PJM Simulation of PJM/MISO Single Economic Dispatch
Production Cost Analysis

Table of Contents

Introduction

In support of their October 31, 2005 Joint and Common Market filing with the FERC, PJM and MISO conducted a cost/benefit analysis of the creation of a single economic dispatch across the two RTO footprints. The benefits used in this analysis were approximated based upon the decrease in production cost that would result from the increase in energy exchange sufficient to cause price convergence between the two systems. PJM and MISO indicated to stakeholders that a more comprehensive analysis would be conducted following the filing in order to verify these benefit calculations.

A more comprehensive analysis, using commercially available production cost/power flow analysis tools, has been completed by both MISO and PJM. This paper discusses the methodology, key elements, and specific results of the analysis conducted at PJM.

PJM and MISO each set out to independently, but in a cooperative fashion (as each RTO is more familiar with its own system modeling and simulation tools), produce model results that are consistent and representative of current market conditions. Each RTO used commonly available energy market simulation tools based on security-constrained commitment and economic dispatch algorithms. Both algorithms use detailed electrical models of the Eastern Interconnection, along with transmission and generator constraints to produce hourly production cost and bus level LMP results.

PJM and MISO met periodically and exchanged appropriate 2006 base case model information. Data that was exchanged by the RTO's for input consideration into the respective models included base load flow data, fuel prices, unit capacities, transmission constraint modeling, area load representation, both simulated and real actual and scheduled interchange values, O&M cost, and environmental cost components.

It is important to note that the base case on which the production cost savings are based is benchmarked against the actual market conditions experienced over the last year. Therefore, the production cost savings that result from the analysis are inclusive of the benefits that will be achieved via implementation of the various Joint and Common Market (JCM) initiatives already under development or investigation. Specifically, the following JCM initiatives are expected to increase the convergence of the two markets and achieve a significant portion of these savings:

- PJM implementation of marginal losses;
- Alignment of PJM Operating Reserve and MISO Revenue Sufficient Guarantee products;
- Moving Joint-Owned Units between markets;
- Alternative border pricing point mechanisms.

Other potential JCM initiatives are also being considered that could further enhance the convergence of the two markets. In addition, PJM and MISO are and will be continuously analyzing and improving the operation of the Market-to-Market coordination that was implemented as Phase 2 of the Joint Operating Agreement. The initiatives described above are expected to achieve a significant portion of the production cost savings estimated in the simulations, at substantially less cost than a single unit commitment and dispatch. Once the above initiatives have been incorporated into the operations of the two RTOs for a time period significant enough over which to judge their effectiveness, an analysis could be conducted that would indicate more definitively the remaining benefits that might be achieved through a single economic dispatch.

Analysis Methodology

The objective of this analysis was to estimate the expected annual production cost savings of a single MISO/PJM economic dispatch. This analysis simulated a single unit commitment and dispatch over the combined PJM and MISO footprints. The analysis was performed using the General Electric Multi-Area Production Simulation (MAPS) program. The database used to perform the analysis was purchased from General Electric - Energy Consulting which maintains the database using publicly available data sources.

The MAPS/MW flow program is a commonly-used energy market simulation tool. This program can calculate the hourly production cost of generators operating within the constraints on generation dispatch that are imposed by security constrained operation of the transmission system and market area boundary conditions. The program uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved AC powerflow model, to calculate the power flows for each hourly generation dispatch in the simulation. The program provides production costing results and hourly spot prices at individual buses and flows on selected transmission lines. The MAPS program formulates the generating system dispatch as a linear programming problem where the objective function is to minimize production costs subject to electrical constraints. The objective of the commitment and dispatch algorithms is to determine the most economic operation of the generating units on the system. The simulation is subject to the operating characteristics of the individual generating units, the constraints imposed by the transmission system, and operating and spinning reserve requirements.

The methodology of using GE MAPS to perform generation production cost analysis was chosen because it can perform simulations based on security-constrained unit commitment and economic dispatch. The program can simulate a locational pricing-based market by using the security-constrained economic dispatch feature to match load and generation on an hourly basis and to calculate hourly market clearing prices. This approach provides a model that can simulate realistic economic dispatch scenarios and market operating conditions using a full transmission model and using realistic generation operating constraints.

The market simulations were performed with an Eastern Interconnection model in which commitment and dispatch constraints create the regional market areas including PJM and MISO. In this simulation mode, hurdle rates set the conditions in which economic transactions flow between the market areas. This simulation modeled operating conditions that are similar to current operations in which each market area performs its own least-cost unit commitment and economic dispatch to meet the market area demand and reserve requirements.

In order to estimate the production cost benefits of a single MISO/PJM economic dispatch, two simulations are required. The first (Base case), which is meant to simulate current operating conditions, has hurdle rates between MISO and PJM. The second (Alternative Case), which is meant to simulate the single economic dispatch, has the hurdle rates between MISO and PJM removed. The production cost difference between the two simulations provides the estimated production cost savings of moving to a single economic dispatch.

Base Case Hurdle Rate Determination

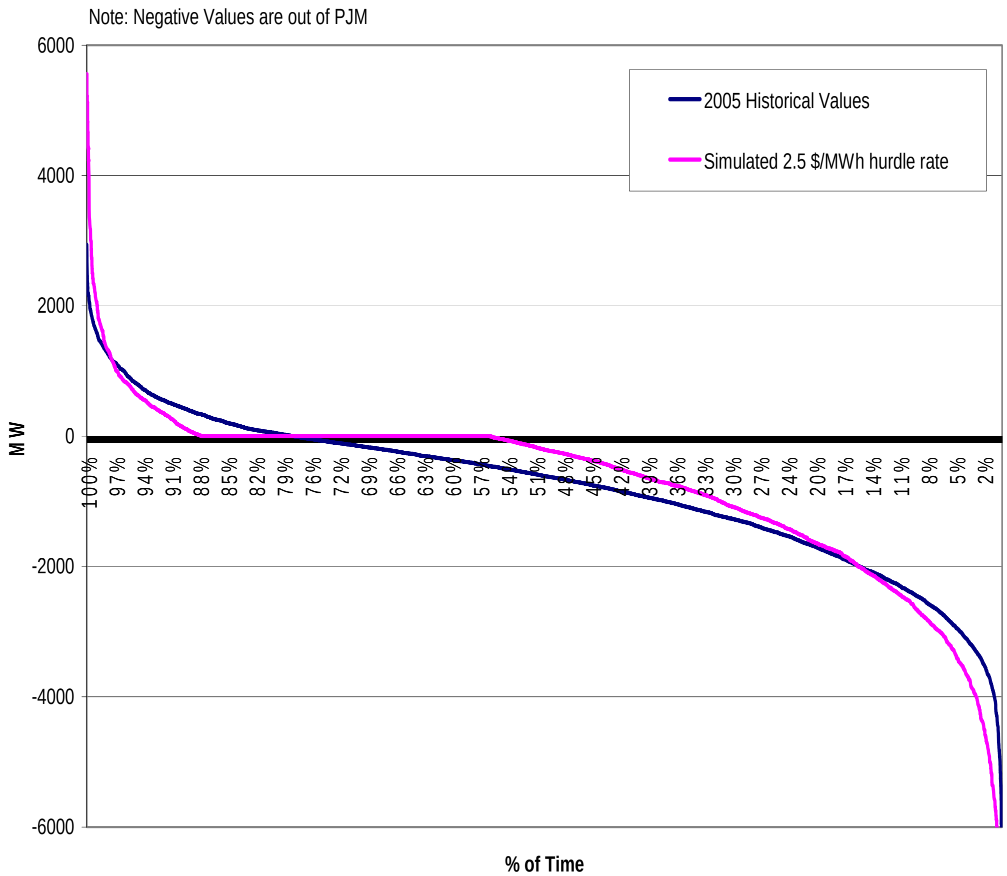
A hurdle rate sets the conditions in which economy interchange can be transacted between neighboring market areas. It represents a minimum savings level ($/MWh) that must be achieved before energy will be scheduled between the various modeled market areas.

In this base case two hurdle rates are used, one for the commitment and a separate one for the dispatch. The commitment hurdle rate sets the level that a unit commitment change will be made to allow scheduled energy to flow between market areas. The dispatch hurdle rate sets a level that will allow economic dispatch to be changed to allow scheduled energy to flow between market areas.

In order to determine the base case MISO/PJM dispatch hurdle rate, a sensitivity analysis was performed. The simulated scheduled interchange between MISO and PJM was compared to actual historical scheduled interchange values between the two market areas for various hurdle rate levels. The dispatch hurdle rate that produced the best comparison and became the base case hurdle rate was at 2.5 $/MWh. See Chart 1 for the comparison of the simulated results to historical interchange with the 2.5 $/MWh hurdle rate.

Chart 1 – Historical MISO/PJM Scheduled Interchange Vs Simulated with $2.5 /MWh Hurdle Rate

Net MISO TIES
Scheduled Interchange Duration Curve



For additional information pertaining to the base case, see the Appendix.

Adjusted Production Cost Results

The generation production costs are the costs to operate the generation at the desired level of output for each simulation hour. The generation production cost is defined as the summation of the hourly fuel cost, variable operation and maintenance cost, start-up cost, and environmental cost (includes SOx & NOx) for each thermal generating unit when dispatched at the simulated output level.

Because generation is being used to supply more or less than a market area's load (i.e. used for economy interchange to/from various market areas), the production cost of generation without an offset for the value of producing the economy interchange is not appropriate for measuring the benefits of single economic dispatch areas. Put another way, by offsetting the total production cost of generation with a value (credit offset for sales/ debit offset for purchases) for economy interchange allows a comparison of cases in which MISO and PJM transact with other market areas.

The formula for adjusted production cost is shown below. Note that the hourly purchase and sale quantities are valued at the market area marginal value in each hour.

Adjusted Production Cost = {Production Cost of Generators + (Load Weighted LMP * Purchase) - (Generator Weighted LMP * Sale)}

Table 1 below indicates the adjusted production cost savings of the single economic dispatch area resulting from the PJM simulations.

Table 1 –Single Economic Dispatch Adjusted Production Cost Savings

Case	**PJM Adjusted Production Cost Savings**	**MISO Adjusted Production Cost Savings**	**Total Adjusted Production Cost Savings ($M)**
$2.5 Hurdle	71.2	- 4.8	66.4

Appendix

Base Case Modeling Characteristics

The MAPS/MW base case used in this study utilized a detailed representation of the transmission systems and energy markets of the Eastern Interconnection. It was delivered to PJM by General Electric Energy Consulting (GE-EC) in late 2005. The base case provides the basis for a realistic simulation of 2006 conditions providing hourly results for key energy market metrics.

Key Inputs

Load

The annual peak-hour demand, annual energy demand, and hourly load shape for the each of the regions (with the exception of the annual peak-hour and energy demand for PJM) was developed from Platts/RDI BaseCase projections. PJM peak-hour and annual energy demand was derived from the PJM 2005 Load Forecast Report. Historical year 2002 actual loads were used to derive the hourly load shapes. The peak hour demand and annual energy values for MISO and PJM are shown in Table 1. The input load values included system losses.

Table 1 – 2006 Annual Energy and Peak Demand

Electricity Demand	PJM	MISO
Annual Energy (GWh)	721163	601800
Peak Demand (MW)	138474	110300

Generation- The generating capacity, location, unit type, input fuel, heat rate, environmental emission rates, and unit operating characteristics were primarily derived from the Platts/RDI BaseCase (2004 - 4th quarter release) and augmented by GE-EC analysis. PJM made specific unit level changes were known discrepancies existed.

Fuel Cost

The generation fuel cost data was provided by GE-EC based on a 2005 4th quarter update of the Platts/RDI BaseCase. These costs in $/MMBtu are supplied on a NERC region basis for coal, oil, and gas. Other fuel costs remain the same for the entire Eastern Interconnection.

The fuel prices used for the thermal units spanning the MISO/PJM NERC regions are shown in Table 2.

Table 2 – 2006 Fuel Prices ($/MMBtu)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
ECAR												
Coal	1.70	1.69	1.70	1.70	1.70	1.71	1.70	1.71	1.71	1.70	1.71	1.70
Distillate Oil	9.21	9.26	8.50	10.52	9.98	9.33	9.28	10.32	12.67	11.80	11.17	9.93
Residual Oil	7.32	6.40	6.22	6.36	7.00	6.27	6.04	6.24	6.79	6.35	6.65	6.51
Natural Gas	11.21	11.31	11.30	11.07	10.39	10.46	10.42	10.47	10.62	10.65	9.51	9.55
Nuclear	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
MAAC												
Coal	2.10	2.10	2.11	2.09	2.08	2.07	2.04	2.06	2.05	2.06	2.09	2.09
Distillate Oil	9.83	10.22	10.23	9.79	9.41	12.80	9.25	9.11	10.90	10.24	10.11	10.08
Residual Oil	6.77	6.52	6.09	6.13	6.42	6.99	6.56	6.39	6.18	6.78	6.82	6.50
Natural Gas	11.63	11.73	11.68	11.34	10.57	10.61	10.68	10.69	10.76	10.80	9.71	9.88
Nuclear	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
MAIN												
Coal	1.23	1.25	1.25	1.25	1.26	1.24	1.23	1.23	1.22	1.22	1.21	1.19
Distillate Oil	9.11	9.65	9.96	13.22	9.80	9.33	10.31	8.92	10.85	10.36	10.00	10.46
Residual Oil	5.88	6.30	5.99	6.03	6.99	6.49	7.06	7.24	6.30	6.70	6.56	6.61
Natural Gas	10.95	11.04	11.02	10.78	10.07	10.11	10.09	10.18	10.24	10.30	9.18	9.23
Nuclear	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
MAPP												
Coal	0.98	0.99	1.00	1.02	1.02	1.01	1.00	0.99	1.00	1.00	0.97	0.94
Distillate Oil	9.07	9.86	9.02	9.00	9.82	9.98	9.41	9.99	11.32	12.73	11.30	10.47
Residual Oil	7.33	10.35	4.11	10.63	2.85	5.43	3.74	6.51	7.06	7.35	7.55	5.26
Natural Gas	10.76	10.86	10.85	10.64	9.96	10.02	9.94	10.03	10.20	10.24	9.11	9.10
Nuclear	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
VACAR												
Coal	2.37	2.38	2.38	2.39	2.41	2.39	2.42	2.42	2.42	2.43	2.42	2.42
Distillate Oil	10.54	12.04	9.34	10.66	10.24	9.83	9.66	9.52	10.05	10.37	9.28	10.45
Residual Oil	6.83	7.47	5.76	7.91	7.39	7.02	6.68	6.79	5.87	4.74	5.85	5.85
Natural Gas	11.35	11.44	11.40	11.06	10.36	10.41	10.49	10.49	10.56	10.60	9.46	9.64
Nuclear	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56

O&M Costs

Operation and Maintenance (O&M) costs were developed by GE-EC based on analysis and use of the Platts/RDI Basecase data. Table 3 shows a summary of the range of the values applicable to generation plants in the MISO/PJM market areas.

Table 3 – Variable O&M Costs

	Variable Costs ($/MWh)
Nuclear	0.61
Gas Turbines	4.0 0 - 4.42
Steam Turbines	0.6 7 - 1.56
Combined Cycles	1.56 - 1.66

Outage Rates

The generation outage rates include both a planned maintenance and a forced outage rate. The rates, which represent a percent of time on an annual basis, are based on GE-EC analysis of historic NERC GADS data. Nuclear units and some steam turbines in the market area have predefined planned maintenance schedules. Table 4 shows the outage rates used in the simulations, where predefined maintenance is not used.

Table 4 – Generation Outage Rates

Unit Type	Planned Outage Rate	Forced Outage Rate
Nuclear	N/A	.06
Gas Turbines	.015	.030
Steam Turbines	.054 - .072	.025 - .047
Combined Cycle	.015 - .048	.030 - .033

Environmental Cost

The modeled environmental costs are comprised of unit emission rates and a trading cost ($/Ton) for SOx and NOx.. The unit emission rates were developed by GE-EC through the use of the Platts/RDI Basecase data. The SOx and NOx trading costs were made to be consistent with MISO's current basecase. Table 5 shows the emission cost per ton of effluent in the simulated market area.

Table 5 – Emission Cost ($/Ton)

Emission Type	Cost ($/Ton)
SOx (Jan-Dec)	1565.50
NOx (May-Oct)	2687.50

Transmission Representation

A full network transmission model of the Eastern Interconnection was used for this base case. The load flow was delivered as part of the GE-EC base data and was derived from a 2008 MMWG representation. As part of the simulation the HVDC line between Raritan River 230kV and North Bridge 138kv was removed from service.

Key normal and single contingency constraints were modeled for the EHV transmission system in addition to major transmission interfaces in the MISO/PJM market areas. GE-EC analyzed various NERC regional reports and various other reports to determine appropriate modeling of flowgates, interface limits, line limits, and contingencies for the Eastern Interconnection.