3838.5      0.0    0.000|  153.541   0.000|   0.000    0.000    0.000    0.000|    0.000    0.000|  153.541
-------------------------                                    --------                                                                  --------            --------
                                                             12566.2                                                                   44.877             293.430

 Notes: (g) = (b) - (c) - (d) - (e) - (f);  Where (g) matches Report No. 19 and (b) matches Report No. 40
        (h) = Escalated Total O&M - (d);    Where (h) and (d) match Report No. 58
        (i) = (a) + (g) - (h);              When a zero total o&m is input, column (h) means that variable O&M should be added back in.
```

Report No. 79: Operating Reserve Group Summary Information

This report provides the operating reserve group details for the acquisition of both spinning or quick start reserve on an hourly basis. Each operating group can have spinning reserve or quick start reserve capacity that is required based on a combination of a fixed minimum amount or a percent of the hourly loads. The spinning reserve must come from units that are committed in the unit commitment logic.

Report No. 79 is directed to the file **<rp79yyyy.rpt>** in the directory defined by **<repor >**where yyyy is the year.

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 Inter-Regional Electric Market Model (IREMM) Release 2.03.21(c) IREMM, Inc. 1995, Licensed: IREM to 12/31/99  Report #79    Page   101
 Case Title:   THIS CASE TESTS THE NEW 1998 DATA SET FOR THE EASTERN INTERCONNECTED           <BAS98NOG>   Thu Sep 09 17:27:33 1999
           Operating Reserve Group Summary Information


                Operating Reserve Summary for Month JLY 2004    Day  1    Hour  1

     |       Target Criteria         |           Reserve MW Requirements             |       | Obtained MW Requirements|
     |-------------------------------|-----------------------------------------------| Total |-----------------------------------------|   Deficient MW   |
Oper.|Fx Spin PctSpin Fx Quik PctQuik|Fx Spin PctSpin  Total  Fx Quik PctQuik  Total | Req'd |  Hydro  PStore  Spin    Quick    Total |   Spin     Quick |
-----|------- ------- ------- -------|------- ------- ------- ------- ------- -------|-------|------- ------- ------- -------|--------| -------- --------|
OECAR|100.000   0.020 100.000   0.020|  100.0  1167.3  1267.3   100.0  1167.3  1267.3| 2534.7|  850.8  3918.0     0.0  1267.3|  6036.1|
OFRCC|100.000   0.020 100.000   0.020|  100.0   399.8   499.8   100.0   399.8   499.8|  999.5|    8.2     0.0   491.6   499.8|   999.5|
OHYQB|  0.000   0.000   0.000   0.000|    0.0     0.0     0.0     0.0     0.0     0.0|    0.0| 2217.2     0.0     0.0     0.0|  2217.2|
OMAAC|100.000   0.020 100.000   0.020|  100.0   525.4   625.4   100.0   525.4   625.4| 1250.9|  846.5  1589.7     0.0   625.4|  3061.7|
OMAIN|100.000   0.020 100.000   0.020|  100.0   470.9   570.9   100.0   470.9   570.9| 1141.7|  433.5   866.3     0.0   570.9|  1870.7|
OMAP1|100.000   0.020 100.000   0.020|  100.0    34.3   134.3   100.0    34.3   134.3|  268.5| 2589.8     0.0     0.0   134.3|  2724.0|
OMAP2|100.000   0.020 100.000   0.020|  100.0    36.7   136.7   100.0    36.7   136.7|  273.4|  152.6     0.0    96.1    24.7|   273.4|
OMAPP|100.000   0.020 100.000   0.020|  100.0   355.6   455.6   100.0   355.6   455.6|  911.1| 2221.2     0.0     0.0   352.1|  2573.2|
OMARI|100.000   0.020 100.000   0.020|  100.0    49.2   149.2   100.0    49.2   149.2|  298.4| 1192.2     0.0     0.0   149.2|  1341.4|
ONEPL|100.000   0.020 100.000   0.020|  100.0   254.1   354.1   100.0   254.1   354.1|  708.2| 1147.2  1907.1     0.0   354.1|  3408.4|
OSENY|100.000   0.020 100.000   0.020|  100.0   169.9   269.9   100.0   169.9   269.9|  539.7|   71.1     0.0   241.6   227.0|   539.7|
OONHY|100.000   0.020 100.000   0.020|  100.0   293.0   393.0   100.0   293.0   393.0|  786.0| 3496.9     0.0     0.0   393.0|  3889.9|
OSOUT|100.000   0.020 100.000   0.020|  100.0   409.8   509.8   100.0   409.8   509.8| 1019.6| 3370.0  2959.9     0.0   134.8|  6464.7|
OSPP |100.000   0.020 100.000   0.020|  100.0   483.0   583.0   100.0   483.0   583.0| 1166.0| 1437.1   618.3     0.0   583.0|  2638.4|
OTVA |100.000   0.020 100.000   0.020|  100.0   293.5   393.5   100.0   293.5   393.5|  787.1| 3582.3  3040.9     0.0     0.0|  6623.2|
OENT |100.000   0.020 100.000   0.020|  100.0   278.4   378.4   100.0   278.4   378.4|  756.8|  165.9     0.0   212.6   378.4|   756.8|
OUPNY|100.000   0.020 100.000   0.020|  100.0   166.0   266.0   100.0   166.0   266.0|  532.0| 2981.9  1431.6     0.0   266.0|  4679.6|
OVACR|100.000   0.020 100.000   0.020|  100.0   535.8   635.8   100.0   535.8   635.8| 1271.7| 1996.1  4258.1     0.0   635.8|  6890.0|
OERCO|100.000   0.020 100.000   0.020|  100.0   603.8   703.8   100.0   603.8   703.8| 1407.7|  382.9     0.0   320.9   703.8|  1407.7|
```

Report No. 85: Hourly Bid/Ask Prices (as Appropriate) by Market Area

Report No. 85 shows the prevailing prices that a market area will see. In the event that the market area is a seller, the price shown will be the ask price. In the event that a market area is a buyer, the price shown will be its bid price. This distinction is made in the hourly prices, as opposed to the monthly models, because in an hourly analysis, a market area cannot be both a buyer and a seller. This is in contrast to the monthly model where a load level is a collection of hours and the market area could be a seller at certain times and buyer at others in a single load level.

Report No. 85 is directed to the file: **<rp85yyyy.rpt>** in the directory defined by **<repor>**; yyyy is the year

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"1999","LY  EASTERN  : AUG  01, 1998| : NO      PRICE SQUEEZING: ENERGY OUTLOOK BASE    "
  "Hourly Bid/Ask Prices (as appropriate) by Market Area"
 "JAN 1999","<HE__REFR>"," Eastern Standard Time"
 "Day","Hour","Loadlevel","AEP " ,"BUCK" ,"BREC" ,"CIN " ,"CP  " ,"DECO" ,"DP&L" ,"EKPC" ,"HEC " ,"IP&L" ,"KUC "
   1    1    0   14.51   14.75   14.75   14.25   14.75   14.65   14.00   14.25   13.50   13.50   14.75
   1    2    0   14.36   14.75   14.00   14.00   14.50   14.30   14.00   14.25   13.50   13.50   14.00
   1    3    0   13.80   14.00   13.75   13.78   13.75   14.08   13.75   14.00   13.50   13.50   13.75
   1    4    1   14.25   14.25   14.00   14.25   14.25   14.55   14.25   14.25   14.00   14.00   14.00
   1    5    1   14.25   14.25   14.25   14.00   14.25   13.48   14.25   14.25   14.00   14.00   14.25
   1    6    1   14.75   15.25   14.50   14.00   15.00   14.75   15.25   14.50   14.00   14.00   14.50
   1    7    2   15.26   15.75   15.00   14.71   15.50   15.34   14.75   15.00   14.50   14.50   15.00
   1    8    2   15.36   15.75   15.00   14.70   15.50   15.31   15.00   15.25   14.50   14.50   15.07
   1    9    2   15.59   15.75   16.50   15.00   15.75   15.18   15.00   15.25   14.50   14.50   16.50
   1   10    2   16.05   15.75   17.25   15.00   17.25   17.03   14.65   15.50   14.50   14.50   17.25
   1   11    2   16.76   16.75   18.25   16.25   17.25   18.00   13.88   17.25   14.50   14.50   18.25
   1   12    2   16.75   16.75   15.75   16.25   17.25   20.00   15.75   16.50   14.50   14.50   15.75
   1   13    2   17.00   17.00   15.75   17.39   17.25   19.50   15.75   16.50   14.50   14.50   15.75
   1   14    2   15.75   15.75   15.75   16.25   20.00   20.00   15.75   14.25   14.50   14.50   15.75
   1   15    2   16.75   16.75   18.25   16.25   17.25   24.00   15.25   15.25   14.50   14.50   18.25
   1   16    2   16.75   16.75   18.25   16.25   18.25   24.25   15.75   15.25   14.50   14.50   18.25
   1   17    2   17.14   15.75   17.50   15.00   20.00   20.00   15.75   17.00   14.50   14.50   17.50
   1   18    2   17.66   17.75   18.25   17.29   17.50   20.00   17.50   17.00   15.25   16.25   18.25
   1   19    2   17.75   17.75   18.25   17.36   16.50   16.51   16.50   17.50   15.25   16.75   18.25
   1   20    2   17.34   17.25   18.25   16.86   17.25   20.00   17.50   18.25   15.25   16.25   18.25
     .
     .
     .
  31   13    2   27.62   24.25   30.25   29.50   25.75   23.35   19.75   29.50   17.86   27.25   18.73
  31   14    2   27.33   24.50   29.50   24.76   26.50   26.02   29.00   28.00   21.83   26.50   23.40
  31   15    2   27.85   24.50   29.00   27.50   24.75   24.08   28.75   28.75   24.50   24.50   29.00
  31   16    2   27.64   24.50   27.75   27.50   24.75   24.96   27.75   27.75   24.75   24.75   21.75
  31   17    2   25.56   26.50   31.00   28.75   25.75   25.70   28.75   28.00   28.00   28.00   23.91
  31   18    2   29.94   29.25   32.25   32.25   31.50   28.58   31.50   32.25   28.50   26.72   32.25
  31   19    2   32.97   29.75   38.50   33.51   32.50   32.21   32.75   31.50   29.75   29.75   38.50
  31   20    2   31.46   29.75   32.25   31.13   31.75   29.17   31.50   31.50   29.75   32.75   32.25
  31   21    2   29.84   26.50   32.25   30.00   29.00   28.94   30.00   31.00   26.50   30.25   31.00
  31   22    2   28.94   24.71   29.25   29.25   27.25   25.64   29.50   29.25   26.29   27.25   29.25
  31   23    1   24.25   24.25   25.75   24.94   23.00   25.20   27.25   26.00   24.25   28.00   25.75
  31   24    1   21.35   18.50   18.00   17.50   17.75   17.75   17.75   18.50   15.00   15.00   18.50
```

Report No. 87: Daily LOLE by Operating Group

Report No. 87 shows the daily Loss of Load Expectation(LOLE) for each operating reserve group. The loss of load expectation is calculated using a normal approximation for the capacity outage distribution. This outage distribution is calculated using a binomial distribution for capacity availability and an assumption that these outages are normally distributed. Once this outage distribution is calculated, it is compared to each hourly load and the probability of the load exceeding the available capacity in the operating group is calculated. The maximum LOLE for an operating group in a day is 24.000 because the maximum probability of a loss of load event in a singe hour is 1.000 and there are 24 hours in a day.

The LOLE values calculated are isolated LOLE values based on an operating group's native resources and native loads. This approach does not reflect capacity available from neighboring regions. Future enhancements may include inter-Operating Group reliability assistance, but are beyond the scope of the analysis presented in Reports 87 and 88.

Because Inter-Operating Group reliability assistance is not considered, the operating groups should be sufficiently large so that no single unit or sub group of units is 'large' compared to the total capacity available within the operating reserve group.

Report No. 87 is directed to the file: **<rp87yyyy.rpt>** in the directory defined by **<repor>**, where yyyy is the year.

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Inter-Regional Electric Market Model (IREMM) Release 2.03.21(c) IREMM, Inc. 1995, Licensed: IREM to 12/31/99  Report #87    Page   855
 Case Title:   THIS CASE TESTS THE NEW 1998 DATA SET FOR THE EASTERN INTERCONNECTED           <BAS98NOG>   Thu Sep 09 19:57:01 1999
           Daily LOLE by Operating Group


                Operating Reserve Group Isolated LOLE Summary for Month JLY 2004

Oper.|------------------------------------------------------------ Days of the Month ----------------------------------------------
Group|      1       2       3       4       5       6       7       8       9      10                 28      29      30      31
-----| ------- ------- ------- ------- ------- ------- ------- ------- ------- -------    ...     ------- ------- ------- -------
OECAR|   .       .       .       .       .       .       .       .       .       .         ...     0.0174   .       .       .
OFRCC|  0.0524  0.0013  0.0485  0.0001   .       .      0.2794  0.4335  0.0148   .         ...     0.0447  0.0060  0.0474  0.2534
OHYQB|   .       .       .       .       .       .       .       .       .       .         ...      .       .       .       .
OMAAC|  0.0003   .      0.0625   .       .       .      0.0007  0.0471  0.4489   .         ...     3.1908   .       .       .
OMAIN|  0.4306  0.1453   .       .       .       .       .       .       .       .         ...     0.0367   .       .       .
OMAP1|   .       .       .       .       .       .       .       .       .       .         ...      .       .       .       .
OMAP2|  0.0755  0.0005   .       .       .       .      0.0012  0.0176  0.0062  0.0070    ...     0.0653  0.0053  0.0018  0.0027
OMAPP|  0.0633   .       .       .       .       .       .      0.0001   .       .         ...     0.0425   .       .       .
OMARI|   .       .       .       .       .       .       .       .       .       .         ...     0.0001   .       .       .
ONEPL|  0.8756  0.0496  0.0015   .       .       .      0.0070  0.0059  0.5477  0.0001    ...     5.1066  0.0004  0.0001  0.0190
OSENY|  3.5790  0.4182  2.1127  0.0025  0.0001  0.0002  0.6435  3.6204  5.4566  0.3688    ...    10.6371  0.5799  0.1053  1.6837
OONHY|  1.5243  0.5303  0.1671  0.0002   .       .      0.2459  0.2784  1.1667  0.0775    ...     3.9353  0.1310  0.0832  0.3938
OSOUT|  0.0083  1.4478  2.6213  0.0017   .       .       .      0.0399  0.0095  0.3218    ...     4.1310  2.4527  0.4688   .
OSPP |  0.1142   .       .       .       .       .       .       .      0.0004  0.0002    ...     0.0001   .       .       .
OTVA |  1.0901  5.3138  3.8299  0.0003   .       .      0.0219  0.6255  0.8683  1.0421    ...     6.4473  1.9327  0.9898  0.0613
OENT |  0.1006  0.5589  0.5829  0.0005   .       .      0.0001   .      0.0015  0.0264    ...     0.3512  0.1458  0.0029  0.0075
OUPNY|   .       .       .       .       .       .       .       .       .       .         ...      .       .       .       .
OVACR|   .       .      0.3894  0.0011   .       .      0.0018  0.0688  0.1263   .         ...     3.4842  0.0003   .       .
OERCO|  0.1128  0.3831  0.2105   .       .       .      0.0126  0.0014  0.0055  0.0416    ...     3.8260  3.0439  0.0345  0.0449
```

Report No. 91: Detailed Hourly Price Statistics

Report No. 91 provides detailed statistical summaries for each load level designation and each month. The price statistics are based on the bid or ask price as appropriate in Report No. 85. The statistics that are provided in this report are:

1. The arithmetic mean of the distribution in each load level and for all hours,
2. The standard deviation of the distribution in each load level and for all hours,
3. The minimum of the distribution in each load level and for all hours,
4. The maximum of the distribution in each load level and for all hours,
5. The total amount of energy sold in each load level and for all hours,
6. The total amount of energy purchased in each load level and for all hours.

Report No. 91 is directed to the file: **<rp91yyyy.rpt>** in the directory defined by **<repor>**, where yyyy is the year.

```
Inter-Regional Electric Market Model (IREMM) Release2.01d(c) IREMM, Inc. 1995, Licensed: IREMMto 12/31/98  Report #91   Page  13
  Case Title: LY  EASTERN  : AUG  01, 1998| : NO    PRICE SQUEEZING: ENERGY OUTLOOK BASE  <HE__REFR>   Mon Aug 24 23:28:50 1998
             Condensed Hourly Price Statistics
                                  1999

 reference time zone is: < Eastern Standard Time>

                                       Monthly Summary of Price Statistics <JAN 1999>


                    Off-Peak                                          Mid-Peak   On-Peak                  All-Hours
  Mkt-  ---------------------------------------------- ---------  -------- ----------------------------------------------
  Area     Mean   Std-Dev Minimum Maximum   Sales   Purch                      Mean  Std-Dev Minimum Maximum  Sales   Purch
 ------ ------- -------- ------- ------- ------- -------         ...        ------- ------- -------- ------- ------- -------
 "AEP ",  16.11,   1.09,  13.80,  23.14,    372,      0,          ...         20.63,   4.71,  13.80,  35.43,   2128,      0
 "BUCK",  16.23,   1.11,  14.00,  23.50,      0,     64,          ...         20.33,   4.02,  14.00,  32.50,     53,    150
 "BREC",  16.91,   1.46,  13.50,  23.50,      0,    271,          ...         21.29,   5.08,  13.50,  38.50,      0,   1816
 "CIN ",  15.81,   1.43,  13.17,  20.84,    146,      0,          ...         20.73,   4.96,  13.17,  35.50,    877,      0
 "CP  ",  16.38,   1.71,  13.75,  24.75,      0,    117,          ...         21.07,   4.46,  13.75,  32.50,      0,    600
 "DECO",  16.74,   2.50,  14.08,  27.75,    505,      0,          ...         21.24,   4.28,  13.48,  32.21,   3691,      0
 "DP&L",  15.85,   1.01,  13.75,  18.50,     44,      0,          ...         20.50,   4.95,  13.75,  35.25,    123,     31
   .
   .
   .
 "WPSC",  17.97,   2.92,  14.50,  27.75,      0,     20,          ...         22.54,   4.46,  14.50,  32.50,      0,    154
 "WVPA",  16.24,   1.48,  13.75,  19.50,      0,     39,          ...         20.94,   4.98,  13.75,  35.50,      0,    294
 "AYP ",  17.88,   3.77,  14.00,  28.25,     77,      0,          ...         23.25,   6.13,  14.00,  39.00,    472,      0
 "FRST",  15.91,   1.02,  13.75,  19.00,      3,     92,          ...         20.24,   4.61,  13.75,  32.75,      7,    781
 "FLA ",  18.97,   1.89,  16.00,  24.25,      1,    252,          ...         22.76,   7.59,  12.62, 150.00,    281,   1101
 "MAAC",  20.54,   3.00,  16.50,  27.00,    226,     40,          ...         26.08,   4.81,  16.50,  37.25,    427,   1865
 "CECO",  16.07,   1.51,  12.50,  19.00,      0,    115,          ...         20.97,   4.88,  12.50,  35.50,    198,    594
 "AMRN",  15.38,   2.10,   9.75,  20.00,      1,     62,          ...         21.13,   5.16,   9.75,  38.00,      5,    470
 "SCIL",  16.78,   1.50,  14.07,  22.64,    237,      0,          ...         21.53,   4.50,  13.50,  33.58,   1681,      1
 "WUMS",  15.80,   1.76,  12.50,  19.75,     17,     19,          ...         21.17,   5.06,  12.50,  35.75,     30,    357
 "WIMS",  16.77,   0.95,  14.25,  18.75,      0,     12,          ...         23.34,   5.83,  13.75,  39.50,      0,     38
 "MAPP",  14.06,   1.38,  12.23,  18.89,    625,      0,          ...         20.09,   5.51,  12.23,  36.86,   1987,     24
 "MH  ",  13.06,   2.89,   9.12,  18.75,     61,      0,          ...         17.93,   4.94,   8.94,  35.00,    278,      0
 "SASK",  14.51,   2.07,  10.50,  20.00,      2,      1,          ...         21.14,   5.82,  10.50,  36.00,      3,     77
 "UPNY",  20.76,   3.64,  17.00,  30.50,      0,     89,          ...         27.12,   5.12,  16.75,  36.75,    126,    379
```