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COMMENTS
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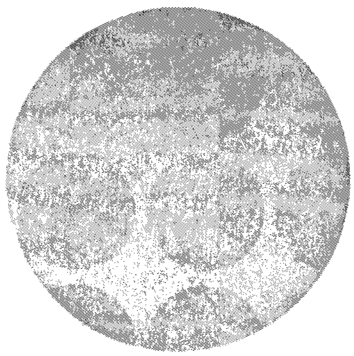

Putting Competitive Power Markets to the Test

The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies

JULY 2005

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Global Energy Decisions

Putting Competitive Power Markets to the Test

Global Energy independently assessed the benefits of wholesale electric market competition, with the following findings:

1. **Consumers realized $15.1 billion in value from wholesale electric competition in the 1999-2003 study period**. Global Energy calculated the benefits of wholesale competition for the Eastern Interconnection as they occurred. Those results were compared with a simulation of market conditions without the changes in market rules that enabled wholesale competition. Global Energy used its generally available Strategic Planning™ software to replicate the market rules and conditions and calculate consumer benefits. Consumers benefited if the study showed a positive difference between current market conditions and the simulation of the traditional market rules prior to wholesale competition. The results of the analysis are that wholesale customers in the Eastern Interconnection have realized a $15.1 billion benefit due to electricity competition.

2. **Competition dramatically improved the operating efficiency of power plants.** Global Energy conducted an analysis and review of the North American generation fleet operations to assess improvements and efficiencies attributable to competitive forces. This analysis was based on a study period of 1999-2004. Global Energy uncovered strong evidence indicating the electric utility industry has improved its operations and efficiencies, largely due to competitive forces. Some of the power plants with great gains in efficiency had been auctioned off by their prior owners and had historically been relatively poor performers. But the skill of experienced fleet operators, the standardization of procedures and maintenance, and the combined buying power for fuel, equipment, and supplies have produced dramatic improvements in capacity factors and plant performance. The cost savings and energy efficiency resulting from reduced refueling outages, improved capacity factors, and reliability are continuing to provide substantial benefits to consumers.

3. **Opening the PJM Interconnection to more electric supply competitors produced $85.4 million in annualized production cost savings during 2004 for wholesale power customers.** The benefits of expanding the PJM wholesale power market with the addition of Commonwealth Edison (ComEd), American Electric Power (AEP), and Dayton Power & Light (DPL) in 2004, produced $85.4 million in annualized production cost savings for Eastern Interconnection customers. The expansion reduced transmission seams and provided for the entry of new competitors in the Midwest, resulting in a more efficient regional power market. The study showed that PJM wholesale customers weren't the only ones to benefit; rather, wholesale customers throughout the Eastern Interconnection realized a savings. These annual production cost savings should continue year after year.

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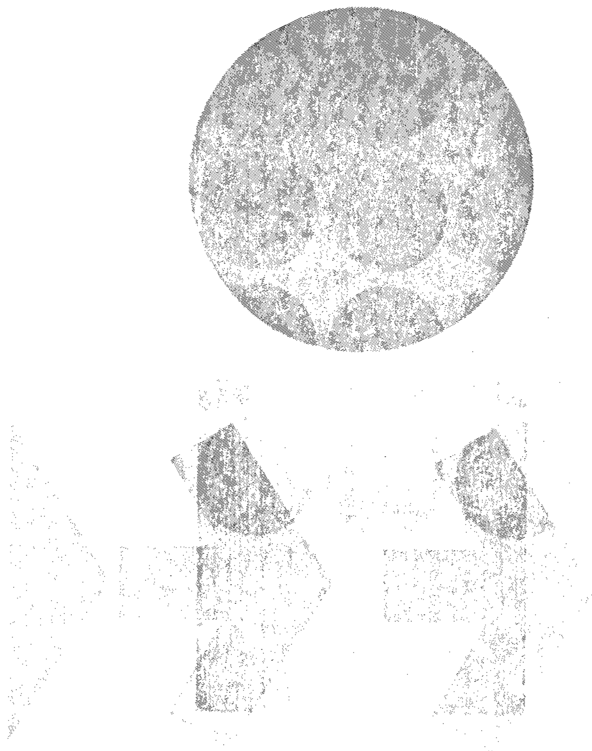


Report Summary

The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies

Report Summary

Introduction

The competitive policies adopted by Congress and implemented by FERC are unequivocally producing consumer benefits.

- Electricity customers in America's Eastern Interconnection power markets saved more than $15.1 billion in energy costs from 1999 to 2003 as a result of competition in wholesale power markets.
- Overall industry improvements in nuclear power plant operations produced enough additional energy to power more than 10 million residential households for one year.[1] Comparable operating efficiency improvements occurred in power plants fueled by coal, which created enough additional energy to power more than 25 million residential households.
- The benefits of expanding the PJM wholesale power market in 2004 provided $85.4 million in annualized production cost savings for Eastern Interconnection wholesale customers through the reduction of transmission seams and entry of new competitors.

Global Energy was asked by a prominent group of electric power generators, marketers, and suppliers to perform an independent analysis of wholesale competition at work today to identify and quantify the existing and foreseeable consumer benefits of competitive electricity markets.[2] This report, titled *Putting Competitive Power Markets to the Test*, is the result of that independent analysis.

Congress created the legislative framework that enabled competitive power markets to meet the nation's growing energy needs. The Public Utility Regulatory Policies Act of 1978 (PURPA) opened the door for competitive power markets with requirements that utilities buy energy from qualifying cogeneration and renewable resource facilities. PURPA demonstrated that power plants could be developed, financed, built, and operated independently of the traditional utility's rate base. Congress expanded wholesale competition in the Energy Policy Act of 1992 (EPAct), creating an entire new class of "exempt wholesale generators" (EWGs) that had more contractual and regulatory flexibility than those under PURPA. The EWGs were authorized to build and operate power plants supported by sales into competitive energy markets, rather than relying upon traditional cost-of-service rate base returns to finance power plant construction. Indeed, the motivation behind these changes was to shift the risk of future power plant construction costs from utility ratepayers to investors in these projects. Ultimately, they became known as "merchant" power plants.

Competitive power markets have flourished by allowing energy companies to make sales using market-based rates (MBR) instead of traditional tariff rates, as allowed by the Federal Power Act (FPA). FERC's implementation of open access and MBR led the initiative to create wholesale power markets that ensured just and reasonable wholesale rates.

FERC has been progressively using its FPA authority to implement and foster wholesale power market competition through a series of orders and market initiatives. FERC's push to establish Regional Transmission Organizations (RTOs) and organized spot markets in order to ensure nondiscriminatory

[1] Based upon average residential customer annual usage of 10,803 kWh per year.
[2] The sponsors of this Global Energy analysis are: BP Energy Company, Constellation Energy, Exelon Corporation, Mirant Corporation, NRG Energy, Inc., PSEG, Reliant Energy Inc., Shell Trading Gas and Power Company, Williams, and Suez Energy North America. The Electric Power Supply Association served as project manager on behalf of the sponsors.

transmission and market access has met with fierce resistance in some parts of the country, namely the Southeast and the Pacific Northwest. Despite that resistance, RTO membership continues to grow. The PJM RTO, which serves the Mid-Atlantic and some Midwestern states, has seen rapid expansion, is integrating its energy markets with those of the Midwest Independent System Operator (ISO), and is collaborating with NYISO and ISO-NE to create a large and growing seamless wholesale power market. The Midwest ISO itself successfully launched its formal market operations on April 1, 2005. Further growth continues to occur with the formation of the Grid West independent transmission organization. Thus far, it has 87 members, has adopted developmental bylaws, and is seating a developmental board of directors.

The growth in the PJM RTO is one aspect Global Energy evaluated for this study because it enables a comparison of consumer benefits in organized RTO markets with traditional markets that do not have the market access afforded by RTOs.

Regional power markets, especially those organized under RTOs now have a proven track record over eight years. However, discussions about the cost and benefits of RTO formation continue among key market participants and regulatory authorities. This study can be viewed as a contributor to that discussion.

Study results show wholesale competition in America's electric power markets is working. When the subject of competition in the electric power industry is discussed in public, often the report card on how competition has performed is told in the context of the California energy crisis or the problems of Enron. No credible study of wholesale competition can be done without recognizing this "elephant in the room." However, the real standard by which competition should be measured encompasses all economic and non-economic factors (e.g., operating efficiencies). Further, the economic comparison should measure today's market prices against the regulated prices that would have occurred, absent any competitive initiatives. Now, 13 years after Congress passed EPAct, it is time to look at how wholesale competition in the electric generation sector of the industry is doing—and whether electricity customers are benefiting from the wholesale competition that the 1992 EPAct envisioned.

The results of Global Energy's analysis of the Eastern Interconnection (an area that comprises two-thirds of the U.S. population and electricity demand, three-quarters of the nation's electricity control areas, and eight of the ten North American Electric Reliability Council's regional councils) are that wholesale competition is working as Congress intended. The FERC regulations and decisions in fostering the creation of regional transmission markets are working to create effective competitive energy markets. Customers are realizing the benefits of wholesale competition in the form of lower wholesale costs for their electric suppliers, more options from renewable resources, better opportunities to manage risk and wider competition from more market participants.

How the Study was performed by Global Energy. The study was conducted by Global Energy using its Global Energy Reference Case, an independent, transparent analysis of electric and natural gas market supply and demand fundamentals updated twice yearly and used widely by credit rating agencies, investment banks, energy companies, utilities and the engineers, consultants and attorneys who serve them. Global Energy used its own independent data sources and market leading **EnerPrise™ Strategic Planning** *powered by MIDAS Gold®* software to perform the analysis. The modeling methodologies and approach are consistent with Global Energy's consulting best practice for cost benefit studies. While the sponsors of the study were involved in helping Global Energy define an appropriate work scope for the project, the assumptions, data, analysis, and conclusions outlined in this report are Global Energy's alone and do not necessarily represent the views of the sponsors.

Consumer Value of Competition

To assess whether wholesale competition is working as Congress and FERC intended, Global Energy assessed the Eastern Interconnection wholesale electric power markets as they occurred in the 1999-2003 study period ("With Wholesale Competition" case). Those results were compared with a simulation, which excluded the regulatory changes, tariff protocols, and market rules that enabled wholesale competition ("Without Wholesale Competition" case).

Global Energy's With Wholesale Competition case divided the Eastern Interconnection into two distinct business sectors. The "Regulated" sector comprised traditional regulated utilities, which have an obligation to serve native load retail customers. The "Competitive" sector comprised the exempt wholesale or merchant generating units, which are at risk, as they are not allowed a regulated return. In this analysis, the sole source of income for the Competitive sector is energy and capacity sales to the Regulated sector.

The Without Wholesale Competition case calculated the consumer cost had the market remained as traditional, vertically integrated utilities operating in a regulated environment without wholesale competition. Global Energy used its generally available Strategic Planning software to replicate the market rules and conditions and to calculate the customer benefits. Customers benefited if the study showed a positive difference (lower costs) between current market conditions and the simulation of the traditional utility market prior to wholesale competition. The results of the analysis are that consumers in the Eastern Interconnection have realized a $15.1 billion benefit due to wholesale competition over what they would have realized under the traditional regulated utility environment.

The valuation method Global Energy employed in the analysis is the minimization of operating expenses for the regulated utility buyer. Under traditional utility cost of service regulation, the minimization of operating expenses provides the greatest benefit to the retail customer. Global Energy assumed all operating expenses were fully recovered in the base revenues of the regulated utility sector. The operating expenses include fuel expenses, energy and capacity purchases from the Competitive market sector, variable O&M, fixed O&M, depreciation, taxes, and operating income.[3]

[3] For the Regulated Sector, Operating Income is defined as rate base times a "fair and reasonable" allowed return on rate base of 8.5 percent.

Figure RS-1 illustrates the Regulated sector's additional operating expenses for the Without Wholesale Competition case. Figure RS-2 illustrates the Regulated sector purchasing energy and capacity from the Competitive sector for the With Wholesale Competition case. In both cases, Global Energy calculated the Regulated sector's fuel and variable O&M expense for serving the Eastern Interconnection load as these expenses change between the two cases.

Figure RS-1
Without Wholesale Competition

Regulated Sector

Operating Expenses

Fuel

+ Variable O&M

+ Fixed O&M

+ Depreciation

+ Property Taxes

+ Income Taxes

+ Operating Income

New Generation Built by Regulated Sector

Figure RS-2
With Wholesale Competition

Regulated Sector

Operating Expenses

Fuel

+ Variable O&M

+ Energy Purchases

+ Capacity Purchases

Competitive Sector Revenues

SOURCE: Global Energy.

Defining the Two Cases

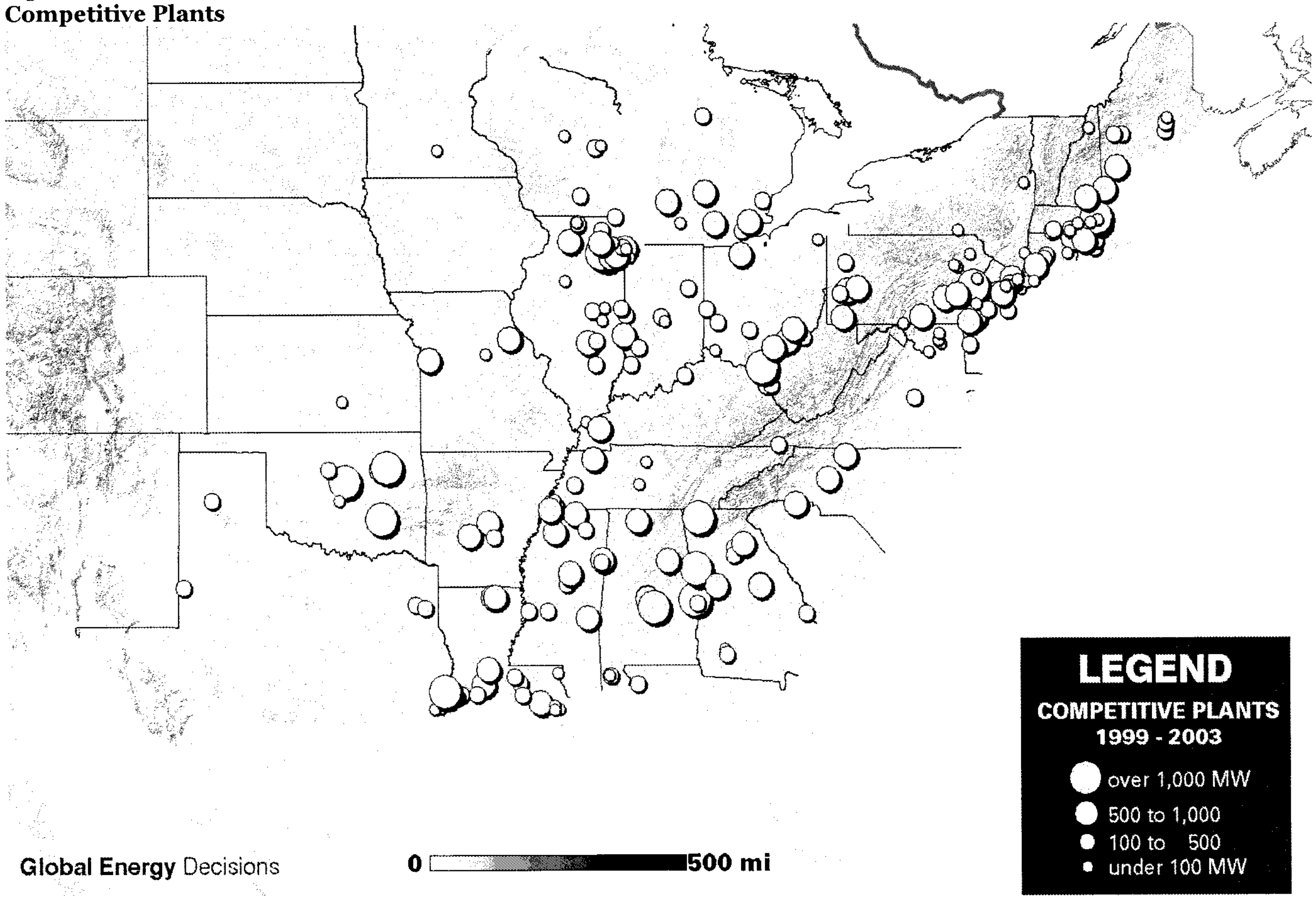
The With Wholesale Competition case differs from the Without Wholesale Competition case in three main areas.

1. Competitive Plants
   - In the Without Wholesale Competition case, it is assumed that no competitive or merchant plants would have been built; however, qualifying facilities built pursuant to PURPA requirements were included.
2. Regional Transmission Organization (RTO)
   - In the Without Wholesale Competition case, it is assumed that FERC Orders 888 and 2000 never occurred and that RTOs were not formed. RTO transmission rates are replaced with pancaked transmission rates, which traditionally existed in these areas.
3. Market-Based Rates for Wholesale Energy
   - In the Without Wholesale Competition case, it is assumed that marginal cost-based contracts replace market-based wholesale energy.

Competitive Power Plant Development (With Wholesale Competition Case)

The Competitive sector comprises 88,686 MW of generation added over the five-year study period. The mix of generation is 56 percent combined cycle units (50,106 MW) and 44 percent simple cycle units (38,580 MW). For this analysis, Global Energy estimates that the Competitive sector sold $13.7 billion worth of energy and capacity to the Regulated sector. Figure RS-3 shows the dispersion of competitive plants added in the Eastern Interconnection during the study period.

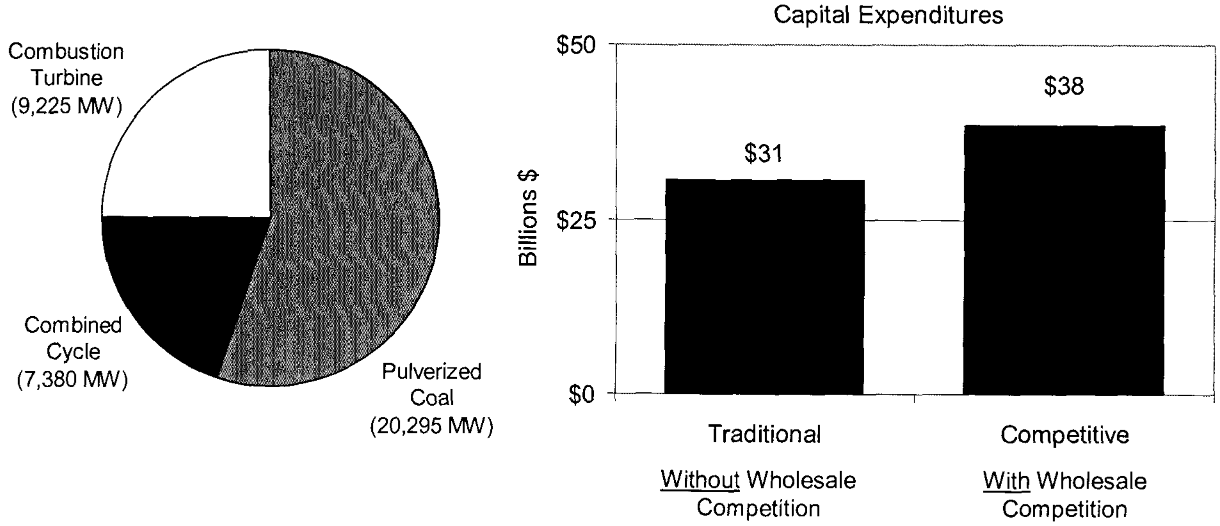
Figure RS-3
Competitive Plants



Traditional Power Plant Development (Without Wholesale Competition Case)

In the Without Wholesale Competition case, Global Energy calculated the level and mix of new generation that utilities would have built to satisfy minimum reserve margins and consumer energy requirements. That electric supply portfolio would have consisted of 55 percent pulverized coal, 20 percent combined cycle, and 25 percent combustion turbines. As shown in Figure RS-4, capital spent by the Regulated sector is $7 billion less than was spent by the Competitive sector.

Figure RS-4
Traditional Generation Supply Portfolio; 1999-2003



SOURCE: Global Energy.

Comparing the Two Cases

The five-year consumer benefit of the With Wholesale Competition case versus the Without Wholesale Competition case was $15.1 billion. A comparative expense breakdown is shown in Table RS-1.

Table RS-1
Consumer Benefit; 1999-2003: Cost of Service Environment vs. Competitive Market

	Without Wholesale Competition	With Wholesale Competition	Consumer Benefit
Fuel (Fossil and Nuclear)	160,979	156,971	4,008
+ Variable O&M	21,902	19,515	2,387
+ Competitive Energy Purchase	-	11,495	(11,495)
+ Competitive Capacity Value	-	2,220	(2,220)
+ Fixed O&M	7,610	-	7,610
+ Depreciation	2,670	-	2,670
+ Property Taxes	931	-	931
+ Income Taxes	3,289	-	3,289
+ Operating Income	7,960	-	7,960
Operating Expenses (millions $)	**205,341**	**190,201**	**15,140**

SOURCE: Global Energy.

The With Wholesale Competition case does not reflect expenses and returns associated with existing utility infrastructure. The Without Wholesale Competition case includes expenses and returns for new generation constructed by the Regulated sector. In essence, Global Energy is quantifying the cost and risk transfer of power plant construction between the two sectors (Competitive and Regulated). Table RS-2 provides a description of each variable of the operating statement.

Table RS-2
Operating Statement Variable Descriptions

	Without Wholesale Competition	With Wholesale Competition
Fuel (Fossil and Nuclear)	Cost of fossil and nuclear fuel burned by existing utility infrastructure. This line item includes all plants (regardless of ownership) built prior to 1999, new rate base plants built in the 1999-2003 study period, and the 36,900 MW of traditional plants identified in Figure RS-4.	Cost of fossil and nuclear fuel burned by existing utility infrastructure. This line item includes all plants (regardless of ownership) built prior to 1999, plus new rate base plants built in the 1999-2003 study period. The 88,686 MW of competitive plants identified in Figure RS-3 are excluded from this line item.
Variable O&M	This line item includes all plants (regardless of ownership) built prior to 1999, new rate base plants built in the 1999-2003 study period, and the 36,900 MW of traditional plants identified in Figure RS-4.	This line item includes all plants (regardless of ownership) built prior to 1999, plus new rate base plants built in the 1999-2003 study period. The 88,686 MW of competitive plants identified in Figure RS-3 are excluded from this line item.
Competitive Energy Purchase	Not applicable. In this case there are no competitive plants.	Cost of energy purchased from the competitive plants identified in Figure RS-3.
Competitive Capacity Value		Cost of capacity purchased from the competitive plants identified in Figure RS-3.
Fixed O&M Depreciation Property Taxes Income Taxes	These expenses are associated with the 36,900 MW of traditional plants constructed in the study period.	Expenses were not included for existing utility infrastructure because it would be the same for with and without cases.
Operating Income	This line item is the operating income of the 36,900 MW of traditional plants constructed in the study period. The operating income is calculated as rate base times a return on rate base of 8.5 percent.	Operating income was not included for existing utility infrastructure because it would be the same for with and without cases.

SOURCE: Global Energy.

Summary - Consumer Value of Competition

Electricity customers in the Eastern Interconnection benefited by more than $15.1 billion over the five-year study period, in contrast to what they would have been expected to pay under more traditional regulated markets without wholesale competition. Had competitive generators and power suppliers not emerged, regulated utilities would have been required to build rate base generating assets and incur the costs to run them. Under wholesale competition, competitive energy suppliers take the risk of building and operating the power plants and selling the energy output to utility and other wholesale or large industrial customers.

These regulated utilities paid the competitive merchant sector more than $13.7 billion for the energy and capacity in the study period. However, in the Without Wholesale Competition alternative, there would have been an additional $28.9 billion in operating expenses. Thus, the consumer benefit is $15.1 billion when all the costs, including the cost to buy merchant power, were considered over the more traditional process of allowing utilities to build the assets and incur the increased cost of fuel, O&M, depreciation, taxes, and operating income to run them.

Wholesale Market Competition Dramatically Improved the Efficiency of Power Plants

Global Energy Decisions conducted an analysis and review of the North American generation fleet operations to assess improvements and efficiencies attributable to competitive forces. This analysis was based on a study period of 1999-2004. Global Energy uncovered strong evidence indicating the electric utility industry has improved its operations and efficiencies, largely due to competitive forces. Some of the power plants with great gains in efficiency had been auctioned off by their prior owners as relatively poor performers. But the skill of experienced fleet operators, the standardization of procedures and maintenance, and the combined buying power for fuel, equipment and supplies have produced dramatic improvements in capacity factors and plant performance. The cost savings and energy efficiency resulting from reduced refueling outages, improved load factors and reliability continues to substantially benefit consumers.

The analysis focused on the nuclear and coal-powered generating units for traditional and competitive operators. Traditional operators are best defined as investor-owned utilities, municipalities, and cooperatives that are subject to retail rate regulation. Competitive operators are best defined as independent power producers and other generators that are not subject to retail rate regulation.

Nuclear Generation

Nuclear generation makes up 10 percent of the U.S. installed power generation capacity by fuel and about 20 percent of actual net generation each year.[4] Electric industry restructuring led to consolidation of nuclear operations through the purchase and sale of nuclear facilities across the country by experienced nuclear fleet operators such as Exelon and Entergy. Global Energy's analysis focused on a view of nuclear generation based on the classifications of plants owned and operated by IOUs and competitive plants that were sold and purchased.

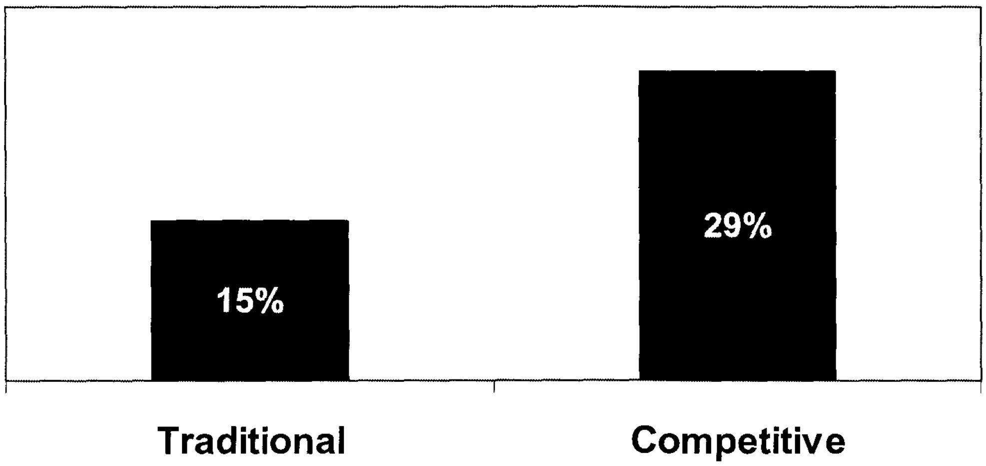
A number of nuclear facilities prior to wholesale competition were considered "troubled" and in danger of being shut down and decommissioned. Under competitive market conditions, many of these nuclear power plants have been sold, or their operation was contracted out to experienced nuclear fleet operators on a merchant basis. Consumers have benefited from the continued operation of these units, in addition to the improvements in operation and efficiencies.

[4] Global Energy Reference Case.

Nuclear Plant Refueling Outage Time Reduced

Global Energy conducted an analysis and review of the (Nuclear Regulatory Commission (NRC) daily unit outage information. Competitive units experienced a 29 percent reduction in the length of refueling outages since 1999. Figure RS-5 depicts the percentage improvement.

Figure RS-5
Percent Reduction in Length of Refueling Outages since 1999



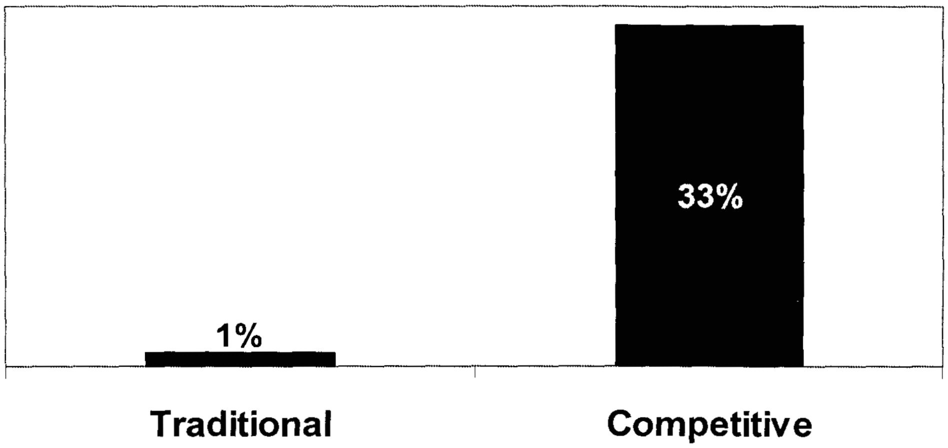
SOURCE: Global Energy.

Overall, the industry experienced a decline in total refueling outage days of nearly a year. Competition and industry restructuring have positively influenced the management of nuclear facilities through competitive pricing.

Nuclear Plant Operations & Maintenance Expenses Lowered

Global Energy conducted an analysis of the nuclear facilities' total fixed and variable operations and maintenance expenses. Competitive units experienced a 33 percent reduction in O&M expense on a $/MWh over 1999, as displayed in Figure RS-6. Competitive facilities have consistently reduced expenses over the study period.

Figure RS-6
Nuclear Plant O&M Reductions since 1999



SOURCE: Global Energy.

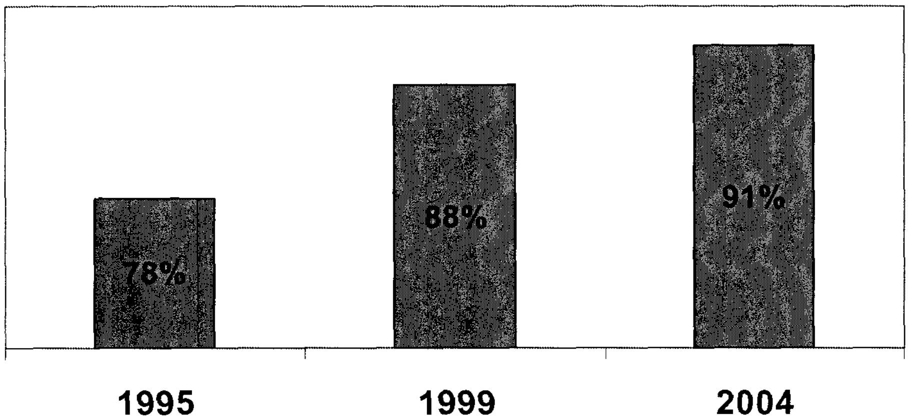
Note that in 1999, competitive nuclear facilities were experiencing costs of almost $15/MWh whereas traditional facilities' costs were around $10/MWh. The disparity is largely due to the fact that the competitive fleet of nuclear plants had a higher cost structure prior to their transfer to, or acquisition by, the Competitive sector. In 1999, the competitive nuclear facilities were relatively poor performers in the nuclear industry in regard to operating costs. However, by 2004, the skill of large scale experienced nuclear fleet operators; the standardization of procedures and maintenance; and the combined buying power for fuel, equipment, and supplies dramatically improved plant costs and performance. Now, the "poor performers" are indistinguishable from traditional facilities, as both have operating and maintenance costs of approximately $10/MWh.

Nuclear Plant Capacity Factors Increased

Nuclear units have relatively low variable costs and are, thus, low dispatch-cost generating facilities. As such, a measurable benefit is a high capacity factor. Prior to competitive forces shifting the management and operation of nuclear facilities to more experienced operators focused on improving plant performance in a competitive market environment, nuclear facilities were often operating at "sub-optimal" levels in 1995. Since 1995, the nuclear units have displayed continual improvement. According to Nuclear Energy Institute (NEI), nuclear plants had record output and stable costs in 2004. U.S. plants generated a record 786.5 million MWh in 2004, breaking the 2002 record of 780 million MWh. NEI's figures put the 2004 average net capacity factor at 90.6 percent, trailing only the 91.9 percent achieved in 2002 and the 90.7 percent in 2001. The slightly lower capacity factor, despite the higher output, occurred because nuclear operators nationwide have been uprating their units.

The nuclear industry experienced a 17 percent increase in capacity factors since 1995. Global Energy also found that since 1995 the increase in capacity factor resulted in enough energy to power more than 10 million residential households for one year.[5] Figure RS-7 depicts the overall capacity factor for the industry.

Figure RS-7
Nuclear Plant Capacity Factors; 1995-2004



SOURCE: Global Energy.

Coal Generation

Coal-fueled generation is the most predominant type of generating resource in the United States. Even with the additional natural gas-fueled generation, coal still represented 51 percent of total net generation in 2004.

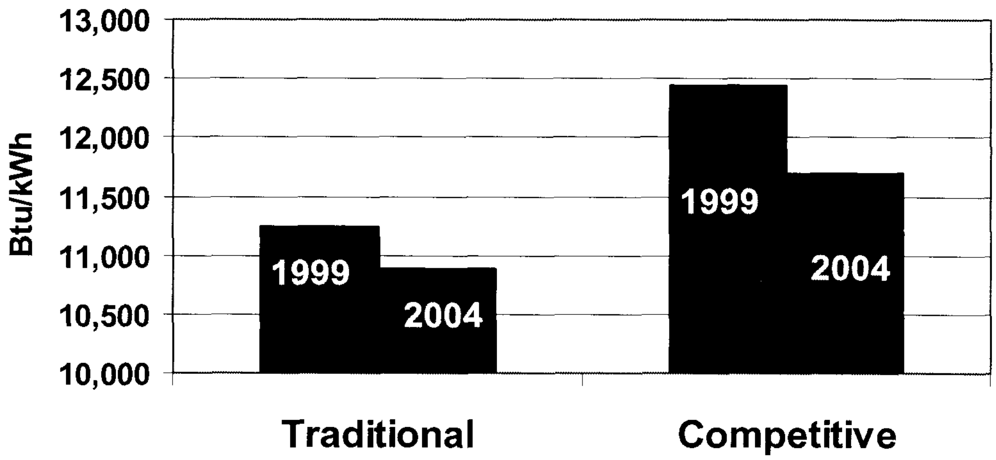
To identify how competitive pressures affected coal generation Global Energy conducted an analysis of coal-fueled generation based on a classification of traditional utility and competitive industry structures. Traditional utility structures represent generating facilities owned by investor-owned utilities, municipalities, and cooperatives that are subject to retail rate regulation. Competitive industry structures represent generating facilities owned by independent power producers that are not subject to retail rate regulation.

[5] Based on average residential customer annual usage of 10,803 kWh per year.

Coal Heat Rates Improved

Heat rate is a measurement of a generating station's thermal efficiency and is usually expressed in Btu/kWh; the lower the Btu/kWh, the higher the efficiency of the unit. Figure RS-8 shows that competitive units improved heat rates by 6 percent, while traditional units improved 3 percent since 1999. Overall, industry-wide heat rates for coal plants improved 4 percent during the study period. The traditional units consist of a more modern fleet, while the competitive units are older, less-efficient performers before they were transferred or sold by the prior owners. Nevertheless, the new competitive owners were able to achieve a 6 percent heat rate improvement. The environmental impact of the heat rate improvement is 12.3 million fewer tons of coal burned each year for the competitive fleet.

Figure RS-8
Coal Heat Rate Improvements



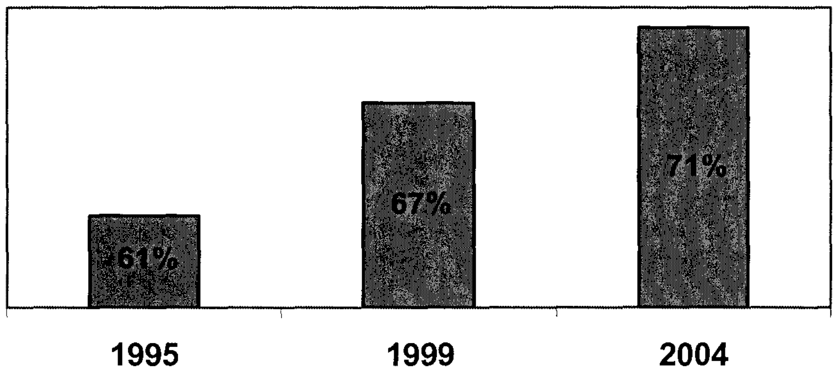
SOURCE: Global Energy.

Competitive pressures have compelled traditional utilities to maintain costs, while improving their overall efficiency. Consumers benefit from the overall improvement in efficiencies of coal generation regardless of whether they are related to traditional or competitive facilities.

Coal Plant Capacity Factors Increased

As with nuclear plants, the fleet of coal plants saw an improvement in capacity factors in the decade between 1995 and 2004. Figure RS-9 demonstrates that coal-fueled power plant capacity factors increased overall by 16 percent, from 61 percent to 71 percent. Because there are three times as many MW of coal-fueled capacity as there are MW of nuclear plant capacity, this increase had the effect of making at least another 50,000 MW of effective generating capacity available for dispatch in 2004 as there was prior to 1995. Furthermore, the increase in capacity factors for coal-based plants was enough electricity to power 25 million residential households for a year.

Figure RS-9
Coal Plant Capacity Factors; 1995-2004

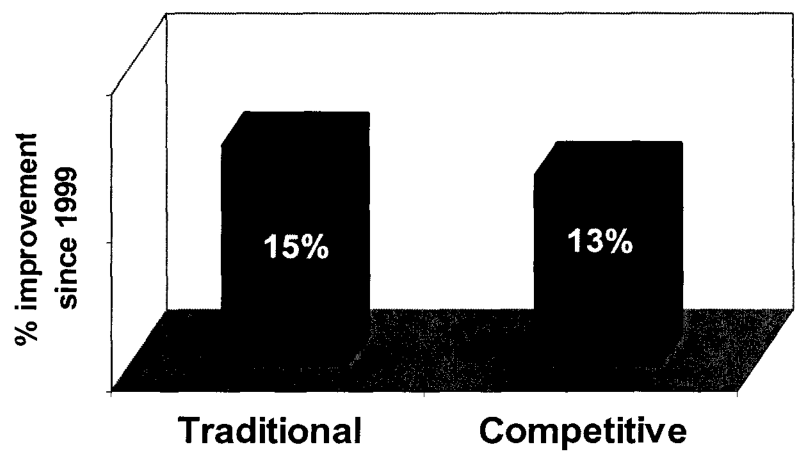


SOURCE: Global Energy.

Coal Operation & Maintenance Expenses Declined

Global Energy conducted an analysis of the coal fleet's operation and maintenance expenses to ascertain any influences of competition on these costs. Overall, coal O&M expense has declined when adjusted for inflation. Figure RS-10 shows that Competitive facilities improved 13 percent, while Traditional experienced a 15 percent improvement.

Figure RS-10
Coal O&M Improvements



SOURCE: Global Energy.

Reductions in the operating costs of base load, lower-cost plants, such as coal, benefit consumers through lower purchased power costs and regulated entities' ability to manage costs such that increases in rates are not necessary.

Summary - Improved the Efficiency of Power Plants

The empirical evidence indicates that the electric utility industry has improved its operations and efficiencies. Competitive utility structures are at the forefront of these improvements, either directly or indirectly, as demonstrated by the dramatic change in operating performance. Nuclear power plant performance improvements, in particular, have turned these plants, once considered to be an albatross around the neck of utilities, into star performers for the Regulated and Competitive plant operators skilled in running a fleet of nuclear plants.

Opening PJM to More Electric Supply Competitors Produced $85.4 Million in Production Cost Savings for Wholesale Power Customers

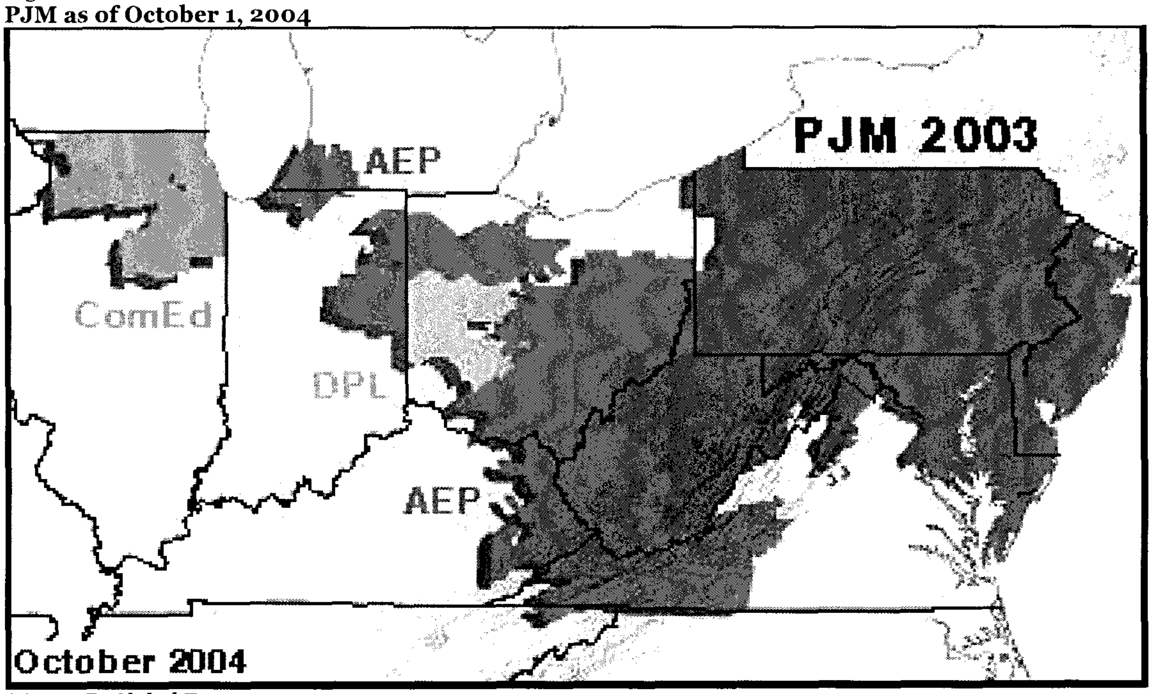
To test the impact of competition in expanded wholesale power markets, Global Energy assessed the impacts of integrating Commonwealth Edison (ComEd), American Electric Power (AEP) and Dayton Power & Light (DPL) into the PJM regional power market. The results of the analysis were that the benefits of expanding the PJM wholesale power market in 2004 produced $85.4 million in annualized production cost savings to wholesale customers in the Eastern Interconnection.

These savings were achieved through reduced transmission barriers, or seams, and the entry of new competitors to the market. FERC decisions have enabled additional market participants such as Exelon's ComEd, AEP, and DPL to join the PJM market. The results of competitive forces at work was immediate, sending price signals throughout the broader regional power markets where power buyers searching for the lowest-cost supply available found them from a now wider universe of generators, marketers and suppliers.

PJM Case Study

The integration of ComEd, AEP and DPL resulted in significant growth in the PJM market. In 2003, PJM comprised 76,000 MW of installed generating capacity and a peak load of 63,000 MW. By October of 2004, PJM comprised 144,000 MW of installed capacity and approximately 107,800 MW of peak load.

Figure RS-11
PJM as of October 1, 2004



SOURCE: Global Energy.

According to an internal analysis performed by PJM of the locational marginal prices (LMPs) in its energy spot markets, the impact of supply and demand fundamentals on market behavior from 2003 to 2004 translated into lower power prices for PJM. While average PJM power prices actually increased by 7.5 percent from 2003 to 2004, PJM showed that the increase was primarily a result of higher fuel prices. PJM performed a fuel adjustment of PJM prices and determined that fuel-adjusted PJM power prices actually declined by 4.2 percent from 2003 to 2004.

Table RS-3
PJM Load-weighted LMP ($ per MWh); 2003 to 2004

	2003	2004	Change
Average LMP	$41.23	$44.34	7.5%
Fuel Adjusted LMP	$41.23	$39.49	-4.2%

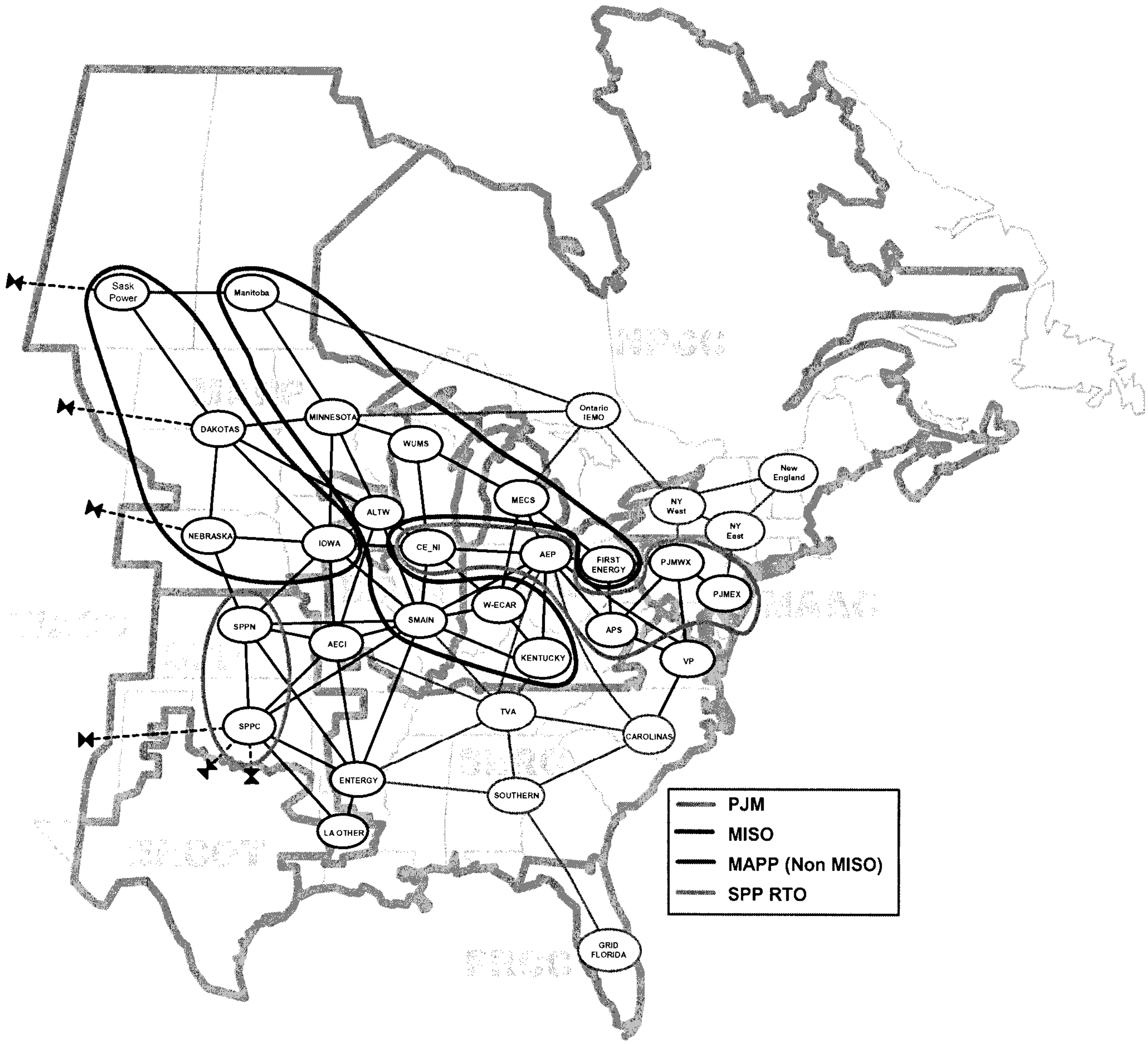
SOURCE: PJM.

Global Energy's PJM Case Study Approach

For this case study, Global Energy modeled the Eastern Interconnection power market to test PJM's conclusions; account for all price determinants not directly related to the integration; and to quantify the impacts associated with the integration of ComEd, AEP, and DPL supply and demand with that of PJM. Global Energy's approach was to analyze and quantify the impact of reducing the seams, in the form of pancaked wheeling charges, between the ComEd, AEP, DPL, and PJM energy markets. By isolating pancaked wheeling charges in its analysis, Global Energy captured the primary structural change to ComEd, AEP, DPL, and PJM's energy market supply and demand.

Global Energy employed a production cost savings model using its **EnerPrise™ Market Analytics** module, which measures production costs, such as fuel and operations and maintenance costs. The study compared the production costs of a "Competition" case, which simulated PJM as it was in 2004, and compared these costs with a "Without Competition" case that would have existed in 2004 if ComEd, AEP, and DPL had not joined PJM. Because Dominion Resources in Virginia did not join PJM until January 1, 2005, it was not included in this analysis.

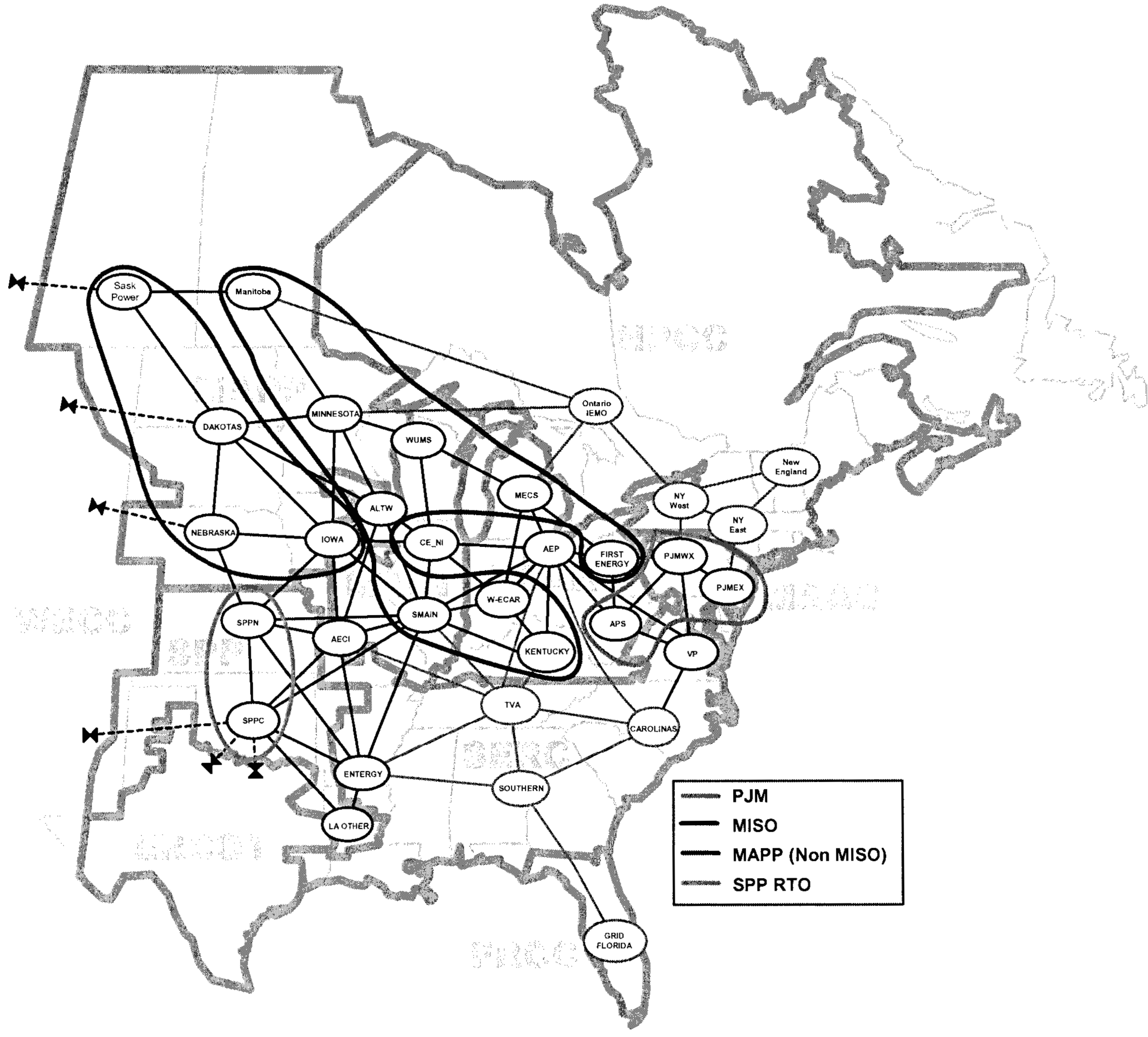
Figure RS-12
Competition Case Market Topology as of October 1, 2004



SOURCE: Global Energy.

In the Without Competition case, the market topology is similar to the Competition case except that ComEd (represented by the CE_NI zone) and AEP and DPL (both represented by the AEP zone) are modeled outside the PJM RTO and pancaked wheeling between the zones is not eliminated.

Figure RS-13
No Competition Case Market Topology for 2004



SOURCE: Global Energy.

Other Potential Benefits of PJM Integration

In addition to the integration of supply and demand in the wholesale energy market, brought about by the reduction of transmission seams between market areas, there are other significant benefits to RTO membership and the integration of energy markets and services in general that were not considered in this study. For example, AEP and DPL are now integrated with APS in a single spinning reserves market.

For regulation services, ComEd, AEP, DPL, and APS are all members of PJM's integrated Western Zone. PJM also coordinates generation and transmission maintenance for the entire RTO, as well as Available Transmission Capacity (ATC). These and other potential benefits are not captured in this analysis.

Summary - Opening PJM to More Electric Supply Competitors Produced Savings

Global Energy's analysis supports PJM's conclusion that, in 2004, changes in supply and demand fundamentals resulted in lower PJM prices in 2004 than 2003. Global Energy quantified the production cost savings associated with the reduction of seams between these ComEd, AEP, DPL, and PJM's energy markets at approximately $29.5 million for PJM in 2004 and $36.4 million for the Eastern Interconnection. Because these savings are based on the actual integration schedule for ComEd (May 2004) and AEP/DPL (October 2004), they represent savings for a partial year of integration in 2004. In order to quantify the benefits associated with a full year of integration, Global Energy performed the analysis as if ComEd, AEP, and DPL joined PJM on January 1, 2004. The estimated annualized production cost savings for PJM and the Eastern Interconnection were $69.8 million and $85.4 million, respectively.

Table RS-4
Estimated Benefits of Energy Market Integration in 2004

	2004 Production Cost Savings	
Market Area	Savings based on 2004 PJM Integration Timeline (ComEd in May 2004 and AEP/DPL in October 2004	Annualized Savings (Simulates Integration of ComEd, AEP, DPL on January 1, 2004
PJM	$29.5 MM	$69.8 MM
Eastern Interconnect	$36.4 MM	$85.4 MM

SOURCE: Global Energy.

RTO formation has opened the doors to broad market access for customers, not only to merchant generators and suppliers in a more competitive market environment, but also increasingly to renewable energy from wind and other sources. The annual production cost savings for the PJM expansion will repeat year after year.

Conclusion

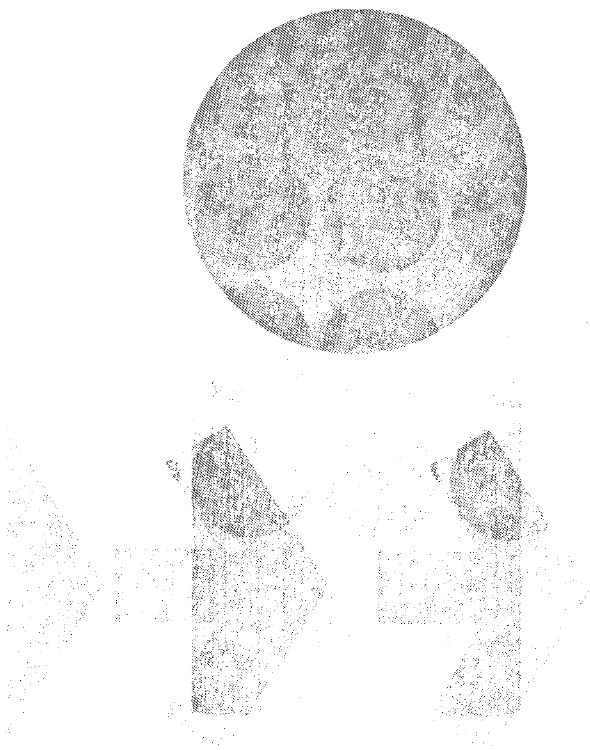
Wholesale competition is lowering the costs of providing electric energy to retail customers, just as Congress, FERC, state regulatory commissions, and ratepayer advocates intended. The effect of competition at work has been to shift the expense and risk of building power plants from utility customers to the competitive power plant owner and operator and the competitive power supplier, generally. Electricity customers benefited by more than $15.1 billion over the five-year study period, compared with what they would have been expected to pay under a more traditional utility environment without competition. Had competitive generators and power suppliers not emerged, regulated utilities would have been required to build rate base generating assets and incur the costs to run them. Under wholesale competition, merchant energy suppliers take the risk of building and operating the power plants and selling the energy output to utility players.

These regulated utilities paid the competitive merchant sector more than $13.7 billion for the energy and capacity in the study period. However, in the Without Wholesale Competition alternative, there would have been an additional $28.9 billion in operating expenses. Thus, the consumer benefited by more than $15.1 billion when all the costs, including the cost to buy merchant power, were considered over the more traditional process of allowing utilities to build the assets and incur the increased cost of fuel, O&M, depreciation, taxes, and operating income to run them.

Competitive wholesale energy markets have made substantial progress in giving energy consumers the benefits of competition in lower wholesale energy prices than otherwise would have been available, as well as improved efficiency and better reliability. The change in operating performance between traditional regulated utility power plant performance and competitive generator performance has been dramatic. Nuclear power plant performance improvements, in particular, have turned these plants—once thought to be an albatross around the neck of utilities—into star performers for the utility and competitive plant operators skilled in running a fleet of nuclear plants. Similar performance improvements have been seen in coal-fueled generation, as well.

RTO formation has opened the doors to broad market access for customers, not only to merchant generators and suppliers in a more competitive market environment, but also increasingly to renewable energy from wind and other sources.

Putting competitive power markets to the test resulted in savings of $15.1 billion for consumers over the five-year study period (1993-2003). And given that consumer benefits are tied to merchant power plant investment, the savings will continue to accumulate into the future.



Section One
Consumer Value of Competition

1
Consumer Value of Competition

Introduction

To assess whether wholesale competition is working as Congress and FERC intended, Global Energy assessed the Eastern Interconnection wholesale electric power markets as they occurred in the 1999-2003 study period ("With Wholesale Competition" case). Those results were compared to a simulation, which excluded the regulatory changes, tariff protocols and market rules that enabled wholesale competition ("Without Wholesale Competition" case). Refer to Appendix A for Global Energy's discussion of wholesale competition.

Global Energy's With Wholesale Competition case divided the Eastern Interconnection into two distinct business sectors. The "Regulated" sector is comprised of traditional regulated utilities, which have an obligation to serve native load retail customers. The "Competitive" sector is comprised of the exempt wholesale or merchant generating units, which are at risk as they are not allowed a regulated return. In this analysis, the sole source of income for the Competitive sector is energy and capacity sales to the Regulated sector.

The Without Wholesale Competition case calculated the consumer cost had the market remained as traditional, vertically integrated utilities operating in a regulated environment without wholesale competition. Global Energy used its generally available Strategic Planning™ software to replicate the market rules and conditions and to calculate the customer benefits. Customers benefited if the study showed a positive difference (lower costs) between current market conditions and the simulation of the traditional utility market prior to wholesale competition. The results of the analysis are that consumers in the Eastern Interconnection have realized a $15.1 billion consumer benefit due to wholesale competition over what they would have realized under the traditional regulated utility environment. Refer to Appendix B for Strategic Planning model overview.

The market rules in effect during the study period included the following FERC Competitive Power Market Initiatives:

- Order 888. The wholesale electricity landscape changed when FERC issued its order 888 in 1996, requiring public utilities that owned, operated or controlled transmission assets to file open access tariffs, opening their transmission system to competition on non-discriminatory basis. Order 888 also provided for the full recovery of stranded costs. While FERC has not required the formation of ISOs, it has provided guidelines for their creation for utilities that sought a more effective means for the operational unbundling of transmission and generation.
- FERC introduced the ISO as an independent organization that was responsible for providing non-discriminatory access to the transmission system and ancillary services; ensuring the short-term reliability of grid operations; controlling interconnected transmission facilities within its region; identifying and taking operational action to relieve transmission constraints; and coordinating with neighboring control areas.
- Order 889 mandating each utility to establish or participate in an Open Access Same Time Information System (OASIS) to share information about available transmission capacity followed order 888.
- Order 2000. In December 1999, FERC issued its Order 2000, requiring public utilities that owned, operated or controlled interstate transmission facilities to make regulatory filing of their intent to

form or participate in a regional transmission organization (RTO). FERC envisioned RTO formation and development as the tool to promote efficiency in the wholesale electricity markets and eventually lower costs for wholesale and retail consumers of electricity, while maintaining reliable service. As such, a regional transmission organization would be responsible for improving transmission grid management efficiency, improving grid reliability, and preventing discriminatory transmission practices.

The valuation method Global Energy employed in the analysis is the minimization of operating expenses for the regulated utility sector. Under traditional utility cost of service regulation, the minimization of operating expenses provides the greatest benefit to the retail customer. Global Energy assumed all operating expenses were fully recovered in the base revenues of the regulated utility sector. The operating expenses include fuel expenses, energy and capacity purchases from the Competitive sector, variable O&M, fixed O&M, depreciation, taxes, and operating income.[1]

Global Energy used a fundamentals-based methodology to perform the analysis, modeling the details of unit characteristics, hourly demand, fuel prices, and transmission. Using its own Energy Velocity data source and market-leading Strategic Planning software, the modeling methodologies and approach are consistent with Global Energy's consulting best practice for cost benefit studies.

The Consumer Value of Competition analysis was performed in three distinct progressive steps.

1. **With Wholesale Competition Simulation.** The Strategic Planning model was calibrated so unit performance, market prices, and power flows were similar to observed market conditions for the 1999-2003 study period. Once calibrated, the value of the energy and capacity sales made by the Competitive sector to the Traditional sector was included in a cost of service calculation.
2. **Without Wholesale Competition Simulation.** For the Without Wholesale Competition Case, Global Energy modeled how the Eastern Interconnection most likely would have looked had Congress not passed the National Energy Policy Act of 1992 (EPAct). In this simulation, there are no competitive power plants, no regional transmission organizations, and wholesale energy is exchanged at marginal cost based contracts rather than wholesale market-based pricing.
3. **Result Comparison.** To compare the two cases, Global Energy utilized the pro forma financial and rate making capabilities of its Strategic Planning software, modeling cost of service of the Regulated sector for each case. The case with the lowest cost of service provided the greatest consumer benefit.

Market Topology

Global Energy divided the Eastern Interconnection into the market areas illustrated in Figure 1-1. As shown, the 29 market areas traverse eight NERC regional councils—namely FRCC, MAPP, MAIN, NPCC, ECAR, MAAC, SERC and SPP. Within the market areas it was assumed that there were no significant transmission constraints and therefore no transmission costs for moving power within each transmission market zone. Hourly loads were assigned to the market areas based on the FERC filings of the utilities located in each area.

[1] For the Regulated Sector, Operating Income is defined as rate base times a "fair and reasonable" allowed return on rate base of 8.5 percent.

Figure 1-1
Market Configuration

SOURCE: Global Energy.

Calibration

Global Energy used a fundamentals-based approach to calibrate unit performance, market prices, and power flows. Based on its proprietary Strategic Planning system—a proven data management and production simulation model—Global Energy simulated the operation of each generating unit of the Eastern Interconnection. Strategic Planning is a sophisticated state-of-the-art, multi-area, chronological production/market simulation model. Included with each Strategic Planning simulation are pro forma financials, providing users with a complete enterprise-wide solution.

For each region, Strategic Planning considered:

- Individual generating unit characteristics including heat rates, variable O&M, fixed O&M, and other technical characteristics;
- Transmission line interconnections, ratings, and wheeling rates;
- Resource additions and retirements;
- Nuclear unit outages and refuelings;
- Hourly loads for each utility or load serving entity in the region; and
- The cost of fuels that supply the plants.

Strategic Planning simulated the operation of individual generators, utilities, and control areas to meet fluctuating loads within the region with hourly detail. The model is based on a zonal approach where market areas (zones) are delineated by critical transmission constraints. The simulation is based on a mathematical function that performs economic power exchanges across zones until all eligible economic exchanges have been made.

Global Energy's calibration methodology was to:

- Benchmark the model against observed prime mover output within the market zones;
- Benchmark the model against observed market prices; and
- Benchmark the model against observed power flows.

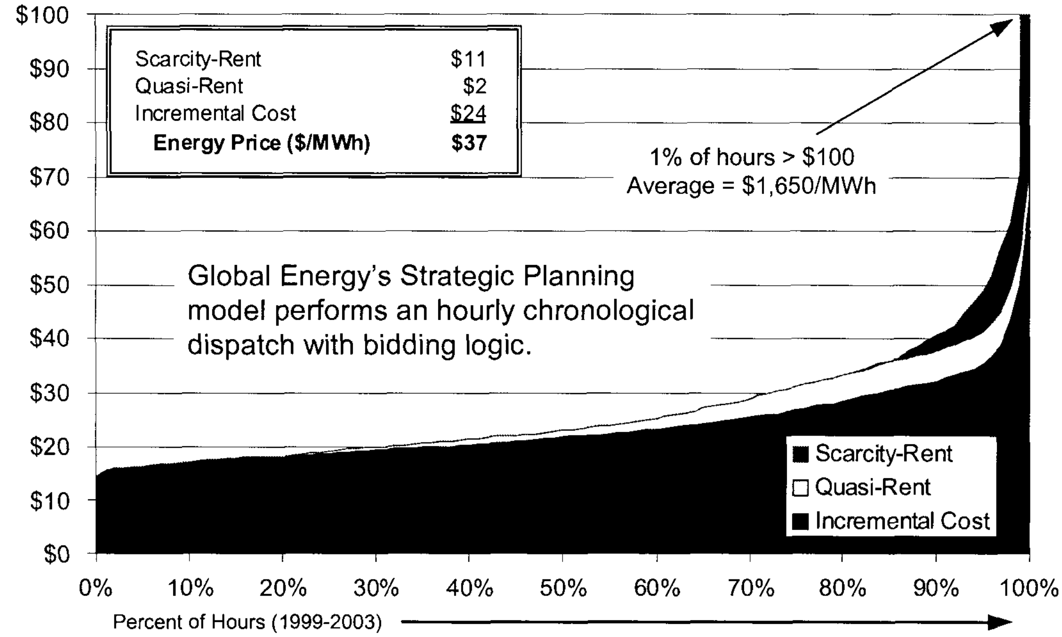
Bidding Behavior

To capture the unique bidding behavior of the energy market, Strategic Planning utilizes a dynamic bid adder algorithm that considers supply/demand conditions and technology type when submitting a bid. Figure 1-2 represents the various components of the Entergy 7x24 market clearing price from 1999-2003. Overall, the average price was $37/MWh. In replicating the bidding behavior of the Entergy power market, Global Energy captured the three key market price elements of:

- **Incremental Cost.** Includes fuel price, heat rate, and variable O&M. Under rational bidding, the incremental cost serves as a generator's minimum bid. As illustrated in Figure 1-2, the incremental cost component for the Entergy 7x24 market averaged $24/MWh.
- **Quasi-Rents Component.** Rent component added to the incremental cost to recover start-up costs, minimum-run costs, and a portion of fixed operating costs and financial expense. For the Entergy 7x24 market, the quasi-rents component averaged $2/MWh.
- **Scarcity-Rents Component.** Rent component added to the incremental cost and quasi-rent. As demand increases, there are fewer alternative sources of generation, providing the higher cost generators an opportunity to bid above their variable cost. For the Entergy 7x24 market, the scarcity component averaged $11/MWh.

Refer to Appendix B for more on the Strategic Planning bidding behavior.

Figure 1-2
Entergy 7x24 Daily Market Bid Components; 1999-2003

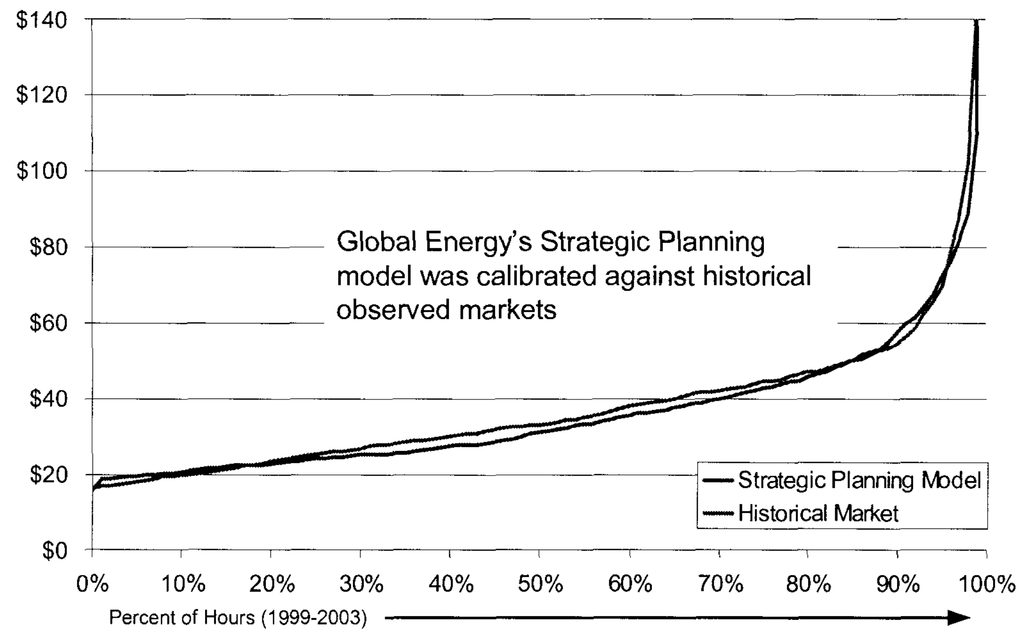


SOURCE: Global Energy.

Entergy Market Calibration

To ensure consistency with the observed markets, Global Energy performed a calibration of the Strategic Planning Quasi-Rent/Scarcity-Rent bidding behavior algorithm. Figure 1-3 is a graphical representation of the 5x16 Entergy market price calibration efforts.

Figure 1-3
Entergy 5x16 Daily Market Prices; 1999-2003



SOURCE: Global Energy.

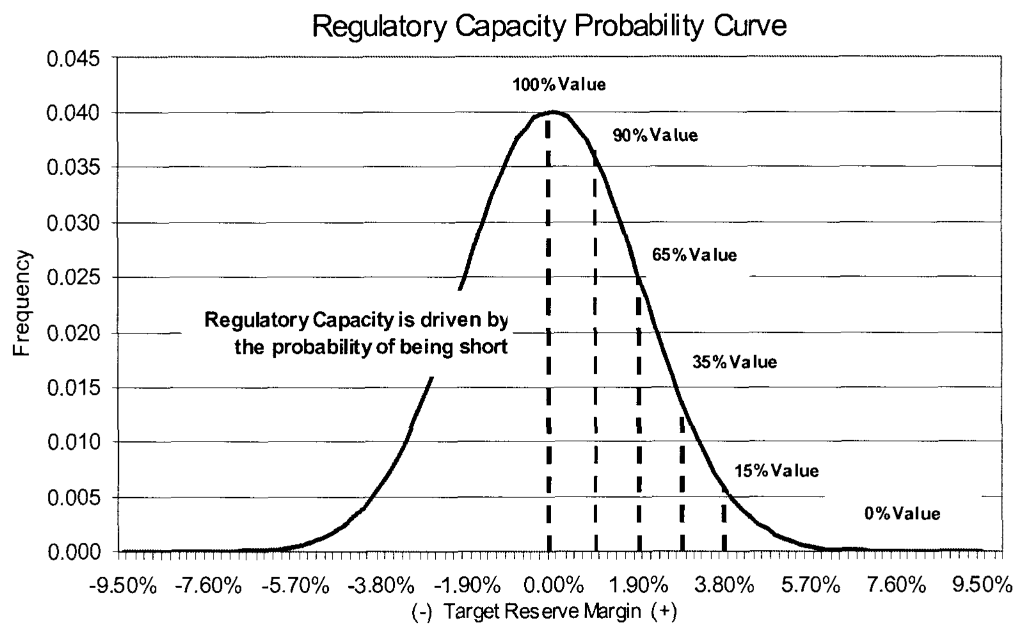
Generation Adequacy (ICAP/Regulatory Capacity)

To account for the capacity value for markets in the Northeast, Global Energy used the Installed Capacity (ICAP) markets to compensate the Competitive sector for their capacity. For non-RTO markets, Global Energy calculated the value of Regulatory Capacity (capacity with market-based energy).

Given Regulatory Capacity deals are bilateral and are not transparent, Global Energy devised a methodology to determine a proxy for Regulatory Capacity values. The methodology is based on the Load Serving Entity (LSE) buyer's perspective. Figure 1-4 illustrates the methodology an LSE uses to assess their reserve margin obligations. If the LSE forecasts a reserve margin obligation of 1,000 MW and they only have 950 MW of generation, then they would be willing to spend full market value (100 percent) for the 50 MW shortfall.

To account for the inherent uncertainty in the peak demand forecast, the LSE is willing to purchase additional capacity beyond the forecasted peak demand so long as the price is right (below full value). Figure 1-4 illustrates the diminishing value as a function of reserve margin. The diminishing Regulatory Capacity value fits a normal distribution that is correlated to the LSE's reserve margin uncertainty band.

Figure 1-4
Regulatory Capacity Probability Curve



SOURCE: Global Energy.

In the With Wholesale Competition case, competitive capacity owners receive Regulatory Capacity revenue driven by the distribution curve of Figure 1-4.

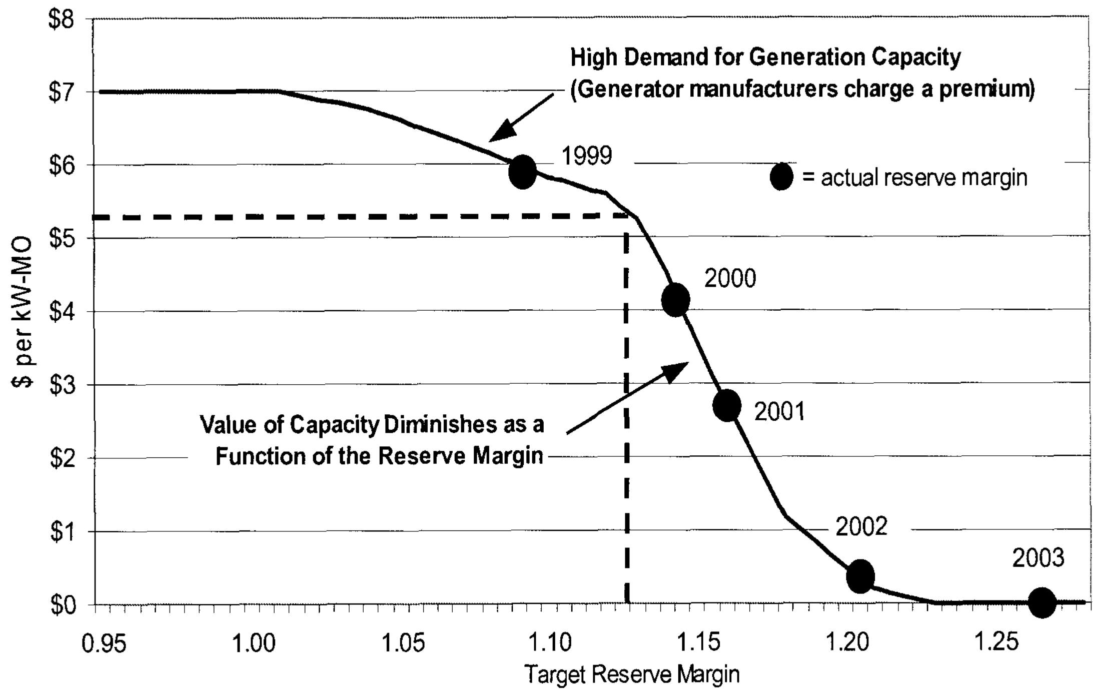
And, in times of very tight supply, the capacity owners receive Regulatory Capacity revenue above the 100 percent value if the reserve margin is well below the target. In 1999 and 2000, Regulatory Capacity prices were high due to a supply shortage. During this period of short supply, turbine manufacturers were able to increase the purchase price of a combustion turbine, plus buyers were willing to pay a reservation charge to obtain a place in queue for early delivery of a combustion turbine.

Eastern Interconnection Regulatory Capacity

The shape of the curve that Global Energy used to capture the plus/minus effect around a target reserve margin is illustrated in Figure 1-5. The capacity value, in $/kW-Month, is the levelized carrying charge of a combustion turbine plus recovery of the fixed O&M expense. The 100 percent recovery point is at the 13.6 percent target reserve margin. Sliding to the right of this point, an LSE pays less for Regulatory Capacity as the reserve margin increases. Sliding to the left, an LSE pays more for Regulatory Capacity as the supply/demand fundamentals drive the price higher.

The blue dots on the graph represent the actual reserve margin exhibited by the Eastern Interconnection market for the 1999-2003 study period. For this study, Global Energy calculated the value of Regulatory Capacity for each planning region. The target reserve margin varied by planning region in accordance with the requirements of the power pools. Figure 1-5 is a composite curve of all of the planning regions in the Eastern Interconnection.

Figure 1-5
Eastern Interconnection Composite Regulatory Capacity Value

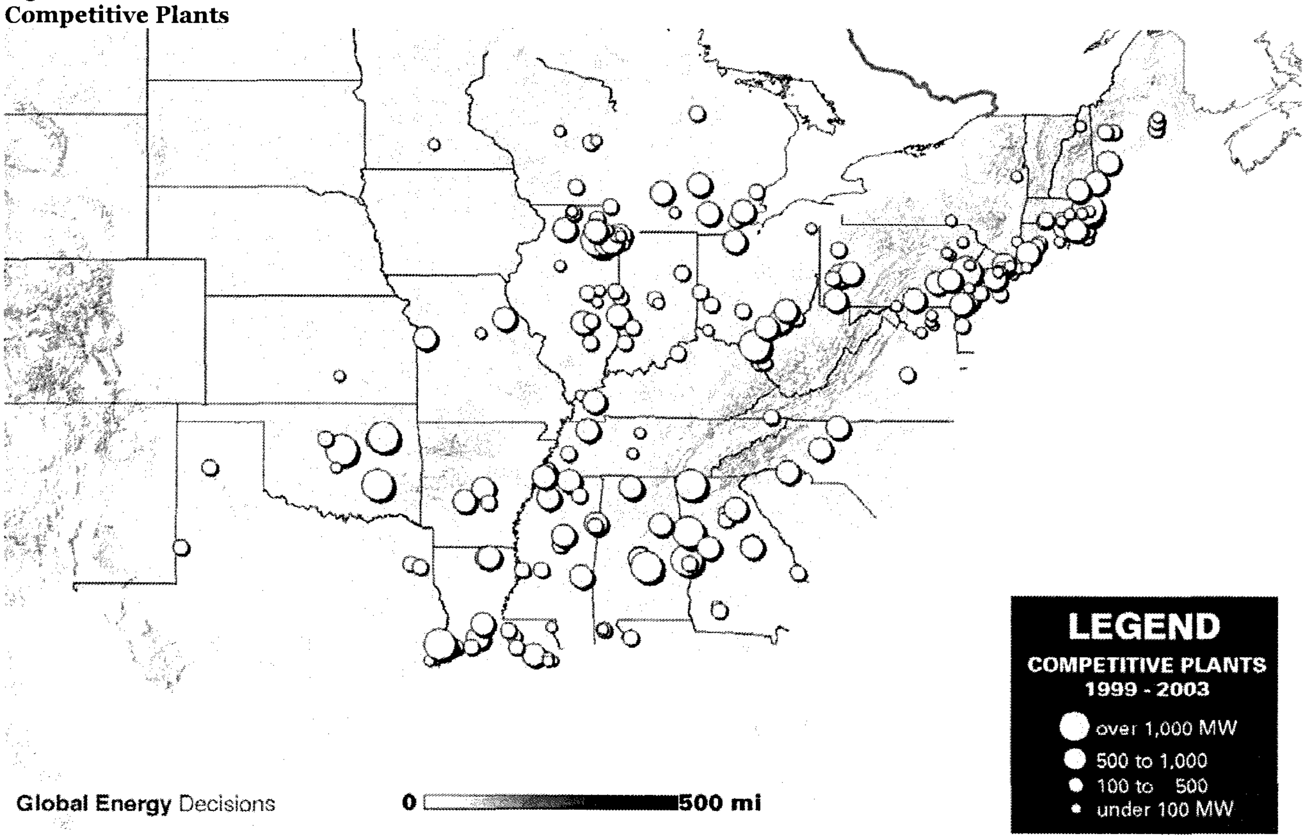


SOURCE: Global Energy.

Competitive Generation

During the 1999-2003 study period, 88,686 MW of competitive generation was added of which 56 percent was combined cycle and 44 percent was simple cycle. For this study, other fuel sources, such as waste coal and wind, were not included as part of the analysis. Figure 1-6 shows the dispersion of competitive plants added in the Eastern Interconnection during the study period.

Figure 1-6
Competitive Plants



Competitive Sector Capacity Value

To arrive at a Capacity Value for the Competitive sector, Global Energy used a methodology that compensated the owners for financial losses. The concept is that if the Competitive sector doesn't receive enough revenue from the energy market to cover its expenses plus a fair return on investment, then the LSEs would make up the difference.

The methodology is to calculate a profit and loss statement (P&L) for the Competitive sector to determine if it lost money. See Table 1-1.

If it did lose money, then the sliding slide of the Regulatory Capacity illustrated in Figure 1-5 was used to determine how much the LSE would be willing to pay for capacity. If the Regulatory Capacity value over-compensated the Competitive sector, a formula was used where the Capacity Value was equivalent to the minimum of either the financial loss or Regulatory Capacity value. Table 1-2 provides the calculation of the Capacity Value used in this study.

Table 1-1
Competitive Sector Profit and Loss Statement

Competitive Sector P&L	1999	2000	2001	2002	2003	1999-2003
Energy Revenue (millions $)	**$434**	**$1,166**	**$1,647**	**$3,279**	**$4,969**	**$11,495**
- Fuel	70	527	950	1,950	4,149	7,646
- Variable O&M	2	14	24	68	103	212
- Fixed Expenses	16	79	165	371	623	1253
- Levelized Carrying Charge	277	914	1,905	4,269	6,141	13,505
Profit/Losses	69	(368)	(1,397)	(3,378)	(6,047)	(11,121)

SOURCE: Global Energy.

Table 1-2
Capacity Value Calculation

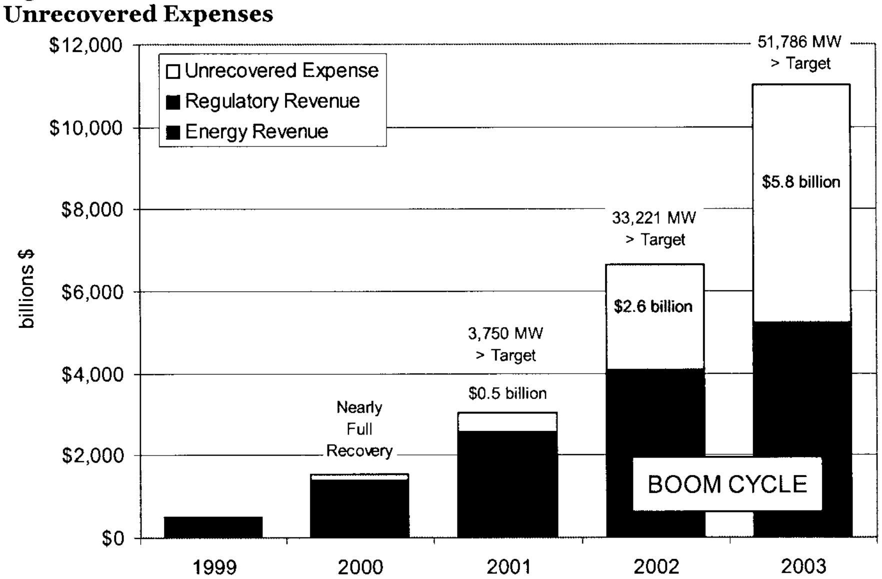
	1999	2000	2001	2002	2003	1999-2003
Losses (from Table 1-1)	0	(368)	(1,397)	(3,378)	(6,047)	N/A
Regulatory Capacity (millions $)	59	227	914	811	267	N/A
Capacity Value (millions $)	**$0**	**$227**	**$914**	**$811**	**$267**	**$2,220**

SOURCE: Global Energy.

Where Capacity Value = Minimum {Absolute Value (Losses), Regulatory Capacity}

Combining the energy revenue of $11.5 billion from Table 1-1 plus the capacity value of $2.2 billion from Table 1-2, the total revenue of the Competitive sector was determined to be $13.7 billion. This is the payment that the Regulated sector pays the Competitive sector in the With Wholesale Competition case. Figure 1-7 illustrates the Competitive sector's unrecovered expenses. As the graph illustrates, during boom cycles, the unrecovered expense is very large.

Figure 1-7
Unrecovered Expenses



SOURCE: Global Energy.

Competitive and Regulated Financial Exchange

From Tables 1-1 and 1-2, Global Energy estimates the Competitive sector sold $13.7 billion worth of energy and capacity to the Traditional sector. The values were $11.5 billion and $2.2 billion, respectively. Figure 1-8 illustrates the interaction between the Regulated sector and the Competitive sector for the With Wholesale Competition case.

Figure 1-8
With Wholesale Competition Case Financial Exchange

Regulated Sector

Operating Expenses

Fuel

+ Variable O&M

+ Energy Purchases

+ Capacity Purchases

Competitive Sector Revenues

SOURCE: Global Energy.

The five-year breakdown of the various Regulated sector expenses of the With Wholesale Competition case is shown in Table 1-3.

Table 1-3
With Wholesale Competition - Cost of Service

	1999	2000	2001	2002	2003	1999-2003
Fuel (Fossil and Nuclear)	28,905	31,651	31,600	31,188	33,627	156,971
+ Variable O&M	3,653	3,808	3,889	4,049	4,116	19,515
+ Competitive Energy Purchase	434	1,166	1,647	3,279	4,969	11,495
+ Competitive Capacity Value	0	227	914	811	267	2,220
+ Fixed O&M	-	-	-	-	-	-
+ Depreciation	-	-	-	-	-	-
+ Property Taxes	-	-	-	-	-	-
+ Income Taxes	-	-	-	-	-	-
+ Operating Income	-	-	-	-	-	-
Operating Expenses (millions $)	**32,992**	**36,851**	**38,050**	**39,328**	**42,980**	**190,200**

SOURCE: Global Energy.

Defining the Two Cases

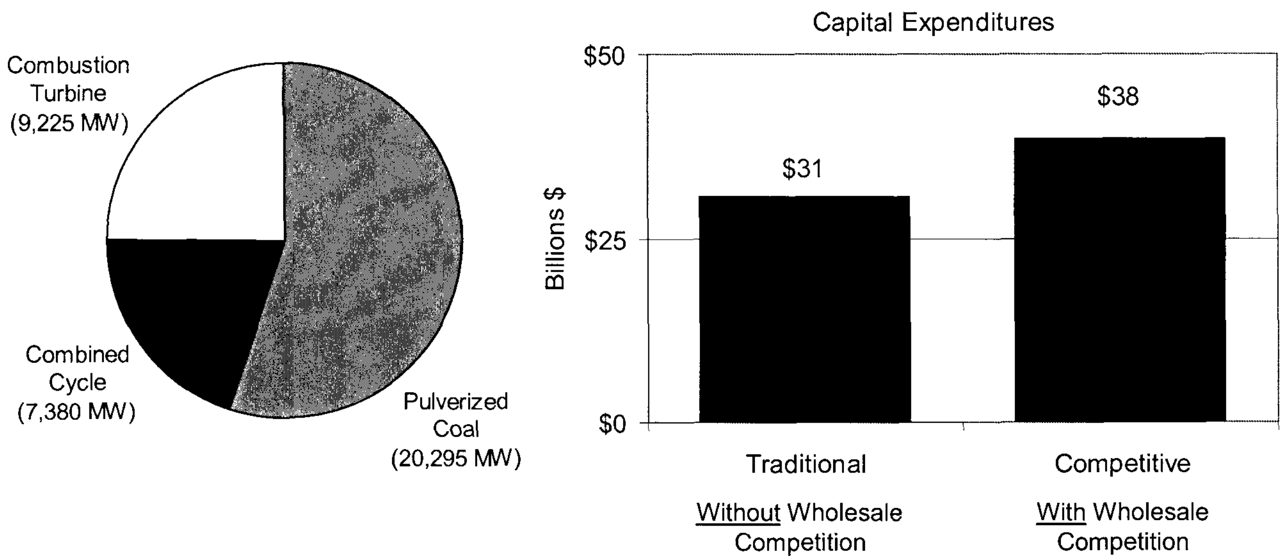
The With Wholesale Competition case differs from the Without Wholesale Competition case in three main areas.

1. Competitive Plants
   - In the Without Wholesale Competition case, it is assumed that no competitive or merchant plants would have been built; however, qualifying facilities built pursuant to PURPA requirements were included.
2. Regional Transmission Organization (RTO)
   - In the Without Wholesale Competition case, it is assumed that FERC Orders 888 and 2000 never occurred and that RTOs were not formed. RTO transmission rates are replaced with pancaked transmission rates, which traditionally existed in these areas.
3. Market-Based Rates for Wholesale Energy
   - In the Without Wholesale Competition case, it is assumed that marginal cost-based contracts replace market-based wholesale energy.

Traditional Power Plant Development (Without Wholesale Competition Case)

In the Without Wholesale Competition case, Global Energy calculated the level and mix of new generation that utilities would have built to satisfy minimum reserve margins and consumer energy requirements. That electric supply portfolio would have consisted of 55 percent pulverized coal, 20 percent combined cycle, and 25 percent combustion turbines. As shown in Figure 1-9, capital spent by the Regulated sector is $7 billion less than was spent by the Competitive sector.

Figure 1-9
Traditional Generation Supply Portfolio

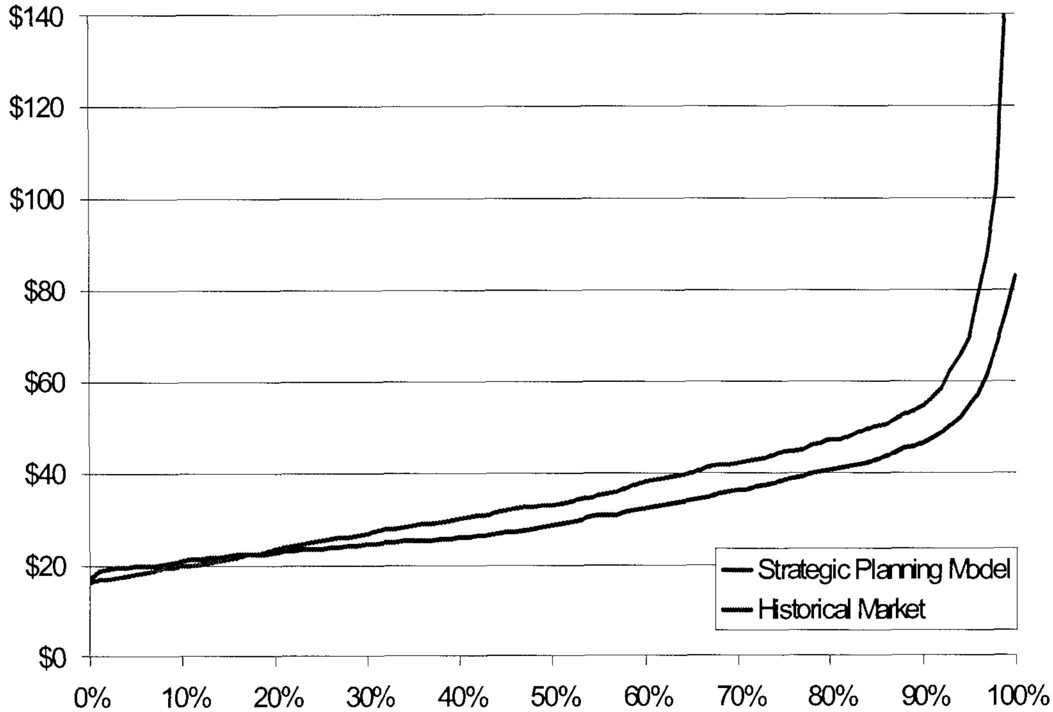


SOURCE: Global Energy.

Marginal Cost Based Energy Market

Figure 1-10 shows the market clearing price forecast derived from power exchanges at marginal cost based energy. This figure illustrates how the wholesale market behaves in Traditional Markets Without Wholesale Competition case.

Figure 1-10
Entergy 5x16 Marginal Cost Daily Market Prices; 1999-2003



SOURCE: Global Energy.

Return on Rate Base Calculation

Given the Regulated sector builds its own generation in the Without Wholesale Competition case, Global Energy calculated operating income for the incremental generation that was added using the return of rate base calculation and an allowed return on rate base of 8.5 percent.

Figure 1-11
Return on Rate Base

Revenues	
Base Revenues	205,342
Expenses	
Fuel	160,979
Competitive Energy Purchases	0
Competitive Capacity Value	0
Variable O&M	21,902
Fixed O&M	7,610
Depreciation	2,670
Property Taxes	931
Income Taxes	3,289
Operating Income	
Rate Base x Allowed Rate of Return	7,960

SOURCE: Global Energy.

The five-year breakdown of the various Regulated sector expenses of the Without Wholesale Competition case is shown in Table 1-4.

Table 1-4
Without Wholesale Competition - Cost of Service

	1999	2000	2001	2002	2003	1999-2003
Fuel (Fossil and Nuclear)	28,808	31,577	31,592	32,634	36,367	160,979
+ Variable O&M	3,919	4,194	4,399	4,633	4,757	21,902
+ Competitive Energy Purchase	-	-	-	-	-	-
+ Competitive Capacity Value	-	-	-	-	-	-
+ Fixed O&M	1,147	1,348	1,575	1,698	1,841	7,610
+ Depreciation	170	374	603	703	820	2,670
+ Property Taxes	35	112	201	269	314	931
+ Income Taxes	311	532	774	763	909	3,289
+ Operating Income	527	1,144	1,823	2,081	2,385	7,960
Operating Expenses (millions $)	**34,917**	**39,282**	**40,967**	**42,782**	**47,394**	**205,342**

SOURCE: Global Energy.

Comparing the Two Cases

The five-year consumer benefit of the With Wholesale Competition case versus the Without Wholesale Competition case was $15.1 billion. A comparative breakdown of the various expenses is shown in Table 1-5.

Table 1-5
Consumer Benefit - Cost of Service

	Without Wholesale Competition	With Wholesale Competition	Consumer Benefit
Fuel (Fossil and Nuclear)	160,979	156,971	4,008
+ Variable O&M	21,902	19,515	2,387
+ Competitive Energy Purchase	-	11,495	(11,495)
+ Competitive Capacity Value	-	2,220	(2,220)
+ Fixed O&M	7,610	-	7,610
+ Depreciation	2,670	-	2,670
+ Property Taxes	931	-	931
+ Income Taxes	3,289	-	3,289
+ Operating Income	7,960	-	7,960
Operating Expenses (millions $)	**205,341**	**190,201**	**15,140**

SOURCE: Global Energy.

The With Wholesale Competition case does not reflect expenses and returns associated with existing utility infrastructure. The Without Wholesale Competition case includes expenses and returns for new generation constructed by the Regulated sector. In essence, Global Energy is quantifying the cost and risk transfer of power plant construction between the two sectors (Competitive and Regulated). Table 1-6 provides a description of each variable of the operating statement.

Table 1-6
Operating Statement Variable Descriptions

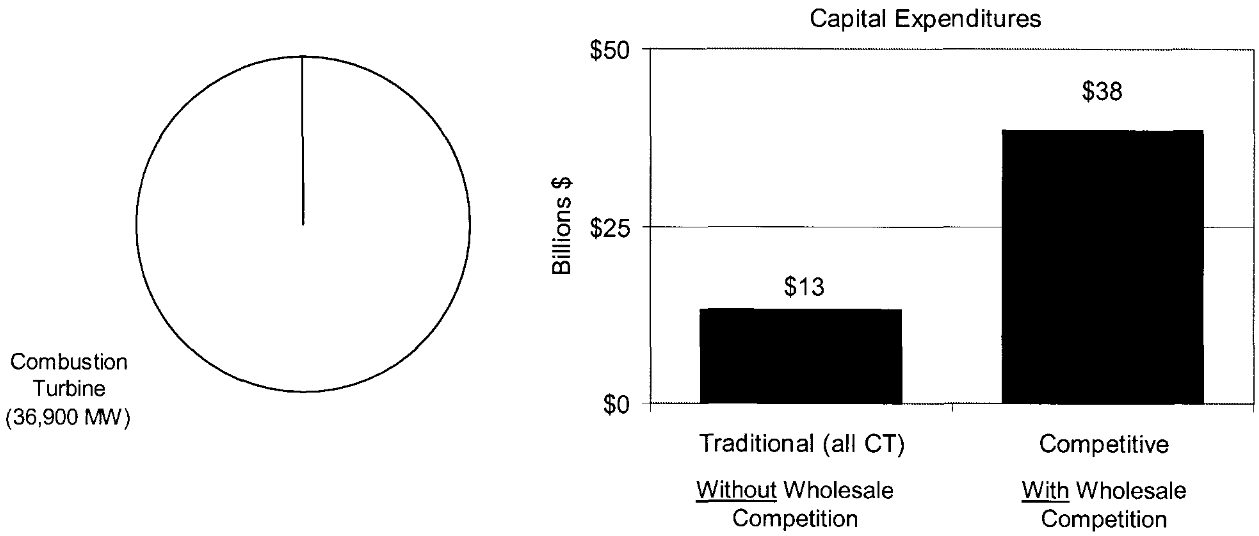
	Without Wholesale Competition	With Wholesale Competition
Fuel (Fossil and Nuclear)	Cost of fossil and nuclear fuel burned by existing utility infrastructure. This line item includes all plants (regardless of ownership) built prior to 1999, new rate base plants built in the 1999-2003 study period, and the 36,900 MW of traditional plants identified in Figure 1-9.	Cost of fossil and nuclear fuel burned by existing utility infrastructure. This line item includes all plants (regardless of ownership) built prior to 1999, plus new rate base plants built in the 1999-2003 study period. The 88,686 MW of competitive plants identified in Figure 1-6 are excluded from this line item.
Variable O&M	This line item includes all plants (regardless of ownership) built prior to 1999, new rate base plants built in the 1999-2003 study period, and the 36,900 MW of traditional plants identified in Figure 1-9.	This line item includes all plants (regardless of ownership) built prior to 1999, plus new rate base plants built in the 1999-2003 study period. The 88,686 MW of competitive plants identified in Figure 1-6 are excluded from this line item.
Competitive Energy Purchase	Not applicable. In this case there are no competitive plants.	Cost of energy purchased from the competitive plants identified in Figure 1-6.
Competitive Capacity Value		Cost of capacity purchased from the competitive plants identified in Figure 1-6.
Fixed O&M Depreciation Property Taxes Income Taxes	These expenses are associated with the 36,900 MW of traditional plants constructed in the study period.	Expenses were not included for existing utility infrastructure because it would be the same for with and without cases.
Operating Income	This line item is the operating income of the 36,900 MW of traditional plants constructed in the study period. The operating income is calculated as rate base times a return on rate base of 8.5 percent.	Operating income was not included for existing utility infrastructure because it would be the same for with and without cases.

SOURCE: Global Energy.

Low Capital Cost Sensitivity

One of the largest drivers of the $15.1 billion consumer benefit was the mix of new resources Global Energy assumed would be built. To stress test this assumption, Global Energy developed a low capital cost case in which only simple cycle combustion turbines were built.

Figure 1-12
Traditional Generation Supply Portfolio – Low Capital Cost Scenario



SOURCE: Global Energy.

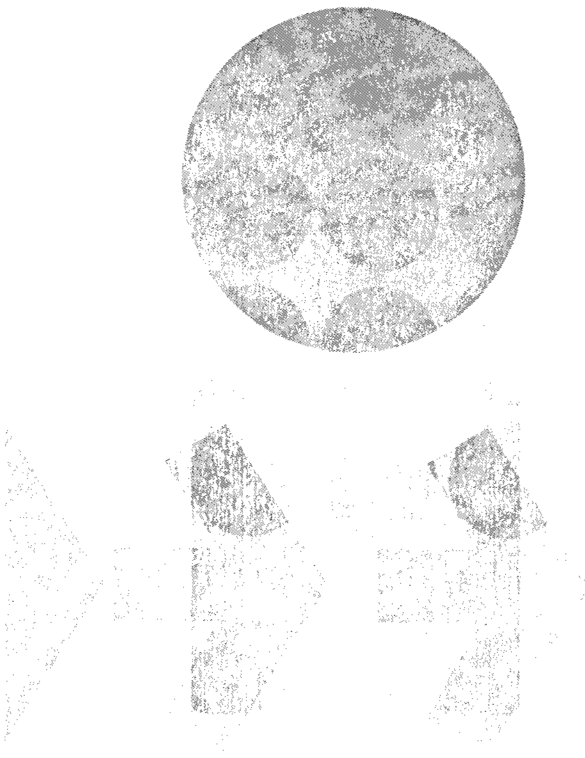
Consumer Benefit of the Low Capital Cost Case

The five-year consumer benefit of the With Wholesale Competition case versus the Low Capital Cost case Without Wholesale Competition was $9.4 billion. A comparative breakdown of the various expenses is shown in Table 1-7. This case can be thought of as the least amount of consumer benefit or a "floor."

Table 1-7
Low Capital Cost Consumer Benefit - Cost of Service

	Without Wholesale Competition	With Wholesale Competition	Consumer Benefit
Fuel (Fossil and Nuclear)	165,998	156,971	9,027
+ Variable O&M	21,144	19,515	1,630
+ Competitive Energy Purchase	-	11,495	(11,495)
+ Competitive Capacity Value	-	2,220	(2,220)
+ Fixed O&M	5,981	-	5,981
+ Depreciation	1,152	-	1,152
+ Property Taxes	401	-	401
+ Income Taxes	1,448	-	1,448
+ Operating Income	3,435	-	3,435
Operating Expenses (millions $)	199,559	190,200	**9,359**

SOURCE: Global Energy.



Section Two

Wholesale Competition Dramatically Improved the Efficiency of Power Plants

2
Wholesale Competition Dramatically Improved the Efficiency of Power Plants

Global Energy conducted an analysis and review of the North American generation fleet operations to assess improvements and efficiencies attributable to competitive forces. This analysis was based on a study period of 1999-2004. 1999 was selected as a starting period because it was representative of the maturation of restructuring in many parts of the country. Two factors influenced this as a starting point:

- With the passage of EPAct, Congress opened the door to wholesale competition in the electric utility industry by authorizing FERC to establish regulations to provide open access to the nation's transmission system. FERC's subsequent rules, issued in April 1996 as Order 888, facilitiated increased wholesale competition.
- In an effort to continue the evolution of competitive wholesale power markets, FERC Order 2000, released in December 1999, requested the formation of regional transmission organizations further facilitating competition.

Global Energy uncovered strong evidence indicating the electric utility industry has improved its operations and efficiencies largely because of competitive forces. Some of the power plants with great gains in efficiency had been auctioned off by their prior owners as relatively poor performers. But the skill of experienced fleet operators; the standardization of procedures and maintenance; and the combined buying power of fuel, equipment, and supplies have produced dramatic improvements in capacity factors and plant performance. The cost savings and energy efficiency resulting from reduced refueling outages, improved load factors and reliability continues to substantially benefit consumers.

The analysis focused on the nuclear and coal-fueled generating units for traditional and competitive operators. Traditional operators are best defined as investor-owned utilities, municipalities, and cooperatives that are subject to retail rate regulation. Competitive operators are best defined as independent power producers and other generators that are not subject to rate regulation.

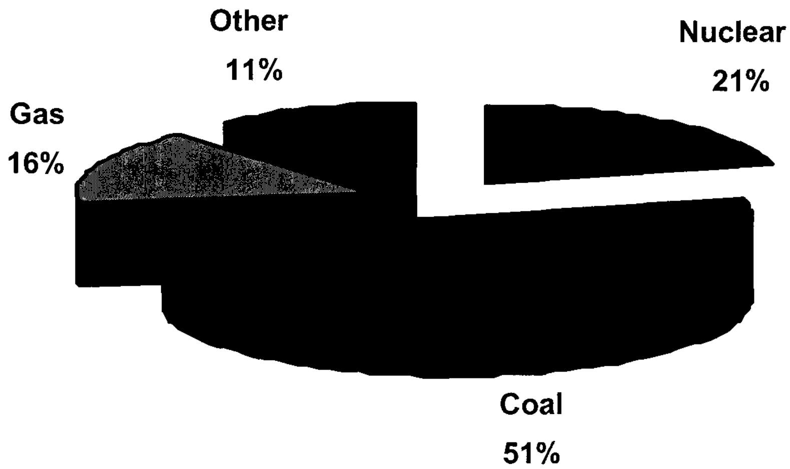
Global Energy Intelligence's **Energy Velocity™** database was the main data source utilized. Energy Velocity provides a comprehensive view of the power market. It combines all the data on the electric industry with complete coverage on IOUs, municipal utilities, generation and transmission cooperatives, distribution cooperatives, non-regulated market participants, and generating assets. Energy Velocity collects information from Global Energy primary research, websites, state and federal agencies, EIA and NERC ES&D. Unit level information is available for existing and planned plants in the United States, Canada, and Mexico.

All cost information reported in this section has been adjusted for inflation using the chained consumer price index for energy.

Nuclear Generation

Nuclear generation makes up 10 percent of the U.S. installed power generation capacity by fuel and about 20 percent of actual net generation each year.[1] Figure 2-1 shows the generation mix for the industry at the end of 2004.

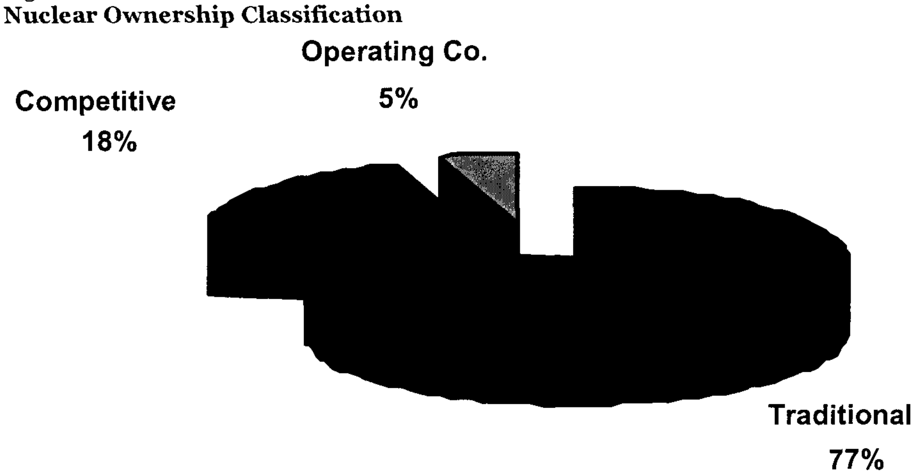
Figure 2-1
2004 Generation Mix



SOURCE: Global Energy.

Nuclear operations are a significant influence on the cost of electricity for the consuming public. Electric utility restructuring led to the consolidation of nuclear operations through the purchase and sale of nuclear facilities across the country by experienced nuclear fleet operators such as Exelon and Entergy. These sales most likely would not have occurred had this flexibility not existed. Global Energy's analysis focused on a view of the nuclear generation based on the classifications in Figure 2-2 where traditional represents plants owned and operated by IOUs and competitive plants that were sold and purchased. For purposes of the study we did not evaluate plants operated by an outside source.

Figure 2-2
Nuclear Ownership Classification



SOURCE: Global Energy.

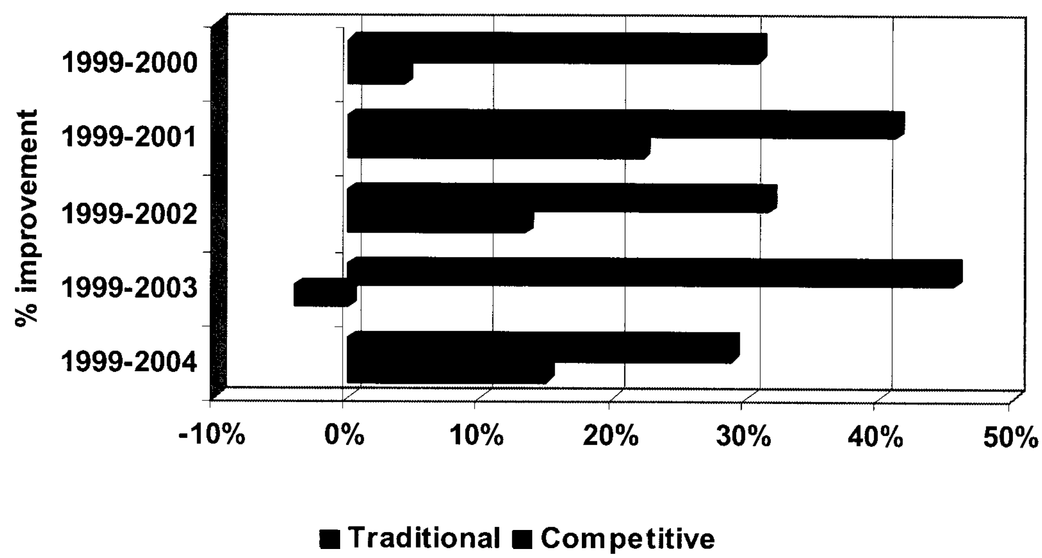
[1] Global Energy Reference Case.

A number of nuclear facilities in the competitive category were considered "troubled" and in danger of being shut down and decommissioned. Under competitive market conditions, many of these nuclear power plants have been sold or their operation was contracted out to experienced nuclear fleet operators on a merchant basis. Consumers have benefited from the continued operation of these units in addition to the improvements in operation and efficiencies.

Nuclear Refueling Outage Time Reduced

Global Energy conducted an analyses and review of the Nuclear Regulatory Commision (NRC) daily unit outage information. In this review of information Global Energy ascertained whether the outage was related to a refueling and aggregated the length of the outages for the study period by year. Competitive units experienced a 26 percent reduction in the length of refueling outages since 1999. They have also displayed significant and continual improvement over the study period as displayed in Figure 2-3. Figure 2-3 depicts the percentage improvement.

Figure 2-3
Percent Reduction in Length of Refueling Outages since 1999



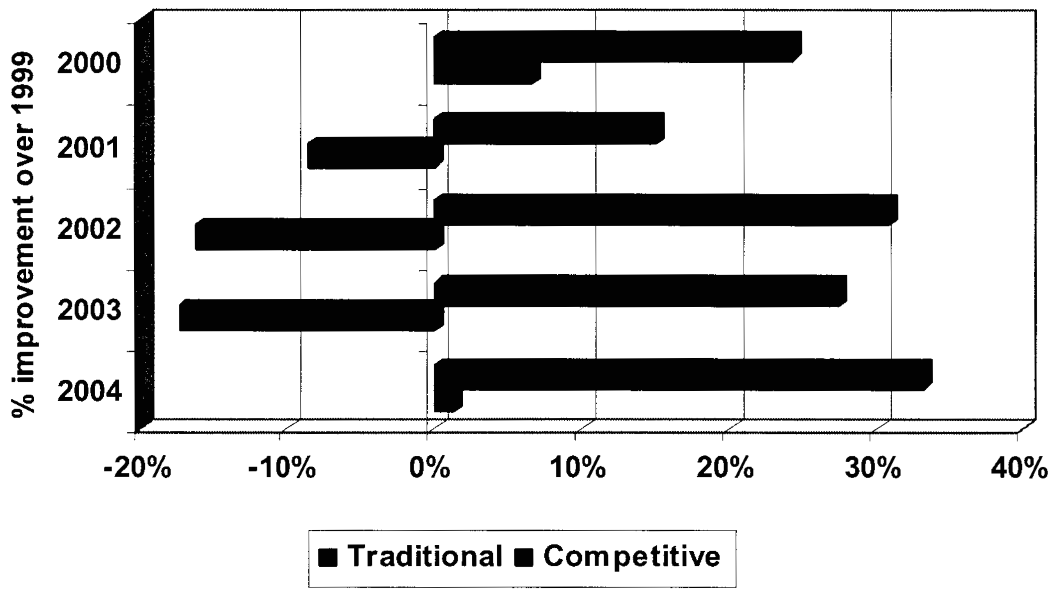
SOURCE: Global Energy.

Traditional nuclear units experienced a 4 percent decline in 2003 over 1999 representing a total of 75 days. This was mainly due to extended outages at approximately 10 facilities. Overall the industry experienced a decline in total refueling outage days of nearly a year. Competition and industry restructuring of the industry have positively influenced the management of nuclear facilities through competitive pricing.

Nuclear Operations and Maintenance Expenses Lowered

Global Energy conducted an analysis of the nuclear facilities total fixed and variable operations and maintenance expense. These costs were reviewed in total. Classification of fixed and variable is somewhat subjective and not consistently reported in the industry. Competitive units experienced a 33 percent reduction in O&M expense on a $/MWh over 1999. Figure 2-4 is a comparison of expense increases/reductions experienced since 1999 for both traditional and competitive nuclear operations adjusted for inflation. Competitive facilities have consistently reduced expenses over the study period.

Figure 2-4
Nuclear O&M Reductions since 1999



SOURCE: Global Energy.

Note that in 1999 competitive nuclear facilities were experiencing a cost of almost $15/MWh whereas traditional facilities cost were slightly more than $10/MWh. This disparity is largely due to the fact that the competitive fleet of nuclear plants had a higher cost structure prior to their transfer to, or acquisition by, the Competitive sector. However, by 2004, the skill of experienced fleet operators; the standardization of procedures and maintenance; and the combined buying power for fuel, equipment, and supplies dramatically improved plant costs and performance. Now the "poor" performers are indistinguishable from traditional facilities, as both have operating and maintenance costs of approximately $10/MWh.

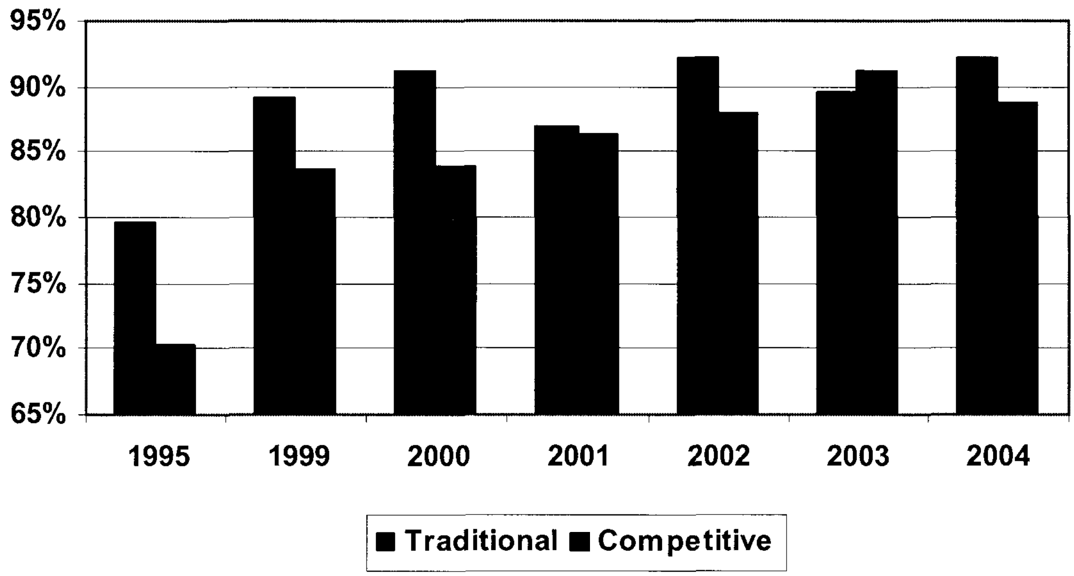
Nuclear Plant Capacity Factors Increased

Nuclear units have relatively low variable costs and thus are low dispatch-cost generating facilities. As such, a measurable benefit is a high capacity factor. It is beneficial for the consumer and operator for these units to operate as much as possible since nuclear generation is considered one of the least expensive forms of generation. One measure of the operation is capacity factor, which is best defined as the percentage of time that a unit is operable. Since nuclear units are "must run" one would expect the percentage of operation to be near 100 percent. However, forced outages, refueling, and maintenance must be performed. Reductions in refueling and maintenance are factors within the operator's control that may be improved. As stated earlier in the report, both refueling and maintenance have improved. Prior to competitive forces shifting the management and operation of nuclear facilities to more experienced operators focused on improving plant performance in a competitive market environment, nuclear facilities were often operating at "sub-optimal" levels in 1995. Since 1995, the nuclear units have displayed continual improvement. According to the Nuclear Energy Institute (NEI), nuclear plants had record output and stable costs in 2004. U. S. plants generated a record 786.5 million MWh in 2004, breaking the 2002 record of 780 million MWh. NEI's figures put the 2004 average net capacity factor at 90.6 percent, trailing only the 91.9 percent achieved in 2002 and 90.7 percent in 2001.

The nuclear industry experienced a 17 percent increase in capacity factors since 1995. Global Energy also found that since 1995 the increase in capacity factor resulted in enough energy to power more than 10 million residential households for one year.[2]

Figure 2-5 depicts capacity factors for the study period for both traditional and competitive facilities.

Figure 2-5
Nuclear Capacity Factors; 1995-2004



SOURCE: Global Energy.

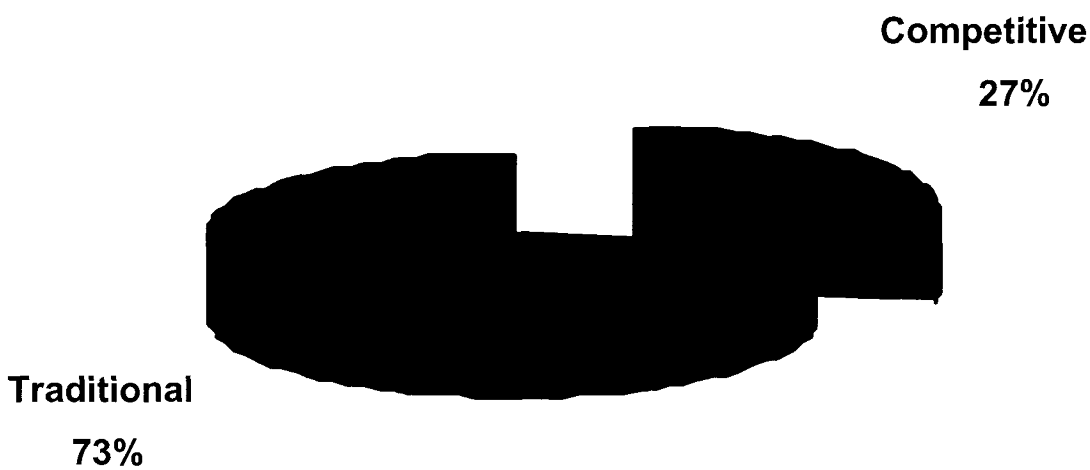
[2] Based on average residential customer annual usage of 10,803 kWh per year.

Coal Generation

Coal-fueled generation is the most predominant type of generating resource in the United States. Even with the additional natural gas-fueled generation, coal still represented 51 percent of total net generation in 2004 as shown in Figure 2-1. Coal-fueled facilities have also benefited from restructuring. As the industry moves away from vertically integrated utilities to non-regulated independent power producers competitive pressures have forced regulated entities to improve operations.

To identify how competitive pressures affected coal generation, Global Energy conducted an analysis of coal-fueled generation based on a classification of traditional and competitive utility structures. Traditional utility structures represent generating facilities owned by investor-owned utilities, municipalities, and cooperatives that are subject to retail rate regulation. Competitive industry structures represent generating facilities owned by independent power producers that are not subject to retail rate regulation. Figure 2-6 shows the percentage of generation from each classification.

Figure 2-6
Coal Plant Generation

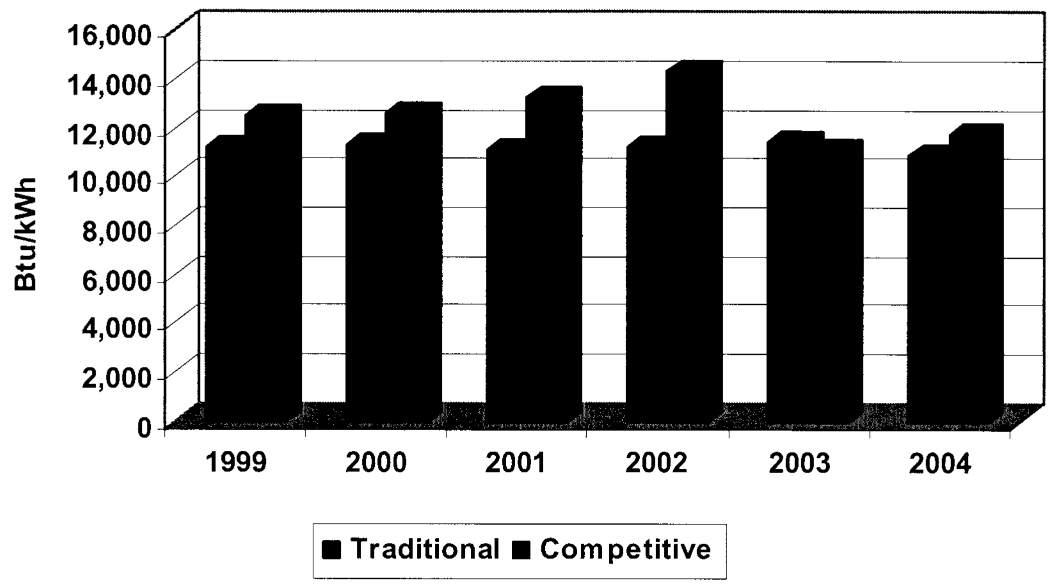


SOURCE: Global Energy.

Coal Heat Rates Improved

Heat rate is a measurement of a generating station's thermal efficiency and is usually expressed in Btu/kWh; the lower the Btu/kWh the higher the efficiency of the unit. Global Energy analyzed coal-fueled units across the United States and evaluated the efficiencies for traditional and competitive units. The traditional units consist of a more modern fleet, while the competitive units are older, less-efficient performers before they were transferred or sold by the prior owners. Nevertheless, the new competitive owners were able to achieve a 6 percent heat rate improvement. The environmental impact of the heat rate improvement is 12.3 million fewer tons of coal burned each year for the competitive fleet. Figure 2-7 shows that competitive units improved heat rates by 6 percent while traditional improved 3 percent since 1999. Overall, industry-wide heat rates for coal plants improved 4 percent during the study period.

Figure 2-7
Coal Heat Rate Improvements



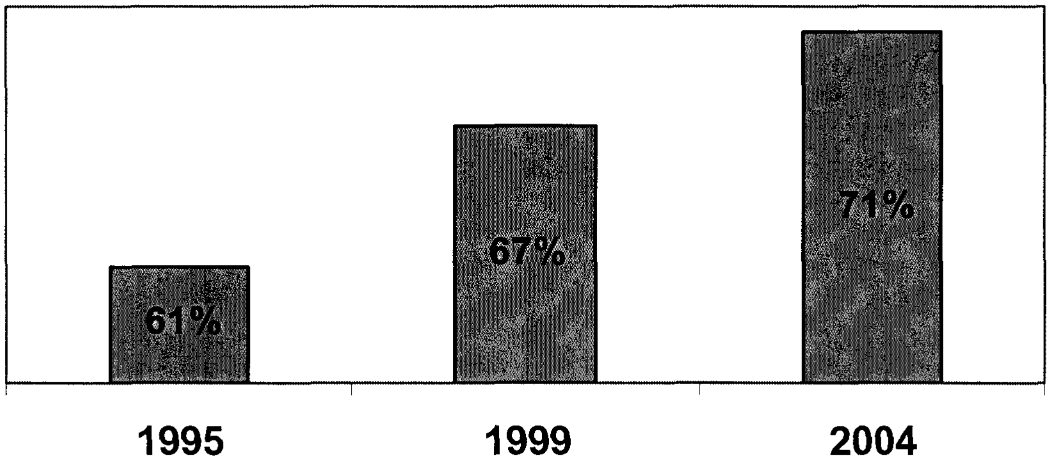
SOURCE: Global Energy.

The reduction in competitive units is attributable to efficiencies being realized in the operation of the units and not retirements. The competitive fleet retired approximately 1,000 MW since 1999 with the average unit size being about 30 MW and an average heat rate of 12,185 Btu/kWh. The traditional fleet retired over 2,500 MW with an average size unit of 55 MW, nearly double the size of units retired by the competitive fleet.

Coal Plant Capacity Factors Increased

As with nuclear plants, the fleet of coal plants saw an improvement in capacity factors in the decade between 1995 and 2004. Figure 2-8 demonstrates that coal-fueled power plant capacity factors increased overall by 16 percent from 61 percent to 71 percent. Because there are three times as many MW of coal-fueled capacity as there are MW of nuclear plant capacity, this increase had the effect of making at least another 50,000 MW of effective generating capacity available for dispatch in 2004 as there was prior to 1995. Furthermore, the increase in capacity factors for coal-based plants was enough electricity to power 25 million residential households for a year.

Figure 2-8
Coal Plant Capacity Factors; 1995-2004



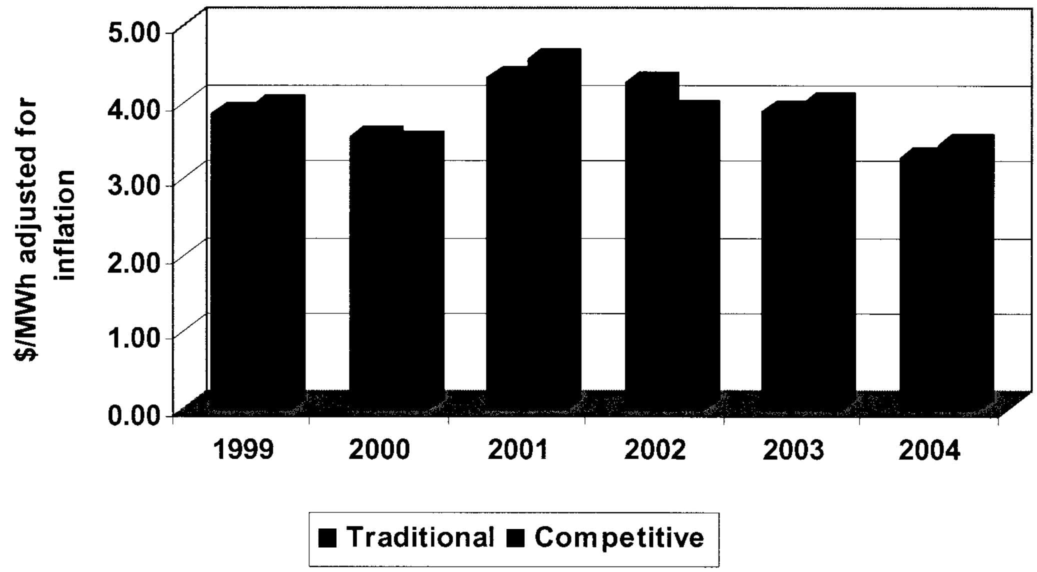
SOURCE: Global Energy.

The competitive generation fleet consists of older and smaller units which results in higher overall heat rate levels. Competitive coal fleet's median size is 474 MW compared to 669 MW for traditional units. Competitive pressures have compelled traditional utilities to maintain costs while improving their overall efficiency. Consumers benefit from the overall improvement in efficiencies of coal generation regardless of whether they are related to traditional or competitive facilities. During the study period, utilities have either switched fuels or installed clean air equipment to comply with SO_2 regulations. All of these actions generally increase heat rates and yet improvements were recognizable overall.

Coal Operations and Maintenance Expenses Declined

Global Energy conducted an analysis of the coal fleet's operation and maintenance expense to ascertain any influences of competition on these costs. Overall coal O&M expense has declined when adjusted for inflation. Figure 2-9 shows that fixed and variable O&M expense based on a $/MWh has declined by 14 percent since 1999 for the industry. Competitive facilities improved 13 percent while traditional experienced a 15 percent improvement.

Figure 2-9
Coal O&M Improvements



SOURCE: Global Energy.

Reductions in the operating costs of base load, lower-cost plants, such as coal, benefit consumers through lower purchased power costs and regulated entities' ability to manage costs such that increases in rates are not necessary.

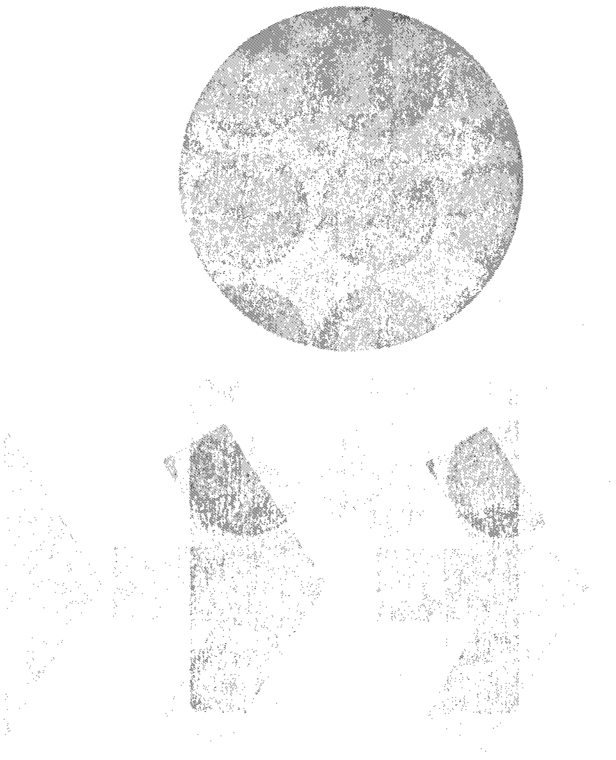
Overall Observations

The empirical evidence indicates that the electric utility industry has improved its operations and efficiencies. Competitive utility structures are at the forefront of these improvements either directly or indirectly, as demonstrated by the dramatic change in operating performance.

Overall nuclear operations and improvements best display the "direct" effects of competitive structures. As mentioned previously in the report, most of the units considered as competitive were previously in danger of being decommissioned and shut down. These albatrosses around the neck of a utility operator became star performers for the Regulated and Competitive plant operators skilled in running a fleet of nuclear plants. These units have a direct impact on the consumer through their continued and much improved operations.

The overall coal generation fleet has displayed improvements in cost and efficiency. The lines of contribution between traditional and competitive are not as clear cut as nuclear operations. One must think in the realm of previous traditional operations in that the mind set was to "throw money" at the operation of these units and pass it through to consumers. With the advent of competition, the players in the industry were no longer incented to continue with this mind set and thus the turnaround in the efficiency and operations of the coal generation fleet. The competitive structure has clearly imposed pressures resulting in these improvements.

Refer to Appendix C for supporting information.



Section Three

Impact of Regional Transmission Organizations (RTO)

3
Impact of Regional Transmission Organizations (RTOs)

Introduction

To test the impact of competition in expanded wholesale power markets, Global Energy assessed the impacts of integrating Commonwealth Edison (ComEd), American Electric Power (AEP), and Dayton Power & Light (DPL) into the PJM regional power market. The results of the analysis were that the benefits of expanding the PJM wholesale power market in 2004 produced $85.4 million in annualized production cost savings to wholesale customers in the Eastern Interconnection.

These savings were achieved through reduced transmission barriers, or seams, and the entry of new competitors to the market. FERC decisions had enabled additional market participants such as Exelon's ComEd, AEP, and DPL to join the PJM market. The results of competitive forces at work was immediate sending price signals throughout the broader regional power markets where power buyers searching for the lowest-cost supply available found them from a now wider universe of generators, marketers, and suppliers.

PJM Case Study

While wholesale power markets have been functioning in the United States several decades, they continue to evolve. This evolution has been driven primarily by FERC's Standard Market Design process and FERC's goal to see Regional Transmission Organizations (RTO's) formed throughout the United States. The objective of this Case Study was to identify a recent example of markets integrating into a single RTO and determine whether or not the market integration provided consumer benefits.

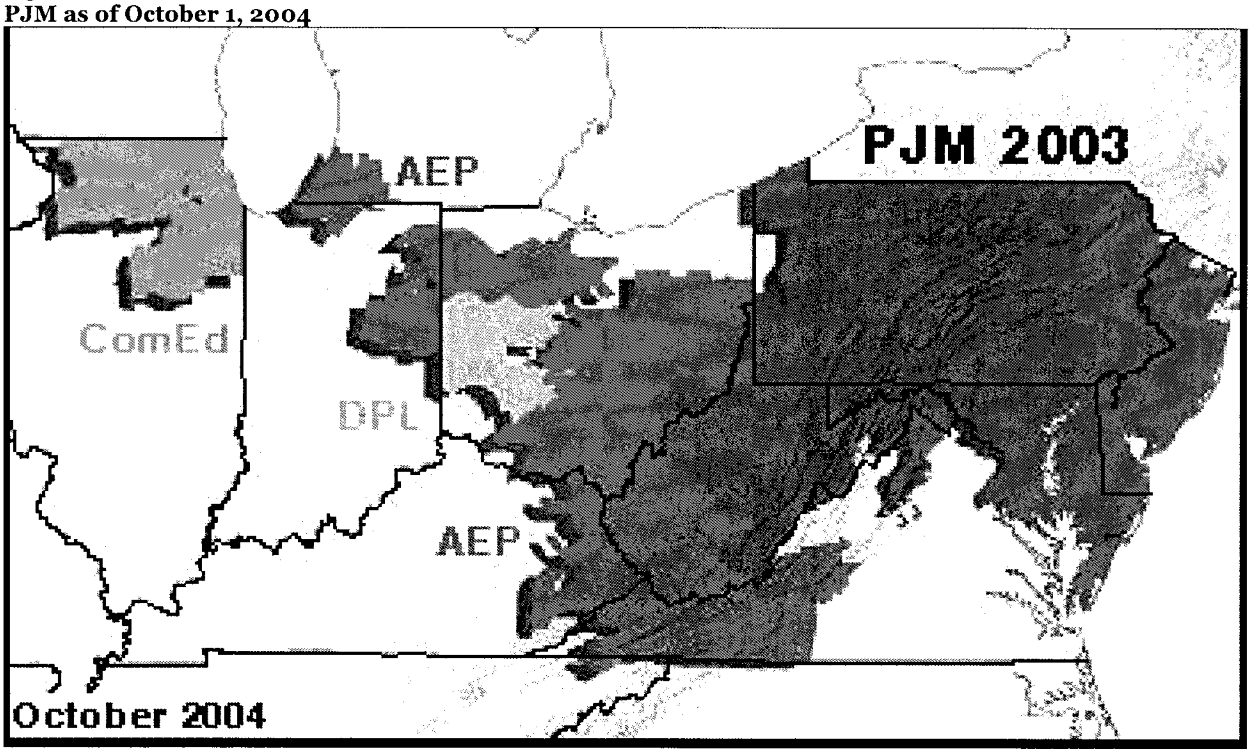
The PJM Interconnect in 2004 proved an excellent subject for this Case Study. Global Energy chose the PJM Interconnect in 2004 for several reasons. First, ComEd, AEP, and DPL joined PJM in 2004, making PJM the largest centrally dispatched, competitive wholesale electricity market in the world. Second, according to an internal analysis performed by PJM, changes in supply and demand fundamentals from 2003 to 2004 translated into lower power prices for PJM.

Global Energy's independent analysis studies the integration of ComEd, AEP, DPL and PJM's energy markets. The results confirmed PJM's conclusions that, in 2004, changes in supply and demand fundamentals resulted in lower PJM prices in 2003 than 2004, and quantified the annualized production cost benefits to PJM customers and the entire Eastern Interconnect at$69.8 million and $85.4 million, respectively.

PJM's Internal Analyisis

The integration of ComEd, AEP and DPL resulted in significant growth in the PJM market. In 2003, PJM comprised of 76,000 MW of installed generating capacity and a peak load of 63,000 MW. By October of 2004, PJM comprised of 144,000 MW of installed capacity and approximately 107,800 MW of peak load.

Figure 3-1
PJM as of October 1, 2004



SOURCE: Global Energy.

According to an internal analysis performed by PJM of the locational marginal prices (LMPs) in its energy spot markets, the impact of supply and demand fundamentals on market behavior from 2003 to 2004 translated into lower power prices for PJM. While average PJM power prices actually increased by 7.5 percent from 2003 to 2004, PJM showed that the increase was primarily a result of higher fuel prices.[1] PJM performed a fuel adjustment of PJM prices and determined that fuel-adjusted PJM power prices actually declined by 4.2 percent from 2003 to 2004.

Table 3-1
PJM Load-weighted LMP ($ per MWh); 2003-2004

	2003	2004	Change
Average LMP	$41.23	$44.34	7.5%
Fuel Adjusted LMP	$41.23	$39.49	-4.2%

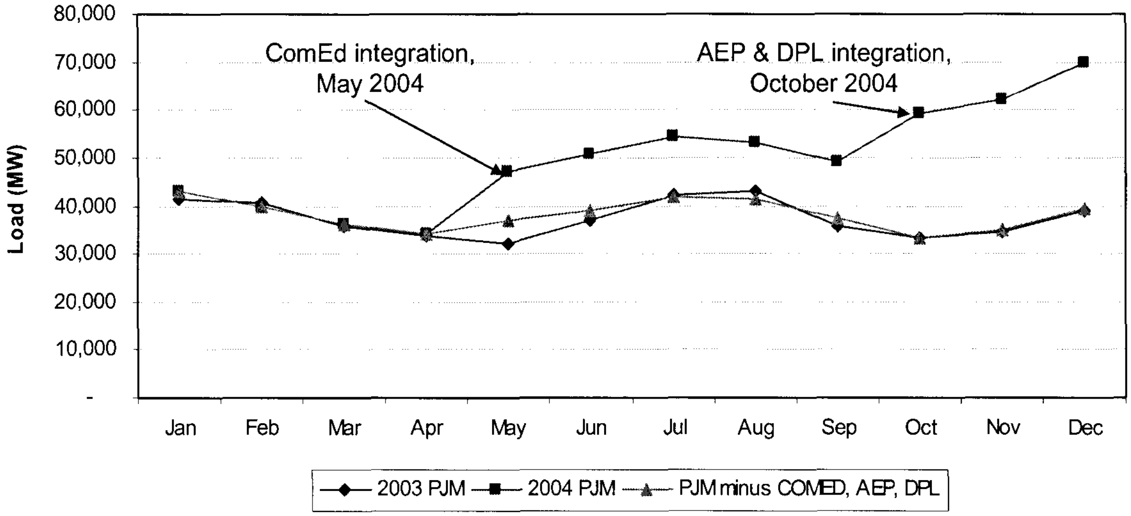
SOURCE: PJM.

[1] The PJM power prices referenced here are load-weighted average power prices. The simple, hourly average PJM LMP was 10.8 percent higher in 2004 than in 2003, according to PJM.

PJM's Assessment of the Supply & Demand

PJM attributed the lower fuel-adjusted power prices to an energy market relatively long on supply, combined with moderate demand, a condition driven primarily by the integration of ComEd into PJM. AEP and DPL joined PJM after the critical peak summer months and their impact on supply and demand was less significant in 2004. On the supply side, during the June-to-September 2004 period, PJM energy markets received a maximum of 109,600 MW in supply offers (net of real-time imports or exports). The 2004 net supply offers represented an increase of approximately 29,800 MW compared to the comparable 2003 summer period. On the demand side, the PJM system peak load in 2004 was 77,887 MW, a coincident summer peak load reflecting the Mid-Atlantic region, the APS control zone, and the ComEd control area. The PJM peak load in 2003 of 61,499 MW occurred prior to the integration of the ComEd control area.

Figure 3-2
PJM Average Monthly Loads; 2003-2004



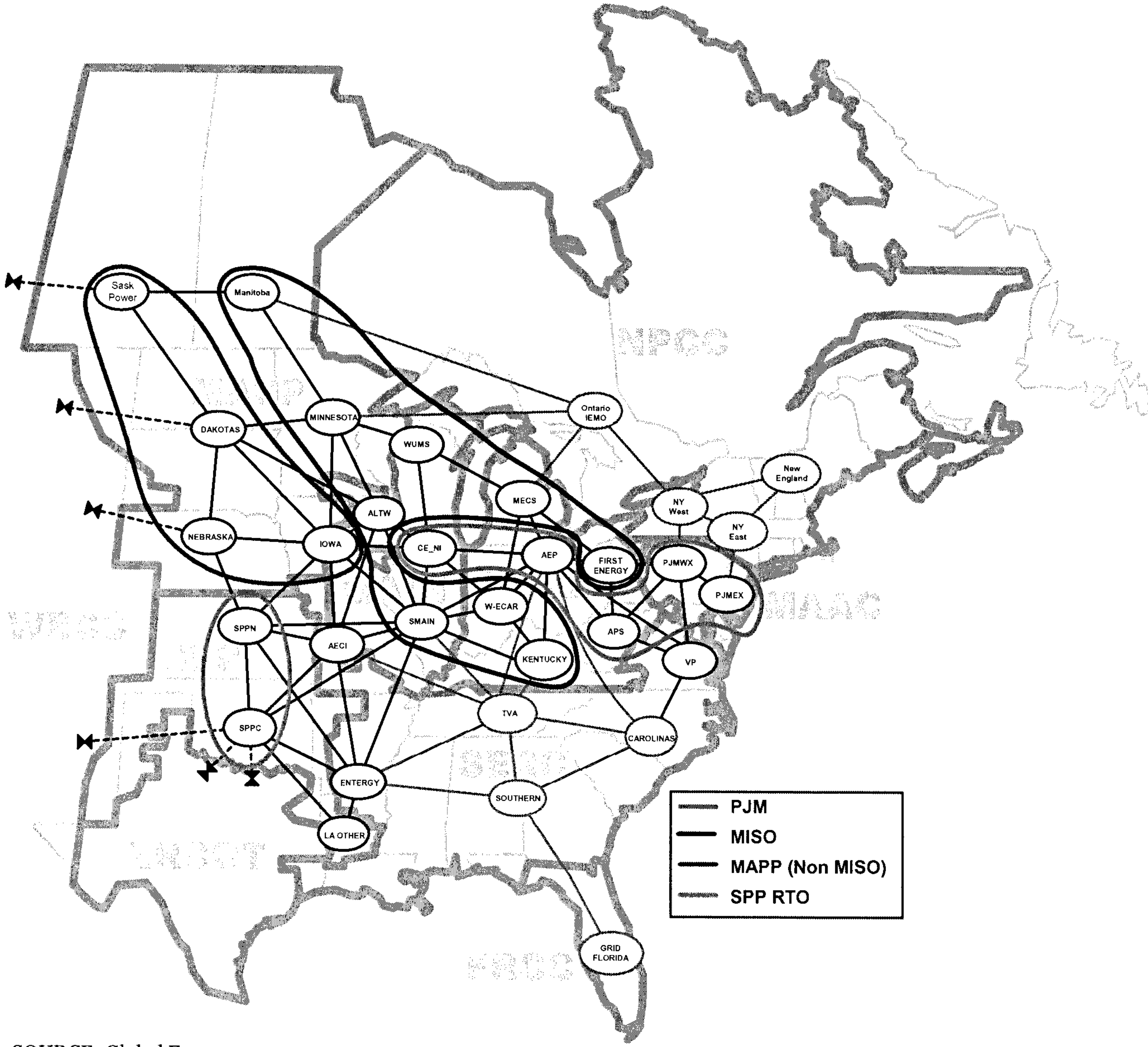
SOURCE: Global Energy.

Global Energy's PJM Case Study Approach

For this case study, Global Energy performed a fundamental Eastern Interconnection market simulation to test PJM's conclusions, account for all price determinants not directly related to the integration, and to quantify the impacts associated with the integration of ComEd, AEP, and DPL supply and demand with that of PJM. Global Energy's approach was to analyze and quantify the impact of reducing the seams, in the form of pancaked wheeling charges, between the ComEd, AEP, DPL and PJM energy markets. By isolating pancaked wheeling charges in its analysis, Global Energy captured the primary structural change to ComEd, AEP, DPL and PJM's energy market supply and demand.

Global Energy employed a production cost savings model using its **EnerPrise™ Market Analytics** *powered by PROSYM®* module, which measures production costs, such as fuel and operations and maintenance costs. The study compared the production costs of a "Competition Case" which simulated PJM as it was in 2004 and compared these costs to a "Without Competition Case" in which the 2004 market as if ComEd, AEP, and DPL never joined PJM. The study included the entire Eastern Interconnect. Because Dominion Resources in Virginia did not joint PJM until January 1, 2005, it is not included in this analysis.

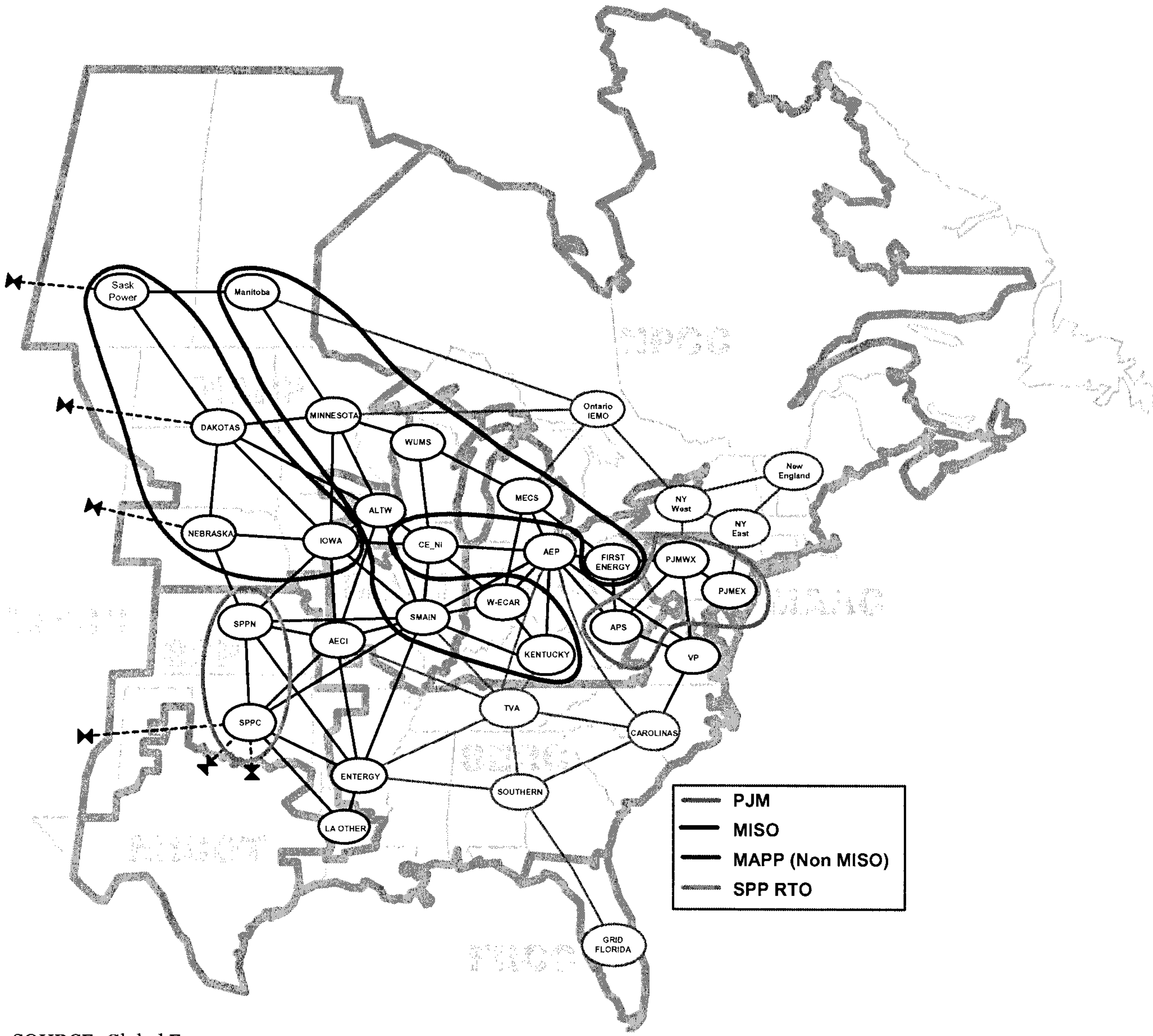
Figure 3-3
Competition Case Market Topology as of October 1, 2004



SOURCE: Global Energy.

In the Without Competition case, the market topology is similar to the Competition case except that ComEd (represented by the CE_NI zone) and AEP and DPL (both represented by the AEP zone) are modeled outside the PJM RTO and pancaked wheeling between the zones is not eliminated.

Figure 3-4
Without Competition Case Market Topology for 2004



SOURCE: Global Energy.

Other Potential Benefits of PJM Integration

In addition to the integration of supply and demand in the wholesale energy market, brought about by the reduction of seams between market areas, there are other significant benefits to RTO membership and the integration of energy markets and services in general that were not considered in this study. For example, AEP and DPL are now integrated with APS in a single spinning reserve market. For regulation services, ComEd, AEP, DPL, and APS are all members of PJM's integrated Western Zone. PJM also coordinates generation and transmission maintenance for the entire RTO as well as Available Transmission Capacity (ATC). These and other potential benefits are not captured in this analysis.

Results Summary

Global Energy's analysis supports PJM's conclusion that, in 2004, changes in supply and demand fundamentals resulted in lower PJM prices in 2004 than 2003. Global Energy quantified the production cost savings associated with the reduction of seams between these ComEd, AEP, DPL and PJM's energy markets at approximately $29.5 million for PJM in 2004 and $36.4 million for the Eastern Interconnection. Because these savings are based on the actual integration schedule for ComEd (May 2004) and AEP/DPL (October 2004), they represent savings for a partial year of integration in 2004. In order to quantify the benefits associated with a full year of integration, Global Energy performed the analysis as if ComEd, AEP, and DPL joined PJM on January 1, 2004. The estimated annualized production cost savings for PJM and the Eastern Interconnection were $69.8 million and $85.4 million, respectively.

Table 3-2
Estimated Benefits of Energy Market Integration in 2004

	2004 Production Cost Savings	
Market Area	**Savings based on 2004 PJM Integration Timeline (ComEd in May 2004 and AEP/DPL in October 2004)**	**Annualized Savings (Simulates Integration of ComEd, AEP, DPL on January 1, 2004)**
PJM	$29.5 MM	$69.8 MM
Eastern Interconnect	$36.4 MM	$85.4 MM

SOURCE: Global Energy.

RTO formation has opened the doors to broad market access for customers, not only to merchant generators and suppliers, in a more competitive market environment but also increasingly to renewable energy from wind and other sources. The annual production cost savings for the PJM expansion should continue year after year.

Appendices

Appendix A
Competition in U.S. Wholesale Power Markets

Background

Overview of Electricity Market Restructuring in the United States

The U.S. electric power industry has undergone significant changes in the past several decades, trending from a vertically integrated and cost-regulated industry toward restructured markets with competitive, market-based prices. The transition began in the 1970s when support for traditional utility regulation diminished as a result of increasing electricity prices. The passage of the Public Utility Regulatory Policies Act (PURPA) in 1978 made it possible for non-utility generators to enter the wholesale power market. PURPA was followed by the Energy Policy Act in 1992, and subsequent federal and state legislation with the goal of establishing a regulatory framework in support of competitive wholesale power markets. This section provides an overview of key federal legislative and regulatory initiatives that comprise the regulatory history of the U.S. Electric Power Industry since 1935.

Federal Power Act of 1935

The Federal Power Act (FPA) of 1935 established the guidelines for federal regulation of public utilities engaging in interstate commerce of electricity. Through this act, the Federal Power Commission (FPC) was given wider authority and became the precursor to FERC. Authority given to the FPC included the ability to:

- Issue licenses for new hydroelectric projects;
- Collect utility operational and financial data, including original investment costs and electric generation and sales data; and
- Review electric rates charged by utilities and establish their depreciation schedules.

One of the most important implications of the FPA was the requirement for utilities to charge "fair and reasonable rates." By forcing utilities to publish all rate schedules for public and government review, the FPA forced utilities to defend all rates on a cost of service basis. Charging different rates to customers became illegal, absent substantial cost justification. Further, FPA established the allowable time frame for utilities to change rate schedules.

The FPA of 1935 also outlined strict conflict of interest rules for officers and directors of public utilities engaging in interstate commerce. The FPC was terminated in 1950 when its powers were transferred to FERC. Later, some of FERC's powers were assumed by the U.S. Department of Energy.

Public Utilities Holding Company Act of 1935

Another act passed in 1935 was the Public Utilities Holding Company Act (PUHCA). Designed to work in tandem with the FPA of 1935, PUHCA sounded the death knell for the multi-tiered holding company structures, which had prevented effective regulation of public utilities, and forced utilities operating in more than one state to be heavily regulated by the Securities Exchange Commission (SEC). As a result of PUHCA, most utilities operate within a single state (or in multiple states with a contiguous service territory), which allows them exemption from a great deal of the oversight administered by the SEC.

Prior to this legislation, the U.S. electric industry had experienced significant consolidation, to the extent that only three companies controlled 45 percent of the U.S. electric market. While many states had public utility commissions, none of these agencies had significant regulatory power, especially when pitted against companies involved in commerce across state lines. Because of the lack of regulatory oversight, holding companies were able to legally buffer themselves from government regulation by separating themselves from their operating subsidiaries through multiple layers of holding companies, aligned through complex affiliate relationships. The result was that a few holding companies enjoyed substantial market power and could not be held accountable for engaging in collusive pricing strategies.

PUHCA (and FPA of 1935) was a direct result of negotiations between utility holding companies and the federal government. Utility owners agreed to provide reliable service at a regulated rate, in exchange for an exclusive service territory. Rate regulation would be the responsibility of the Federal Power Commission as established under the FPA of 1935, while the majority of inter-company financial transactions would be regulated by the SEC as outlined in PUHCA. Also, PUHCA dismantled the multi-tiered holding company structure by making it illegal to be more than twice removed from operating subsidiaries.

As a result of PUHCA, over a third of holding companies owning electricity and natural gas distribution utilities were forced by the SEC to divest such that their electric and gas services were no longer affiliated. The legislation allowed exemption from PUHCA if the holding companies operate in a single state or within contiguous states. While most holding companies have chosen to operate within a single state to qualify for PUHCA exemption, these firms are still strictly regulated by state public utility or public service commissions.

Public Utility Regulatory Policies Act – 1978

PURPA is one of five bills signed into law on November 9, 1978, as part of the National Energy Act. It is the only one remaining in force. Enacted to combat the "energy crisis," and encourage the development of alternative sources of generation, PURPA requires utilities to buy power from non-utility generating facilities that use renewable energy sources or "cogeneration," i.e., the use of steam both for heat and to generate electricity. A non-utility generating facility that meets certain ownership, operating, and efficiency criteria established by FERC is known as a Qualifying Facility or QF. The Act stipulates that electric utilities must interconnect with these QFs and buy the capacity and energy offered by the QFs at the utilities' avoided cost.

Energy Policy Act – 1992

The Energy Policy Act of 1992 (EPAct) opened access to transmission networks and exempted certain non-utilities from the restrictions of the Public Utility Holding Company Act of 1935 (PUHCA). EPAct therefore made it easier yet for non-utility generators to enter the wholesale market for electricity. While EPAct opened access to transmission networks for purposes of wholesale transactions, it did not mandate open access for retail load. The Act left it up to individual states to determine if they wanted to open access to power lines for purposes of retail sales.

The Act also created a new category of power producers, called exempt wholesale generators (EWGs). By exempting EWGs from PUHCA regulation, the law eliminated a major barrier for utility-affiliated and nonaffiliated power producers wanting to compete to build new non-rate-based power plants. EWGs differ from PURPA Qualifying Facilities (QFs) in two ways. First, they are not required to meet PURPA's utility ownership, cogeneration, or renewable fuels limitations. Second, utilities are not required to purchase power from EWGs.

In addition to giving EWGs and QFs access to distant wholesale markets, EPAct provides transmission-dependent utilities the ability to shop for wholesale power supplies, thus releasing them—mostly municipals and rural cooperatives—from their dependency on surrounding investor-owned utilities for wholesale power requirements. The transmission provisions of EPAct have led to a nationwide, open-access electric power transmission grid for wholesale transactions.

FERC Order 888 and 889 – 1996

With the passage of EPAct, Congress opened the door to wholesale competition in the electric utility industry by authorizing FERC to establish regulations to provide open access to the nation's transmission system. FERC's subsequent rules, issued in April 1996 as Order 888, are designed to increase wholesale competition in the nation's transmission system, remedy undue discrimination in transmission, and establish standards for stranded cost recovery. A companion ruling, Order 889, requires utilities to establish electronic systems to share information on a non-discriminatory basis about available transmission capacity.

FERC Order 2000 – 1999

In an effort to continue the evolution of competitive wholesale power markets, FERC Order 2000, released in December 1999, requested the formation of regional transmission organizations (RTOs). The reasons for establishing RTOs were to:

- Improve efficiencies in transmission grid management;
- Improve grid reliability;
- Remove remaining opportunities for discriminatory practices;
- Improve market performance; and
- Facilitate lighter handed regulation.

To achieve this end, the order established minimum characteristics and functions for RTOs; a collaborative process for owners and operators of interstate transmission facilities to consider and develop RTOs; a ratemaking reform process; and a schedule for public utilities to file with FERC to initiate RTO operations.

FERC's Standard Market Design Activity, 2001 – Present

Since FERC Order 2000, FERC has released proposed rule makings defining further their position on the formation of RTOs and how wholesale electricity markets should be managed. On March 15, 2002, FERC issued its notice of proposed rulemaking (NOPR) on standard market design (SMD). The purpose of this rulemaking was to establish standards for bulk wholesale market design, focusing on the establishment of RTOs while recognizing the need for flexibility to address regional differences.

Despite FERC's staunch commitment to reliable, efficient, and competitive wholesale markets, SMD has been met with mixed support. While some regions have embraced the establishment of RTOs and the standards proposed in FERC's SMD process, many utilities and state agencies—particularly those in the

South—have been reluctant to form or join RTOs. It appears that U.S. wholesale power markets will continue to be a hybrid of bilateral and/or organized RTO markets for the foreseeable future.

Table A-1
Major Milestones

1996	Order 888	Introduced concept of open access to transmission lines and open access same-time information system (OASIS).
1999	Order 2000	Introduced the concept of regional transmission organizations (RTOs); encouraged but did not require utilities to join.
2001	Price Mitigation Plan	Initial order released on April 26, 2001; applied to California starting May 29, 2001. Order extended to cover 11 western states in the WSCC.
2001	Enron Collapse	November 15, 2001, Enron's problems escalate; bankruptcy filing December 2, 2001.
2002	Supreme Court Ruling	April 4, 2002, the Supreme Court re-affirms FERC's jurisdiction in pushing ahead with its long-term policy to create a seamless national grid.
2002	FERC's Standard Market Design	Issued on March 15, 2002, proposes mandatory, universal rules covering all RTOs/ISOs.

SOURCE: Global Energy.

Defining Competition

The U.S. electric power industry did not develop according to a single plan or business model. Rather, it evolved over time in response to various local and regional needs and requirements. The regulation of the industry also evolved, changing according to local and regional needs and the politics of the time. Therefore, defining competition in the U.S. electric power industry requires a working definition of the industry itself.

It is a challenge to provide a concise definition of the U.S. electric power industry. This is largely due to the history of both the industry and the nation. Since the concept of an electric power industry was, in essence, born in this country, the model followed for the development of the industry has evolved over time.

The industry developed with two fundamentally different forms of electric utility ownership: 1) investor-owned utilities (IOUs), which operate to provide a profit to shareholders; and 2) public power agencies, organized under various governmental authorities at the city, state, and federal level. This ownership distinction has become a crucial issue in the competition debate, as the regulatory jurisdiction over electric utilities is different for these two categories of participants.

Competition is such a common, everyday occurrence in the United States that we rarely ever try to think about what it is. Each day, we make multiple decisions in a competitive environment, trading off price, convenience and quality to decide where to eat lunch, purchase gas, or buy a pair of socks. Most people don't realize it, but when the power industry began just over a century ago, the same competitive situation existed with multiple electric service companies springing up in New York City, each with its own generators and distribution wires. This quickly became cumbersome (and dangerous), and from this developed the idea of the power industry being a "natural monopoly." Cities and other political jurisdictions decided to make electric service a "franchise," giving a single, integrated electric service provider the sole right to serve all retail customers within their borders. Over time, various levels of regulation arose to prevent the electric utilities from charging "unreasonable" prices. Also, retail electricity prices were set, by regulation, at the average cost of service for each class of customer.

Over the last quarter century there has been a cycle in business regulation based on the observation that industries which in the past were perceived to be "natural monopolies" were no longer so, usually due to relatively easier entry for new suppliers, or technological advances that gave buyers better access to competitive alternatives and easier price discovery. Since the 1970s, there has been steady deregulation of many U.S. industries, including natural gas production, natural gas pipelines, railroads, long haul trucking, telecommunications, and airlines.

In the case of the electric power industry, deregulation has occurred in fits and starts, hampered by the multi-jurisdictional nature of regulation itself. Broadly speaking, the power industry has two sectors, a wholesale sector focused on transactions between entities that are not the end users, and a retail sector consisting of the ultimate end users, be they homes, commercial establishments or large industrial consumers. The wholesale sector is regulated by FERC, while the retail sector is regulated by each state's public utility commission. And the public power agencies are often exempt from many regulations.

With the context of the electric power industry now defined, we can start to define what competition means. The definition has wholesale and retail dimensions.

Retail competition occurs at the state or local level and essentially means that individual residential, commercial or industrial customers can choose their electricity supplier. These suppliers are commonly known as competitive retailers or retail electric providers. This study does not include the cost-savings or benefits associated with retail competition.

Wholesale competition occurs at the regional level and is distinguished in two ways. First, wholesale purchasers of supply (e.g. utilities, competitive retailers and other load-serving entities) and wholesale power suppliers (e.g. generators and markers) engage in arms-length negotiations that result in bilateral contracts. This approach is usually for seasonal, medium-term or longer-term supply. Second, wholesale purchasers and suppliers participate in short-term, bid-based spot markets whereby their bids and offers clear the market at various price levels throughout the day. Certain elements of wholesale power competition are shown in Table A-2.

Table A-2
Elements of Wholesale Power Competition

Wholesale Power	
Competitive Elements	**Status**
Entry by new participants	Any company with the financial resources can enter the market and sell electric power.
Access to electric transmission	New generators can get interconnected, but in some cases do not have ability to reach customers.
Functioning markets for wholesale power	Some markets organized by ISOs (ISO-NE, NYISO, PJM, MISO, ERCOT, CAISO), others have active bilateral day-ahead markets. Still others have little liquidity.

SOURCE: Global Energy.

Appendix B
Modeling Tools

EnerPrisė™ Strategic Planning *powered by MIDAS Gold®* was utilized to measure and analyze the consumer value of competition.

Strategic Planning includes multiple modules for an enterprise-wide strategic solution. These modules are:

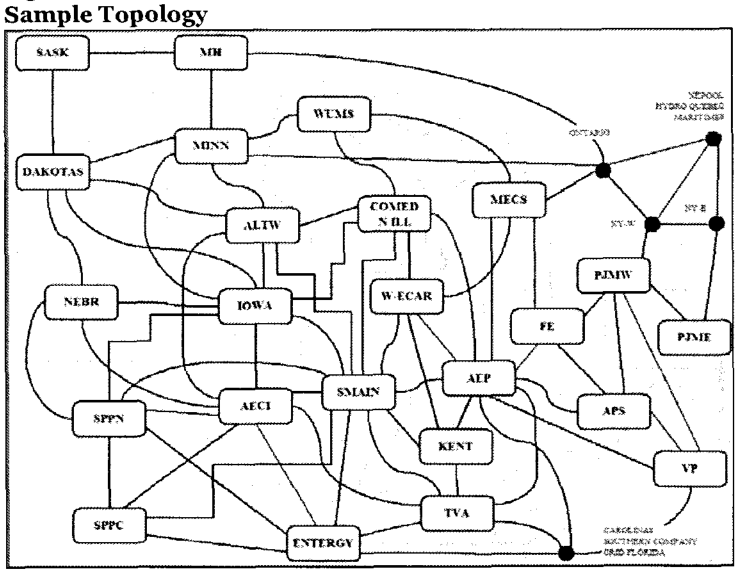
- Markets;
- Portfolio;
- Financial; and
- Risk.

Strategic Planning is an integrated, fast, multi-scenario zonal market model capable of capturing many aspects of regional electricity market pricing, resource operation, and asset and customer value. The markets and portfolio modules are hourly, multi-market, chronologically correct market production modules used to derive market prices, evaluate power contracts, and develop regional or utility-specific resource plans. The financial and risk modules provide full financial results and statements and decision-making tools necessary to value customers, portfolios and business unit profitability.

Markets Module

Markets Module generates zonal electric market price forecasts for single and multi-market systems by hour and chronologically correct for 30 years. Prices may be generated for energy only, bid- or ICAP-based bidding processes. Prices generated reflect trading between transaction groups where transaction group may be best defined as an aggregated collection of control areas where congestion is limited and market prices are similar. Trading is limited by transmission paths and constraints quantities.

Figure B-1
Sample Topology



SOURCE: Global Energy.

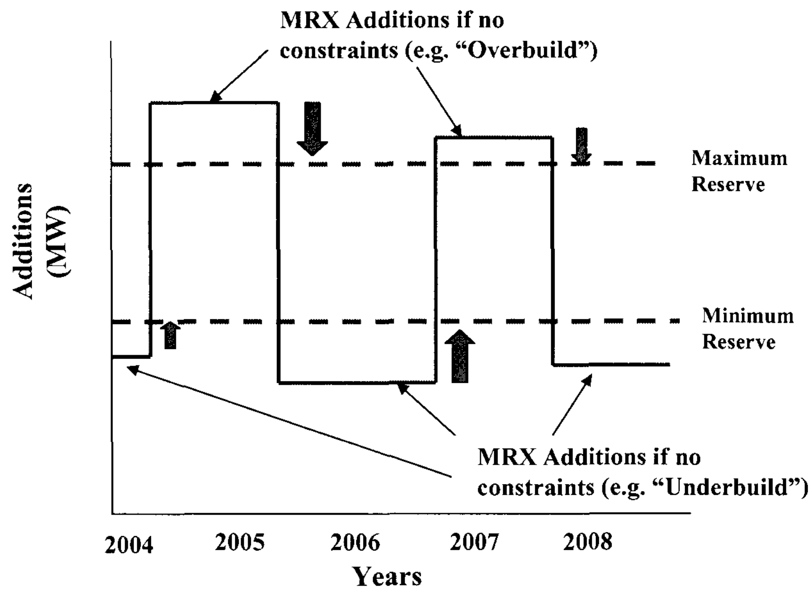
The database is populated with Global Energy Intelligence – Market Ops information.

- Operational information provided for over 10,000 generating units.
- Load forecasts by zone (where zone may be best defined as utility level) and historical hourly load profiles.
- Transmission capabilities.
- Coal price forecast by plant with delivery adders from basin.
- Gas price forecast from Henry Hub with basis and delivery adders.

When running the simulation in Markets Module, the main process of the simulation is to determine hourly market prices. Plant outages are based on a unit derate and maintenance outages may be specified as a number of weeks per year or scheduled.

The market based resource expansion algorithm builds resources by planning region based on user-defined profitability and/or minimum and maximum reserve margin requirements in determining prices. In addition, strategic retirements are made of non-profitable units based on user-defined parameters.

Figure B-2
MRX Decision Basis



SOURCE: Global Energy.

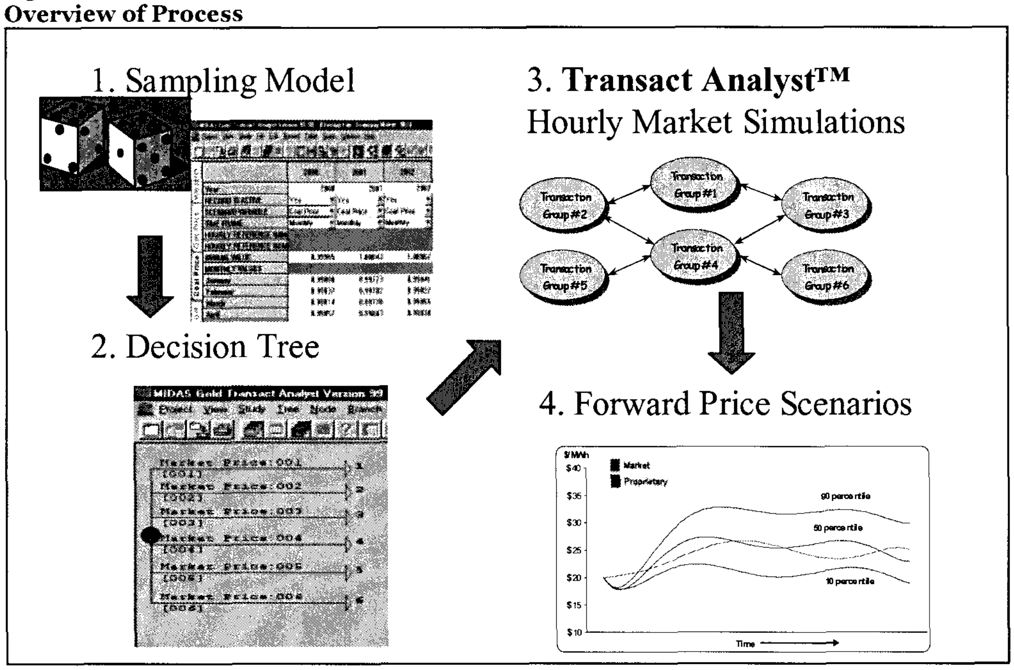
The Markets Module simulation process performs the following steps to determine price:

- Hourly loads are summed for all customers within each Transaction Group;
- For each Transaction Group in each hour, all available hydro power is used to meet firm power sales commitments;
- For each Transaction Group and Day Type, the model calculates production cost data for each dispatchable thermal unit and develops a dispatch order;
- The model calculates a probabilistic supply curve for each Transaction Group considering forced and planned outages;

- Depending on the relative sum of marginal energy cost + transmission cost + scarcity cost between regions, the model determines the hourly transactions that would likely occur among Transaction Groups; and
- The model records and reports details about the generation, emissions, costs, revenues, etc. associated with these hourly transactions.

Strategic Planning has the functionality of developing probabilistic price series by using a four-factor structural approach to forecast prices that captures the uncertainties in regional electric demand, resources and transmission. Using a Latin Hypercube-based stratified sampling program, Strategic Planning generates regional forward price curves across multiple scenarios. Scenarios are driven by variations in a host of market price "drivers" (e.g., demand, fuel price, availability, hydro year, capital expansion cost, transmission availability, market electricity price, reserve margin, emission price, electricity price and/or weather) and takes into account statistical distributions, correlations, and volatilities for three time periods (i.e., Short-Term *hourly*, Mid-Term *monthly*, and Long-Term *annual*) for each transact group. By allowing these uncertainties to vary over a range of possible values a range or distribution of forecasted prices are developed.

Figure B-3
Overview of Process



SOURCE: Global Energy.

Portfolio Module

Once the price trajectories have been completed in the Markets Module, the Portfolio Module may be used to perform utility or region specific portfolio analyses. Simulation times are faster and it allows for more detailed operational characteristics for a utility specific fleet. The generation fleet is dispatched competitively against pre-solved market prices from the Markets Module or other external sources. Native load may also be used for non-merchant/regulated entities with a requirement to serve.

Operates generation fleet based on unit commitment logic which allows for plant specific parameters of:

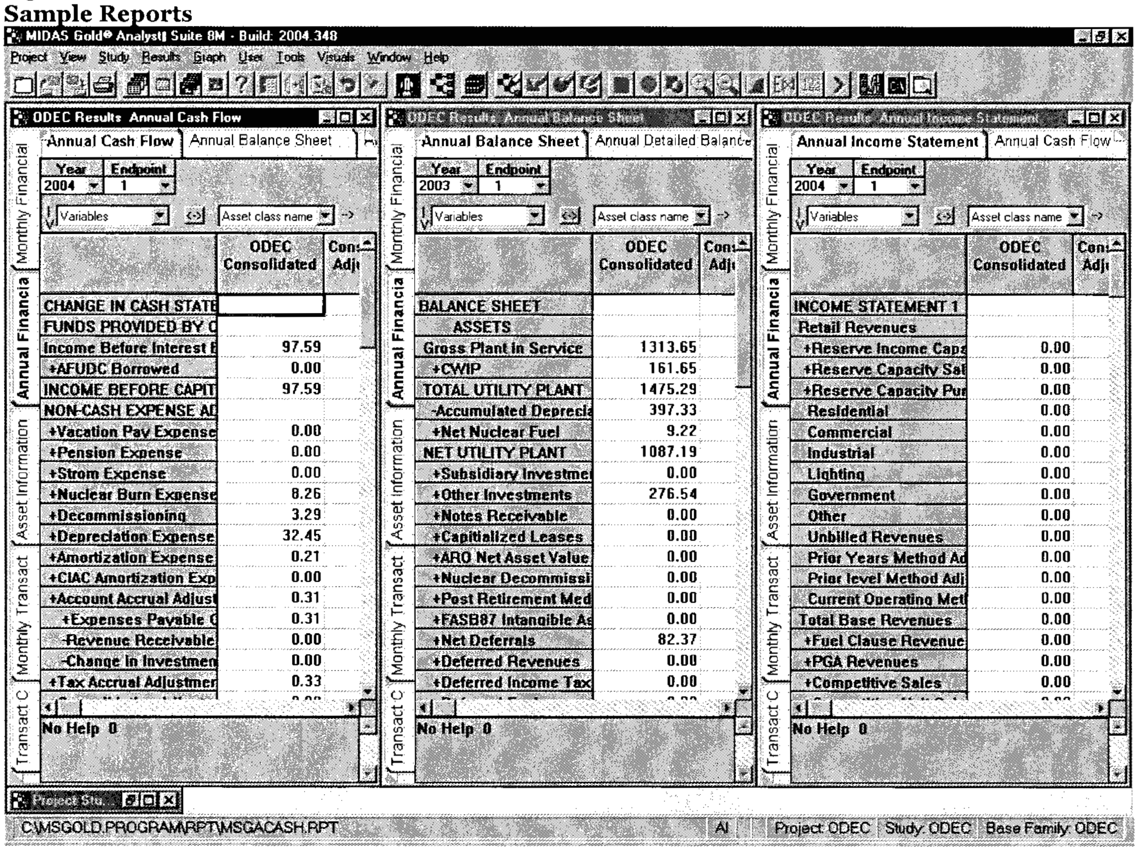
- Ramp rates;
- Minimum/maximum run times; and
- Start up costs.

The decision to commit a unit may be based on one day, three day, seven day and month criteria. Forced outages may be based on Monte Carlo or frequency duration with the capability to perform detailed maintenance scheduling. Resources may be de-committed based on transmission export constraints. Portfolio Module has the capability to operate a generation fleet against single or multiple markets to show interface with other zones. In addition, physical, financial, and fuel derivatives with pre-defined or user-defined strike periods, unit contingency, replacement policies, or load following for full requirement contracts are active.

Financial Module

The Financial Module allows the user the ability to model other financial aspects regarding costs exterior to the operation of units and other valuable information that is necessary to properly evaluate the economics of a generation fleet. The Financial Module produces bottom-line financial statements to evaluate profitability and earnings impacts.

Figure B-4
Sample Reports



SOURCE: Global Energy.

Risk Module

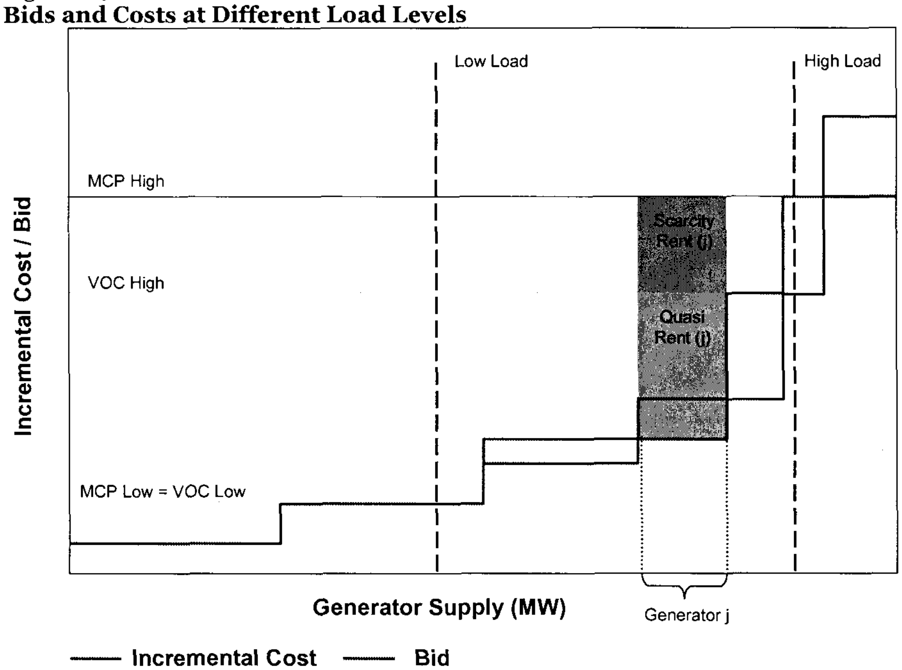
Risk Module provides users the capability to perform stochastic analyses on all other modules and review results numerically and graphically. Stochastics may be performed on both production and financial variables providing flexibility not available in other models.

Bidding Behavior

Power prices are formed each hour, based on the bids submitted by individual generators. In general, the marginal unit determines the market clearing price where a unit's bid includes variable costs such as fuel and variable O&M. In practice, generators employ a wide variety of strategies that are consistent with the cost and load serving characteristics of their generating portfolio. These entities forecast how tight the supply/demand situation is to assess the pricing opportunities in the market, and will price their output in a manner that reflects not only the costs of individual units, but also the cost of operating the entire portfolio, including the most expensive units needed to meet load.

During some of high load hours of the study period, it was observed there was barely sufficient generation to meet loads. At this point, the generator priced electricity at levels above their variable costs. During these times, the revenue collected by individual generators increases with the scarcity present in the market and can, over time, contribute significantly to the coverage of financing and other fixed costs. The collection of scarcity revenue is consistent with a functioning market, providing a price signal to the market that additional resources may be necessary.

Figure B-5
Bids and Costs at Different Load Levels



SOURCE: Global Energy.

Figure B-5 is a graphical representation of how scarcity relates to the supply/demand balance. The lower curve in the diagram represents the variable costs (including incremental fuel costs and variable O&M) for different generators in an hour, stacked from lowest to highest cost.

Baseloaded low cost plants, such as coal and nuclear facilities, have little incentive to bid above their short run marginal costs as they will seldom or never be at the margin (but will nevertheless receive the market clearing price). During low load hours, when there is ample supply relative to load, one might expect generators to be price-takers, bidding their variable operating cost (VOC). The market clearing price is set by the cost of the last unit dispatched. In our example, the second dispatch block sets MCP_{Low} during a low load hour.

As load increases to the point where supply just barely covers load, the scarcity (or rent) increases. As demand increases, there are fewer alternative sources of generation, and the higher cost generators have opportunities to bid above their variable costs. This above-VOC bidding is represented by the upper curve in the figure; price is then set above the costs of the last unit dispatched, as shown by MCP_{High} in Figure B-5 during a high load hour.

Rents are defined as the revenues received by a market participant in excess of that participant's marginal costs. These rents are available to cover both fixed and financing costs (including required returns on equity). Even during low-load periods significant rents may exist. For example, in Figure B-5, the owners of generation in the first block face variable costs below the market clearing price. Unit operating constraints and outages may also result in significant scarcity even during low load hours.

To further illustrate the economic rents collected by a generator, Figure B-5 shows the total rent collected by generator "j." The total rent is the generator's output times the difference between the price and its VOC, or the sum of the two rectangular shaded areas in Figure B-5. The upper rectangular area is what is typically described as the scarcity rent; it reflects the price increase that is due to the ability of the marginal generator to bid in excess of its marginal costs.

Total scarcity rents—which are shared by all generators—are equal to the total generation in the market multiplied by ($MCP_{High} - VOC_{High}$).

The lower rectangular area is sometimes referred to as quasi-rents—it is a rent that appears even if all participants are acting as price-takers. For the entire market, total quasi-rents are represented as the area above the VOC curve and below the VOC for the marginal dispatch block. Thus, in Figure B-5 it is the area below VOC_{High} and above the VOC curve.

Quasi-rents appear under almost all market conditions. Even in the low-load case, the first dispatch block earns quasi-rents. Quasi-rents are an important source of revenue necessary to pay start-ups, minimum-run costs, fixed operating costs, and the financial expenses associated with generating facilities. However, marginal units do not earn quasi-rents. These units instead depend on scarcity rents resulting from bidding above short run marginal costs to provide the necessary coverage of fixed and financing costs.

Appendix C
Benefits & Efficiency Improvements

Table C-1
Nuclear Plants Purchased/Sold

	Date of Sale
Three Mile Island	December 1999
Clinton	December 1999
Oyster Creek	August 2000
Vermont Yankee	March 2002
Millstone	March 2001
Fitzpatrick	November 2000
Pilgrim	July 1999
Salem	January 2001
Peach Bottom	January 2001
Hope Creek	January 2001
Indian Point	September 2001
Nine Mile Point	November 2001
Seabrook	December 2002
Ginna	June 2004
Kewaunee	Tentative

SOURCE: Global Energy.

Table C-2
Nuclear Plants included in Analysis (2004 MW)

Plant Name	Summer Capacity MW
Arkansas Nuclear One	1,776
Beaver Valley	1,665
Braidwood	2,349
Browns Ferry	2,226
Brunswick (NC)	1,720
Brunswick (NC)	1,631
Byron (IL)	2,412
Callaway (MO)	1,143
Calvert Cliffs	1,805
Catawba	2,258
Clinton (IL)	1,116
Columbia Generating	1,170
Comanche Peak	2,208
Cooper	758
Crystal River	834
Davis Besse	873
Diablo Canyon	2,174

Table continued on next page.

Plant Name	Summer Capacity MW
Donald C Cook	2,078
Dresden	1,700
Duane Arnold	578
Edwin I Hatch	1,726
Fermi	1,111
Fort Calhoun	476
Ginna	498
Grand Gulf	1,210
H B Robinson	683
Harris (NC)	900
Hope Creek	1,131
Indian Point 2	1,040
Indian Point 3	997
James A Fitzpatrick	840
Joseph M Farley	1,675
Kewaunee	574
La Salle	2,259
Limerick	2,268
McGuire	2,200
Millstone	2,064
Monticello (MN)	597
Nine Mile Point (NY)	1,756
North Anna	1,842
Oconee	2,538
Oyster Creek (NJ)	619
Palisades (MI)	779
Palo Verde	3,869
Peach Bottom	2,221
Perry (OH)	1,265
Pilgrim	667
Point Beach	1,012
Prairie Island	1,049
Quad Cities (EXELON)	1,710
Riverbend	980
Salem (NJ)	2,361
San Onofre	2,150
Seabrook	1,161
Sequoyah (TN)	2,239
South Texas	2,529
St Lucie	1,678
Surry	1,625

Table continued on next page.

Plant Name	Summer Capacity MW
Susquehanna	2,301
Three Mile Island	816
Turkey Point	1,386
V C Summer	966
Vermont Yankee	506
Vogtle (GA)	2,297
Waterford 3	1,093
Watts Bar Nuclear	1,128
Wolf Creek (KS)	1,170

SOURCE: Global Energy.

Table C-3
Refueling Outages (Total # of days per year)

	2004	2003	2002	2001	2000	1999
Traditional	1,618	1,978	1,648	1,481	1,822	1,903
Competitive	401	307	386	332	390	564

SOURCE: Global Energy.

As identified from NRC outage reporting and Global Energy's assessment to determine if outage was related to refueling.

Table C-4
Nuclear Fixed and Variable O&M ($/MWh)

Adjusted for inflation	2004	2003	2002	2001	2000	1999
Industry	10.17	11.88	11.69	11.67	9.92	11.09
Traditional	10.03	11.91	11.80	11.03	9.49	10.16
Competitive	9.92	10.77	10.28	12.61	11.25	14.85

SOURCE: Global Energy.

Table C-5
Coal Fixed and Variable O&M ($/MWh)

Adjusted for Inflation	2004	2003	2002	2001	2000	1999
Traditional	3.29	3.89	4.27	4.32	3.54	3.84
Competitive	3.43	3.98	3.88	4.58	3.49	3.96
All	3.33	3.92	4.15	4.39	3.52	3.88

SOURCE: Global Energy.

Table C-6
Coal Operational Statistics

Heat Rate (Btu/kWh)	2004	2003	2002	2001	2000	1999
Traditional	10,885	11,470	11,249	11,136	11,312	11,243
Competitive	11,717	11,067	14,343	13,269	12,599	12,469
All	11,175	11,320	12,467	11,961	11,789	11,680

SOURCE: Global Energy.

Table C-7
Coal Generation Fleet (2004 MW)

Unit Name	Summer Capacity MW
A B Brown	500
Abitibi Consolidated Snowflake	68
ACE Cogeneration Co	101
AES BV Partners Beaver Valley	146
AES Cayuga	306
AES Greenidge	162
AES Hawaii Inc	180
AES Shady Point Inc	320
AES Somerset LLC	684
AES Thames Inc	181
AES Warrior Run Cogeneration F	180
Ag Processing Inc	9
Albright	283
Allen (TN)	738
Altavista	63
Ames (IA AMES)	103
Antelope Valley	904
Argus Cogeneration Plant	50
Armstrong Power Station	343
Asbury	213
Asheville	392
Ashtabula	244
Avon Lake	715
B C Cobb	501
B L England	439
Bailly	480
Baldwin Energy Complex	1,761
Barry	1,658
Bay Front	75
Bay Shore	621
Belews Creek	2,240
Belle River	1,260
Big Bend (FL)	1,712
Big Brown	1,130
Big Cajun 2	1,730
Big Sandy	1,060
Big Stone	456

Table continued on next page.

Unit Name	Summer Capacity MW
Biron Mill	62
Black Dog	284
Black River Power	53
Blount Street	194
Boardman (OR)	557
Bonanza	460
Bowater Newsprint Calhoun Operations	66
Bowen	3,262
Brandon Shores	1,286
Brayton PT	1,531
Bremo Bluff	227
Bridgeport Harbor (PSEG)	524
Bruce Mansfield	2,360
Buck (NC)	369
Bull Run (TN)	868
Burlington (IA)	212
C P Crane	385
Canadys Steam	396
Cane Run	563
Canton North Carolina	53
Cape Fear	316
Capitol Heat & Power	2
Cardinal	1,800
Carneys Point Generating Plant	237
Cayuga	990
Cedar Bay Generating Co LP	250
Cedar Rapids	260
Chalk Point	1,907
Charles R Lowman	551
Cherokee (CO)	717
Chesapeake	595
Chesterfield	1,229
Cheswick Power Plant	562
Cholla	995
Clay Boswell	964
Cliffside	760
Clifty Creek	1,247
Clinch River	690
Clinton (IA ADM)	31

Table continued on next page.

Unit Name	Summer Capacity MW
Clover	882
Coal Creek	1,089
Cogeneration South	90
Cogentrix of Richmond Inc	190
Colbert	1,173
Coleto Creek	632
Colstrip	2,094
Columbia (WI)	1,074
Columbus Street	64
Colver Power Project	110
Comanche (CO)	660
Conemaugh	1,700
Conesville	1,925
Cope	422
Cornell Univ Central Heating	8
Coronado	785
Council Bluffs	806
Coyote	427
Craig (CO)	1,264
Crawford (IL)	532
Crist	996
Cromby Generating Station	345
Cross	1,160
Crystal River	2,302
Cumberland (TN)	2,462
D E Karn	1,791
Dallman	372
Dan River (NC)	276
Danskammer Generating Station	500
Dave Johnston	762
Decatur (IL ADM)	335
Deepwater (NJ)	220
Deerhaven	313
Dolet Hills	650
Duck Creek	366
Dunkirk Generating Station	607
E C Gaston	1,890
E D Edwards	740
E W Brown	711

Table continued on next page.

Unit Name	Summer Capacity MW
East Bend	600
Eastlake	1,222
Eckert Station	357
Eddystone Generating Station	1,341
Edge Moor	704
Edgewater (WI)	836
Edwardsport	160
Eielson Air Force Base Central	20
Elmer Smith	413
Elrama Power Plant	474
Endicott Generating	50
F B Culley	406
Fayette Power PRJ	1,605
Fisk Street	326
Flint Creek (AR)	480
Fort Martin	1,107
Four Corners	2,040
Frank E Ratts	244
G F Weaton Power Station	112
G G Allen	1,140
Gallatin (TN)	976
Gavin	2,600
General Chemical	30
Genoa No3	352
George Neal 1 4	950
Gerald Gentleman	1,365
Ghent	1,968
Gibbons Creek	462
Gibson Station	3,131
Glen Lyn	325
Gorgas 2 & 3	1,288
Grant Town	80
Grda 1 & 2	1,010
Green Bay West Mill	101
Green River (KY)	232
Greene County (AL)	517
H B Robinson	174
H T Pritchard/Eagle Valley	338
Hammond	846

Table continued on next page.

Unit Name	Summer Capacity MW
Harding Street	704
Harllee Branch	1,607
Harrington	1,066
Harrison (WV)	1,920
Hatfields Ferry Power Station	1,369
Havana	683
Hawthorne (MO)	565
Hayden	446
Healy	25
Hennepin Power Station	289
Herbert A Wagner	1,000
High Bridge	269
Holcomb Unit No 1	331
Homer City Station	1,884
Hoot Lake	156
Hudson Generating Station	991
Hugh L Spurlock	850
Hugo (OK)	450
Hunter	1,315
Huntington (UT)	895
Huntley Generating	712
Iatan	670
Independence (AR)	1,651
Indiantown Cogeneration Facili	330
Intermountain	1,778
Irvington	423
J C Weadock	310
J H Campbell	1,435
J K Spruce	555
J M Stuart	2,340
J R Whiting	326
J Sherman Cooper	341
J T Deely	830
Jack McDonough	517
Jack Watson	1,041
James H Miller Jr	2,686
James River Power St	236
Jefferies	398
Jeffrey Energy Center	2,226

Table continued on next page.

Unit Name	Summer Capacity MW
Jim Bridger	2,120
John E Amos	2,900
John P Madgett	374
John Sevier	704
Johnsonville (TN)	1,206
Joliet 29	1,036
Joppa Steam	1,014
Juniata Locomotive Shop	4
Kammer	600
Kanawha River	390
Keystone (PA)	1,700
Killen Station	600
Kincaid Generation LLC	1,168
King	571
Kingston	1,434
Kodak Park Site	200
Kraft	317
Kyger Creek	1,025
L V Sutton	613
La Cygne	1,362
Labadie	2,300
Lake Road (MO)	152
Lake Shore	230
Lansing	316
Lansing Smith	351
Laramie River 1 3	1,668
Lawrence Ec	572
Lee	407
Leland Olds 1 & 2	669
Limestone	1,602
Lon Wright	120
Louisa	700
Lovett	432
Luke Mill	60
M L Hibbard	41
M L Kapp	236
Marshall (MO)	26
Marshall (NC DUKE)	2,090
Martin Drake	259

Table continued on next page.

Unit Name	Summer Capacity MW
Martin Lake	2,250
Marysville	200
Mayo	745
McIntosh (GA SAVNAH)	155
McMeekin	250
Mead Paper Division	78
Meramec	876
Mercer Generating Station	648
Merom	1,000
Merrimack	433
Miami Fort	1,243
Michigan City	589
Mill Creek (KY)	1,470
Milton R Young	705
Mirant Birchwood Power Facilit	237
Mitchell (GA)	153
Mitchell (WV)	1,600
Mitchell Power Station	359
Mohave (NV)	1,580
Monroe (MI)	3,020
Monticello (TX)	1,880
Montour	1,543
Montrose	510
Mountaineer	1,300
MT Poso Cogeneration	52
Mt. Storm	1,587
Muscatine	280
Muskegon	37
Muskingum River	1,365
Muskogee	1,666
Natrium Plant	123
Naughton	700
Navajo	2,250
Neal South	644
Nearman Creek	235
Nebraska City	632
Nelson Dewey	218
New Castle Plant	413
New Madrid	1,160

Table continued on next page.

Unit Name	Summer Capacity MW
Newton (IL)	1,110
Niles (OH ORION)	216
North Branch (WV)	74
North Omaha	663
North Valmy	522
Northeastern	1,380
Northeastern Power Cogeneration Facility	50
Nucla	100
O H Hutchings	365
Ottumwa (IA IPL)	720
P H Glatfelter Co	50
Paradise	2,159
Pawnee	505
Petersburg (IN)	1,664
Phil Sporn	1,020
Picway	90
Pirkey	580
Plains Escalante	247
Plant 3 McIntosh	531
Pleasant Prairie	1,224
Pleasants	1,065
Polk Station	255
Port of Stockton District Ener	44
Port Washington	160
Portland (PA)	401
Potomac River	482
Powerton	1,538
PPL Brunner Island	1,434
Prairie Creek 1 4	197
Presque Isle	618
Pulliam	396
Purdue University	38
Quindaro	208
R D Morrow	400
R E Burger	406
R Gallagher	560
Rawhide	270
Ray D Nixon	208
Red Hills Generating Facility	440

Table continued on next page.

Unit Name	Summer Capacity MW
Reid Gardner	556
Richard H Gorsuch	212
River Rouge	735
Riverbend (NC)	454
Riverside (MN)	382
Rochester 7	252
Rockport	2,600
Rodemacher	963
Rollin Schahfer	1,625
Roxboro	2,462
Roy S Nelson	1,399
Rush Island	1,166
Salem Harbor	742
San Juan	1,643
San Miguel	391
Sandow	390
Sandow No 4	554
Scherer	3,430
Seminole (FL)	1,316
Seward	520
Shawnee (KY)	1,330
Shawville	597
Sheldon (NE)	225
Sherburne County	2,292
Sibley (MO)	502
Sikeston	233
Sioux	950
SIPC Marion	272
Sixth Street (IA)	74
Sooner	1,019
South Oak Creek	1,135
Southampton	67
Southeast Missouri State Univ	6
Southwest	222
Springerville Generating Station	800
St Clair	1,662
St Johns River Power	1,252
Stanton Energy Center	886
State Line Energy	515

Table continued on next page.

Unit Name	Summer Capacity MW
Stockton Cogeneration Co	54
Sunbury Generation LLC	361
T B Simon Power Plant	55
Taconite Harbor Energy Center	225
Tanners Creek	980
Tecumseh Ec	243
Tenn Eastman Division A Division of East	194
Tes Filer City Station	65
Thomas Hill	1,120
Tolk	1,080
TransAlta Centralia Generation	1,405
Trenton Channel	730
Trimble Station (LGE)	512
Txi Riverside Cement	22
Unc Chapel Hill Cogeneration	24
University of Alaska Fairbanks	9
University of Iowa Main	21
University of Missouri Columbia	51
University of Northern Iowa	8
University of Notre Dame	21
Urquhart	94
Utility Plants Section	18
Uw Madison Charter St Plant	6
Valley (WI)	267
Valmont	186
Vanderbilt University	11
Victor J Daniel Jr	1,050
W A Parish	3,673
W H Sammis	2,220
W H Weatherspoon	176
W H Zimmer	1,300
W N Clark	43
W S Lee	370
Wabash River	668
Walter C Beckjord	1,118
Wansley (GPC)	1,783
Warrick	678
Wateree	700
Watts Bar Fossil	0

Table continued on next page.

Unit Name	Summer Capacity MW
Waukegan	789
Waupun Correctional Inst CTR	1
Welsh Station	1,584
Weston	490
White Bluff	1,620
Widows Creek	1,610
Will County	761
William C Dale	198
Williams (SC SCGC)	615
Willow Island	235
Winyah	1,155
Wood River (IL)	588
Wyandotte (MI)	72
Wyodak	335
Yates	1,295

SOURCE: Global Energy.

Table C-8
Chained Consumer Price Index for Energy

Series ID: SUUR0000SA0E

Not Seasonally Adjusted

Area: U.S. city average

Item: Energy

Base Period: December 1999=100

Year	1999	2000	2001	2002	2003	2004
Jan		100.2	116.8	98.6	112.4	121.2(U)
Feb		103.7	116.4	97.8	118.9	123.9(U)
Mar		108.9	114.4	101.9	125.4	125.8(U)
Apr		107.8	117.5	107.9	121.5	128.1(U)
May		108	123.7	108.5	118.1	134.7(U)
Jun		115.3	124.7	110.4	120.6	140.2(U)
Jul		115.4	117.4	110.9	120.9	137.6(U)
Aug		111.9	114.8	111.2	124.4	136.9(U)
Sep		115.9	117.9	111.4	128	136.0(U)
Oct		114	108.7	110.7	120.9	138.0(U)
Nov		113.4	102.6	110.3	117.4	138.5(U)
Dec	100	112.6	98.3	108.6	116.4	134.6(U)
Annual		110.6	114.4	107.4	120.4	133.0(U)

SOURCE: U. S. Department of Labor, Bureau of Labor Statistics.

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Proactive Planning and Valuation of Transmission Investments in Restructured Electricity Markets*

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Abstract

Traditional methods of evaluating transmission expansions focus on the social impact of the investments based on the current generation stock. In this paper, we evaluate the social welfare implications of transmission investments based on equilibrium models characterizing the competitive interaction among generation firms whose decisions in generation capacity investments and production are affected by both the transmission investments and the congestion management protocols of the transmission system operator. Our analysis shows that both the magnitude of the welfare gains associated with transmission investments and the location of the best transmission expansions may change when the generation expansion response is taken into consideration. We illustrate our results using a 30-bus network example.

Key words: Cournot-Nash equilibrium, market power, mathematical program with equilibrium constraints, network expansion planning, power system economics, proactive network planner.

JEL Classifications: D43, L13, L22, L94.

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1. INTRODUCTION

Within the past decade, many countries – including the US – have restructured their electric power industries, which essentially have changed from one dominated by vertically integrated regulated monopolies (where the generation and the transmission sectors were jointly planned and operated) to a deregulated industry (where generation and transmission are both planned and operated by different entities). Under the integrated monopoly structure, planning and investment in generation and transmission, as well as operating procedures, were closely coordinated through an integrated resource planning process that accounted for the complementarity and substitutability between the available resources in meeting reliability and economic objectives. The vertical separation of the generation and transmission sectors has resulted in a new operations and planning paradigm where planning and investment in the privately owned generation sector is driven by economic considerations in response to market prices and incentives. The transmission system, on the other hand, is operated by independent transmission organizations that may or may not own the transmission assets. Whether the transmission system is owned by the system operator as in the UK or by separate owners as in some parts of the US, the transmission system operator plays a key role in assessing the needs for transmission investments from reliability and economic perspectives and in evaluating proposed investments in transmission. With few exceptions, the primary drivers for transmission upgrades and expansions are reliability considerations and interconnection of new generation facilities. However, because the operating and investment decisions by generation companies are market driven, valuation of transmission expansion projects must also anticipate the impact of such investments on market prices and demand response. Such economic assessments must be carefully scrutinized since market prices are influence by a variety of factors including the ownership structure of the generation sector, the network topology, the distribution and elasticity of demand, uncertainties in demand, as well as generation and network contingencies.

Existing methods for assessing the economic impact of transmission upgrades focus on the social impact of the investments, in the context of a competitive market based on locational marginal pricing (LMP), given the current generation stock. These assessments typically ignore market power effects and potential strategic response by generation investments to the transmission upgrades. For example, the Transmission Economic Assessment Methodology (TEAM) developed by the California ISO (2004) is based on the "gains from trade" principle (see (Sheffrin, 2005)), which ignores possible distortion due to market power. In this paper, we evaluate the social-welfare implications of transmission investments based on equilibrium models characterizing the competitive interaction among generation firms whose decisions in generation capacity investments and production are affected by both the transmission investments and the congestion management protocols of the transmission system operator. In particular, we formulate a three-period model for studying how the exercise of local market power by generation firms affects the equilibrium between the generation and the transmission investments and, in this way, the valuation of different transmission expansion projects. In our model, we determine the social-welfare implications of transmission investments by solving a simultaneous Nash-Cournot game that characterizes the market equilibrium with respect to production quantities and prices. Our model accounts for the transmission network constraints, through a lossless DC approximation of Kirchoff's laws, as well as for demand uncertainty and for generation and transmission contingencies. Generation firms are assumed to choose their output levels at each generation node so as to maximize profits given the demand functions, the production decisions of their rivals and the import/export decisions by the system operator who is charged with maintaining network feasibility while maximizing social welfare. Assuming linear demand functions and quadratic generation cost functions the simultaneous set of KKT conditions characterizing the market equilibrium is a Linear Complementarity Problem (LCP) for which we can compute a unique solution.

In this paper, we present three alternative valuation approaches for transmission investments. We compare the economic impact of transmission investments under three valuation paradigms:

- A "proactive" network planner (i.e., a network planner who plans transmission investments in anticipation of both generation investments, so that it is able to induce a more socially-efficient Nash equilibrium of generation capacities, and spot market operation),
- An integrated-resources planner (i.e., a network planner who co-optimizes generation and transmission expansions), and
- A "reactive" network planner (i.e., a network planner who assumes that the generation capacities are given – and, in this way, ignores the interrelationship between the transmission and the generation investments – and determines the social-welfare impact of transmission expansions based only on the changes they induce in the spot market equilibrium).

We show that the optimal network upgrade (as measured by the increase in gross social welfare, not counting investment costs) under the proactive planner paradigm is dominated by the comparable optimal upgrade under integrated-resources planning, but dominates the outcome of the optimal upgrade under the reactive network planner paradigm. In other words, proactive network planning can recoup some of the welfare lost due to the unbundling of the generation and the transmission investment decisions by proactively expanding transmission capacity. Conversely, we show that a reactive network planner foregoes this opportunity. We illustrate our results using a stylized 30-bus system with six generation firms.

The concept of a proactive network planner was formerly proposed by Craft (1999) in her doctoral thesis. However, Craft only studied the optimal network expansion in a 3-node network that presented very particular characteristics. Specifically, Craft's work assumes that only one line is congested (and only in one direction), only one node has demand, energy market is perfectly competitive, and transmission investments are not lumpy. These strong, and quite unrealistic, assumptions make Craft's results hard to apply to real transmission systems.

While some authors have considered the effect of the exercise of local market power on network planning, none of them have explicitly modeled the interrelationship between the transmission and the generation investment decisions.[1] In (Cardell et al., 1997), (Joskow and Tirole, 2000), (Oren, 1997), and (Stoft, 1999), the authors study how the exercise of market power can alter the transmission investment incentives in a two- and/or three-node network in which the entire system demand is concentrated in only one node. The main idea behind these papers is that if an expensive generator with local market power is requested to produce power as result of network congestion, then the generation firm owning this generator may not have an incentive to relieve congestion. Borenstein et al. (2000) present an analysis of the relationship between transmission capacity and generation competition in the context of a two-node network in which there is local demand at each node. The authors argue that relatively small transmission investment may yield large payoffs in terms of increased competition. Bushnell and Stoft (1996) propose to grant financial rights (which are tradable among market participants) to transmission investors as reward for the transmission capacity added to the network and suggest a transmission-rights allocation rule based on the concept of feasible dispatch. They prove that, under

[1] In Latorre et al. (2003), the authors present a comprehensive list of the models on transmission expansion planning appearing in the literature. However, none of the over 100 models considered in that literature review explicitly considers the interrelationship between the transmission and the generation investment decisions.

certain circumstances, such a rule can eliminate the incentives for a detrimental grid expansion. However, these conditions are very stringent. Joskow and Tirole (2000) analyze the Bushnell-and-Stoft's model under assumptions that better reflect the physical and economic attributes of real transmission networks. They show that a variety of potentially significant performance problems then arise.

Some other authors have proposed more radical changes to the transmission power system. Oren and Alvarado (see (Alvarado and Oren, 2002) and (Oren et al., 2002)), for instance, propose a transmission model in which a for-profit independent transmission company (ITC) owns and operates most of its transmission resources and is responsible for operations, maintenance, and investment of the whole transmission system. Under this model, the ITC has the appropriate incentives to invest in transmission. However, the applicability of this model to actual power systems is very complicated because this approach requires the divestiture of all transmission assets.

Recently, Murphy and Smeers (2005) have proposed a detailed two-period model of investments in generation capacity in restructured electricity systems. In this two-stage game, generation investment decisions are made in a first stage while spot market operations occur in the second stage. Accordingly, the first-stage equilibrium problem is solved subject to equilibrium constraints. However, this model does not take into consideration the transmission constraints generally present in network planning problems. Thus, since our paper focus on the social-welfare implications of transmission investments, we make use of a simplified version of the two-period generation-capacity investment model while still solving the generation-capacity equilibrium problem as an optimization problem subject to equilibrium constraints.

The rest of this paper is organized as follows. Section 2 describes the proposed transmission investment model. In Section 3, we compare the valuation process of the transmission investments under the proactive network planning paradigm with both the valuation process under integrated-resources planning and the valuation process under the reactive network planning paradigm. Section 4 illustrates the theoretical results presented in the previous section using a 30-bus network example. Conclusions are presented in Section 5.

2. THE PROACTIVE TRANSMISSION INVESTMENT VALUATION MODEL

We introduce a three-period model for studying how generation firms' local market power affects both the firms' incentives to invest in new generation capacity and the valuation of different transmission expansion projects. The basic idea behind this model is that the interrelationship between the generation and the transmission investments affects the social value of the transmission capacity.

2.1 Assumptions

The model assumes a general network topology, as in a typical power-flow formulation, with possible congestion on multiple lines. To simplify the formulation, we assume, however, that all nodes are both demand and generation nodes and that all generation capacity at a node is owned by a single firm. Generation firms are allowed to exercise local market power and their interaction is characterized through Cournot competition as detailed below.

The model consists of three periods, as displayed in figure 1. We assume that, at each period, all previous-periods actions are observable to the players who base their current decisions in that information and on their "correct" rational expectation about the behavior of all other players in the current period and subsequent period outcomes. Thus, the proactive transmission investment valuation model is characterized as a "complete- and perfect-information" game[2] and the equilibrium as "sub game perfect".

[2] A "complete- and perfect-information" game is defined as a game in which players move sequentially and, at each point in the game, all previous actions are observable to all players.

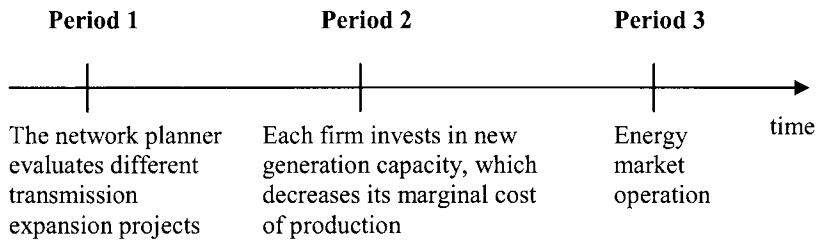

Figure 1: Three-period transmission investment valuation model

This model is static. That is, the model parameters (demand and cost functions, electric characteristics of the transmission lines, etc.) do not change over time. Accordingly, we may interpret the model as representing an investment cycle with sufficient lead time between the periods while period 3 encapsulates the average outcomes of a recurring spot energy market realization under multiple demand and supply contingencies. All the costs and benefits represented in the model are annualized.

We now explain the model backwards. The last period (period 3) represents the energy market operation. That is, in this period, we compute the equilibrium quantities and prices of electricity for given generation and transmission capacities. We model the energy market equilibrium in the topology of the transmission network through a lossless DC approximation of Kirchhoff's laws. Specifically, flows on lines are calculated using the power transfer distribution factor (PTDF) matrix, whose elements give the proportion of flow on a particular line resulting from an injection of one unit of power at any particular node and a corresponding withdrawal at an arbitrary (but fixed) slack bus. Different PTDF matrices, with corresponding state probabilities, characterize uncertainty regarding the realized network topology where the generation and transmission capacities are subject to random fluctuations, or contingencies, that are realized in period 3 prior to the production and redispatch decisions by the generation firms and the system operator. We will assume that the probabilities of all credible contingencies are public knowledge.

As in Yao et al. (2004), we model the energy market equilibrium as a subgame with two stages. In the first stage, Nature picks the state of the world (and, thus, settles the actual generation and transmission capacities as well as the shape of the demand and cost functions at each node). In the second stage, firms compete in a Nash-Cournot fashion by selecting their production quantities so as to maximize their profit while taking as given the production quantities of their rivals and the simultaneous import/export decisions of a system operator. The system operator determines impot/export quantities at each node, taking the production decisions as given, so as to maximize social welfare while satisfying the energy balance and transmission constraints. In this setup, the production decision of the generation firms and the import/export decisions by the system operator are modeled as simultaneous moves.

In the second period, each firm invests in new generation capacity, which lowers its marginal cost of production at any output level. For the sake of tractability, we assume that generators' production decisions are not constrained by physical capacity limits. Instead, we allow generators' marginal cost curves to rise smoothly so that production quantities at any node will be limited only by economic considerations and transmission constraints. In this framework, generation expansion is modeled as "stretching" the supply function so as to lower the marginal cost at any output level and thus increase the amount of economic production at any given price. Such expansion can be interpreted as an increase in generation capacity in a way that preserves the proportional heat curve or, alternatively, assuming that any new generation capacity installed will replace old, inefficient plants and, thereby, increase the overall efficiency of the portfolio of plants in producing a given amount of electricity. This continuous representation of the supply function and generation expansion serves as a proxy to actual supply functions that end with a vertical segment at the physical capacity limit. Since typically generators are operated so as not to hit their capacity limits (due to high heat rates and expansive wear on the generators), our proxy should be expected to produce realistic results.

The return from the generation capacity investments made in period 2 occurs in period 3, when such investments enable the firms to produce electricity at lower cost and sell more of it at a profit. We assume that, in making their investment decisions in period 2, generation firms are aware to the transmission expansion from period 1 and form rational expectations regarding the investments made by their competitors and the resulting expected market equilibrium in period 3. Thus, the generation investment and production decisions by the competing generation firms are modeled as a two-stage subgame-perfect Nash equilibrium.

Finally, in the first period, the network planner (or system operator as in some parts of the US), which we model as a Stackelberg leader in our three-period game, evaluates different projects to expand the transmission network while anticipating the generators' and the system operator's response in periods 2 and 3. In particular, we consider here the case where the network planner evaluates a single transmission expansion decision, but the proposed approach can be extended to more complex investment options.

Because the network planner under this paradigm anticipates the response by the generation firms, optimizing the transmission investment plan will also determine the best way of inducing generation investment so as to maximize the objective function set by the network planner (usually social welfare). Therefore, we will use the term "proactive network planner" to describe such a planning approach which results in outcomes that, although they are still inferior to the integrated-resource planning paradigm, they often result in the same investment decisions. In this model, we limit the transmission investment decisions to expanding the capacity of any one line according to some specific transmission-planning objective (the maximization of expected social welfare in this case).[3] Our model allows both the upgrades of existing transmission lines and the construction of new transmission lines. Transmission upgrades that affect the electric properties of lines will obviously alter PTDF matrices. Consequently, our model explicitly takes into consideration the changes in the PTDF matrices that are induced by alterations in either the network structure or the electric characteristics of transmission lines.

Since the energy market equilibrium will be a function of the thermal capacities of all constrained lines, the Nash equilibrium of generation capacities will also be a function of these capacity limits. The proactive network planner, then, has multiple ways of influencing this Nash equilibrium by acting as a Stackelberg leader who anticipates the equilibrium of generation capacities and induces generation firms to make more socially optimal investments.

We further assume that the generation cost functions are both increasing and convex in the amount of output produced and decreasing and convex in the generation capacity. Furthermore, as we mentioned before, we assume that the marginal cost of production at any output level decreases as the generation capacity increases. Moreover, we assume that both the generation capacity investment cost and the transmission capacity investment cost are linear in the extra-capacity added. We also assume downward-sloping, linear demand functions at each node. To further simplify things, we assume no wheeling fees.

2.2 Notation

Sets:

- N: set of all nodes.
- L: set of all transmission lines.
- C: set of all states of contingencies.

[3] "Expected social welfare" is defined as the sum of consumer surplus, producer surplus, and congestion rent that is expected before the realization of the spot market.

- N_G: set of generation nodes controlled by generation firm G
- Ψ: set of all generation firms

Decision variables:

- q_i^c: quantity generated at node i in state c.
- r_i^c: adjustment quantity into/from node i by the system operator in state c.
- g_i: expected generation capacity available at node i after implementing the decisions made in period 2.
- f_ℓ : expected thermal capacity limit of line ℓ after implementing the decisions made in period 1.

Parameters:

- g_i^0: expected generation capacity available at node i before period 2.
- f_ℓ^0: expected thermal capacity limit of line ℓ before period 1.
- g_i^c: generation capacity available at node i in state c, given g_i.
- f_ℓ^c: thermal capacity limit of line ℓ in state c, given f_ℓ.
- $P_i^c(\cdot)$: inverse demand function at node i in state c.
- $CP_i^c(q_i^c, g_i^c)$: production cost function at node i in state c.
- $CIG_i(g_i, g_i^0)$: cost of investment in generation capacity at node i to bring expected generation capacity to g_i.
- $CI_\ell(f_\ell, f_\ell^0)$: investment cost in line ℓ to bring expected transmission capacity to f_ℓ
- $\phi_{\ell,i}^{\ c}(L)$: power transfer distribution factor on line ℓ with respect to a unit injection/withdrawal at node i, in state c, when the network properties (network structure and electric characteristics of all lines) are given by the set L.

2.3 Formulation

We start by formulating the third-period problem. In the first stage of period 3, Nature determines the state of the world. In the second stage, for a given state c, generation firm G ($G \in \Psi$) solves the following profit-maximization problem:

$$\begin{aligned} &\text{Max}_{\{q_i^c,\, i\in N_G\}} \quad \pi_G^c = \sum_{i\in N_G} \left\{ P_i^c(q_i^c + r_i^c)\cdot q_i^c - CP_i^c(q_i^c, g_i^c) \right\} \\ &s.t. \qquad q_i^c \geq 0 \quad , \; i\in N_G \end{aligned} \tag{1}$$

Simultaneously with the generators' production quantity decisions, the system operator solves the following welfare maximizing redispatch problem (for the given state c):

$$\begin{aligned} &\text{Max}_{\{r_i^c,\, i\in N\}} \quad \Delta W^c = \sum_{i\in N} \left\{ \int_0^{r_i^c} P_i^c(q_i^c + x_i)\, dx_i \right\} \\ &s.t. \qquad \sum_{i\in N} r_i^c = 0 \\ &\qquad\quad -f_\ell^{\,c} \leq \sum_{i\in N} \phi_{\ell,i}{}^c(L)\cdot r_i^c \leq f_\ell^{\,c} \quad , \; \forall \ell\in L \\ &\qquad\quad q_i^{\,c} + r_i^{\,c} \geq 0 \qquad\qquad , \; \forall i\in N \end{aligned} \tag{2}$$

Given that we assume no wheeling fees, the system operator can gain social surplus, at no extra cost, by exporting some units of electricity from a cheap-generation node while importing them to other nodes until the prices at the nodes are equal, or until some transmission constraints are binding.

The previously specified model assumptions guarantee that both (1) and (2) are concave programming problems, which implies that first order necessary conditions (i.e. KKT conditions) are also sufficient. Consequently, to solve the period-3 problem (energy market equilibrium), we can just jointly solve the KKT conditions of the problems defined in (1), for all G $\in$ Ψ, and (2), which together form a linear complementarity problem (LCP) that can be easily solved with off-the-shelf software packages.

The KKT conditions for the problems defined in (1) are:

$$P_i^c(q_i^c + r_i^c) + P_i^{c\prime}(q_i^c + r_i^c) \cdot q_i^c - \frac{\partial CP_i^c(q_i^c, g_i^c)}{\partial q_i^c} + \gamma_i^c = 0 \ , \ \forall i \in N_G, G \in \Psi, c \in C \tag{3}$$

$$\gamma_i^c \cdot q_i^c = 0 \ , \ \ \forall i \in N_G, G \in \Psi, c \in C \tag{4}$$

$$q_i^c \geq 0, \quad \forall i \in N_G, G \in \Psi, c \in C \tag{5}$$

$$\gamma_i^c \geq 0, \quad \forall i \in N_G, G \in \Psi, c \in C \tag{6}$$

where γ_i^c correspond to the Lagrangian multipliers associated to the non-negativity constraints in (1).

The KKT conditions for the problem defined in (2) are:

$$P_i^c(q_i^c + r_i^c) + \alpha^c + \sum_{\ell \in L} \left(\lambda_{\ell -}^c - \lambda_{\ell +}^c\right) \cdot \phi_{\ell,i}{}^c(L) + \beta_i^c = 0 \ , \quad \forall \ i \in N, \ c \in C \tag{7}$$

$$\sum_{i \in N} r_i^c = 0, \quad \forall \ c \in C \tag{8}$$

$$-f_\ell^c \leq \sum_{i \in N} \phi_{\ell,i}{}^c(L) \cdot r_i^c \leq f_\ell^c \ , \quad \forall \ \ell \in L, c \in C \tag{9}$$

$$q_i^c + r_i^c \geq 0, \quad \forall \ i \in N, \ c \in C \tag{10}$$

$$\lambda_{\ell-}^{c} \cdot \left(f_{\ell}^{c} + \sum_{i \in N} \phi_{\ell,i}{}^{c}(L) \cdot r_{i}^{c} \right) = 0 , \quad \forall\ \ell \in L,\ c \in C \tag{11}$$

$$\lambda_{\ell+}^{c} \cdot \left(f_{\ell}^{c} - \sum_{i \in N} \phi_{\ell,i}{}^{c}(L) \cdot r_{i}^{c} \right) = 0 , \quad \forall\ \ell \in L,\ c \in C \tag{12}$$

$$\beta_{i}^{c} \cdot \left(q_{i}^{c} + r_{i}^{c} \right) = 0, \quad \forall\ i \in N,\ c \in C \tag{13}$$

$$\lambda_{\ell-}^{c} \geq 0, \quad \forall\ \ell \in L,\ c \in C \tag{14}$$

$$\lambda_{\ell+}^{c} \geq 0, \quad \forall\ \ell \in L,\ c \in C \tag{15}$$

$$\beta_{i}^{c} \geq 0, \quad \forall\ i \in N,\ c \in C \tag{16}$$

where α^c is the Lagrangian multiplier associated to the adjustment-quantities balance constraint, $\lambda_{\ell-}^{c}$ and $\lambda_{\ell+}^{c}$ are the Lagrangian multipliers associated to the transmission capacity constraints, and β_i^c are the Lagrangian multipliers associated to the non-negativity constraints in (2).

In period 2, each firm determines how much to invest in new generation capacity by maximizing the expected value of the investment (we assume risk-neutral firms) subject to (3) - (16), which represent the anticipated actions in period 3. Since the investments in new generation capacity reduce the expected marginal cost of production, the return from the investments made in period 2 occurs in period 3. Thus, in period 2, firm G ($G \in \Psi$) solves the following optimization problem:

$$\begin{array}{ll} \text{Max}_{\{g_i, i \in N_G\}} & E_c\left[\pi_G^c\right] - \sum_{i \in N_G} \left\{ CIG_i(g_i, g_i^0) \right\} \\ s.t. & (3) - (16) \end{array} \tag{17}$$

The problem defined in (17) is a Mathematical Program with Equilibrium Constraints (MPEC) problem.[4] Thus, the period-2 problem can be converted to an Equilibrium Problem with Equilibrium Constraints (EPEC), in which each firm faces (given other firms' commitments and the system operator's import/export decisions) an MPEC problem. However, this EPEC is constrained in a non-convex region and, therefore, we cannot simply write down the first order necessary conditions for each firm and aggregate them into a large problem to be solved directly. In Section 4, we solve this problem for the particular case-study network, using a sequential quadratic programming algorithm.

In the first period, the network planner evaluates different transmission expansion projects. In this period, the network planner is limited to decide which line (among both the already existing lines and some proposed new lines) should be upgraded, and what should be the transmission capacity for that line, in order to maximizes the expected social welfare subject to the equilibrium constraints representing the anticipated actions in periods 2 and 3.[5] Thus, in period 1, the proactive network planner's social-welfare-maximizing problem is:

$$\text{Max}_{\ell, f_\ell} \sum_{i \in N} \left\{ E_c \left[\int_0^{q_i^c + r_i^c} P_i^c(q)\, dq - CP_i^c(q_i^c, g_i^c) \right] - CIG_i(g_i, g_i^0) \right\} - CI_\ell(f_\ell, f_\ell^0) \tag{18}$$

$$s.t. \qquad (3)\text{-}(16)$$

and all optimality conditions of period-2 problem.

[4] For formal definitions of MPEC and EPEC problems, see (Yao et al., 2004).

[5] No attempt is made to co-optimize the network planner/system operator's transmission expansion and redispatch decisions. We assume that the transmission planning function treats the real-time redispatch function as an independent follower and anticipates its equilibrium response as if it was an independently controlled entity with no attempt to exploit possible coordination between transmission planning and real-time dispatch. One should keep in mind, however, that such coordination might be possible in a for-profit system operator enterprise such as in the UK.

We will not attempt to solve this problem, but rather use this formulation as a framework for evaluating alternative predetermined transmission expansion proposals. For that purpose, we will only focus on the benefit portion of the objective function in (18), which can be contrasted with the transmission investment cost. In our case study, we will only compare benefits, which is equivalent to assuming that all candidate transmission investments have the same cost.

3. THEORETICAL RESULTS

In the previous section, we formulated the transmission investment valuation model used by a proactive network planner (PNP). In this section, we compare, from a theoretical point of view, the valuations of transmission investment projects made by the PNP with both those made under the integrated-resources planning (IRP) paradigm and those made under the reactive network planning (RNP) paradigm. The optimal objective-function value for the IRP and the RNP plans provide upper and lower bounds for the objective function value corresponding to the optimal PNP plan. In order to facilitate the comparison, we first introduce mathematical formulations of both the IRP and the RNP transmission investment valuation models.

3.1 Integrated-Resources Planner (IRP) Model

In this model, we assume that the IRP jointly plans generation and transmission expansions although the energy market operation is still decentralized. The IRP model consists of two periods: A and B. The last period (period B) corresponds to the energy market operation and it is modeled identically to the third period of the model described in the previous section. Thus, it is defined by (1) and (2) and its optimal solution is characterized by the KKT conditions stated in (3) - (16). In the first period (period A), the IRP jointly selects the generation investment levels and the social-welfare-maximizing location and magnitude for transmission expansion. Hence, in period A, the IRP solves the following social-welfare-maximizing problem:

$$\text{Max}_{\{g_i\},\ell,f_\ell} \sum_{i\in N}\left\{E_c\left[\int_0^{q_i^c+r_i^c} P_i^c(q)\,dq - CP_i^c(q_i^c, g_i^c)\right] - CIG_i(g_i, g_i^0)\right\} - CI_\ell(f_\ell, f_\ell^0) \tag{19}$$

$$\text{s.t.} \qquad (3)\text{-}(16)$$

3.2 Reactive Network planner (RNP) Model

In this model, the network planner plans the social-welfare-maximizing location and magnitude for transmission upgrades assuming no change in the current generation stock, but accounting for the effect of the transmission upgrades on the energy market. This model has the same structure as the PNP model with the exception that the objective function used to evaluate alternative transmission upgrades in period 1 assumes that the generation stock upon which the energy market equilibrium is based is the current one. Thus, the third period equilibrium is again characterized by (3)-(16) with generation cost functions set based on the current generation stock. In other words, the RNP does not take into consideration the potential effect that its decisions could have on generation investment decisions in period 2 and assumes that generation capacities do not change. Thus, the RNP solves the following social-welfare-maximizing problem in the first period:

$$\begin{aligned} &\text{Max}_{\ell,f_\ell} \sum_{i\in N}\left\{E_c\left[\int_0^{q_i^c+r_i^c} P_i^c(q)\,dq - CP_i^c(q_i^c, g_i^c)\right] - CIG_i(g_i, g_i^0)\right\} - CI_\ell(f_\ell, f_\ell^0) \\ &\text{s.t.} \qquad (3)\text{-}(16) \\ &\qquad\quad g_i = g_i^0 \quad , \quad \forall i \in N \end{aligned} \tag{20}$$

However, in evaluating the outcome of the RNP investment policy, we are considering the generation-firms' response to the transmission investment and its implication on the spot market equilibrium.

3.3 Transmission Investment Valuation Models Comparison

Now, we compare the optimal transmission investment decisions made for a PNP with corresponding optimal decisions of an IRP and a RNP.

Proposition 1: The optimal expected social welfare obtained from the integrated-resources planner model is never smaller than the optimal expected social welfare obtained from the proactive network planner model.

Proof: By comparing (18) and (19), we can observe that solving (18) is equivalent to solving (19) while imposing the extra constraint that generation-firms' capacities solve (17). Thus, the feasible set of (18) is a subset of the feasible set of (19). Consequently, since both (18) and (19) maximize the same objective function, the optimal solution of (18) must be in the feasible set of (19), which implies that the optimal solution to (19) cannot be worse (in terms of expected social welfare) than the optimal solution of (18).■

Proposition 2: The optimal expected social welfare obtained from the proactive network planner model is never smaller than the optimal expected social welfare obtained from the reactive network planner model.

Proof: By comparing (18) and (20), we observe that, if we eliminated the last constraint of each problem (second-period problem conditions), then both problems would be identical. Thus, there exists a correspondence from generation capacities space to transmission capacities space, $f^*(g)$, that characterizes the "unconstrained" optimal investment decisions of both the PNP and the RNP. Since the second periods of both models are identically modeled, there also exists a correspondence from transmission capacities space to generation capacities space, $g^*(f)$, that characterizes the generation-firms' optimal response to transmission investments under both the PNP and the RNP models. The optimal solution of the PNP model is at the intersection of these two correspondences. That is, the transmission capacity chosen by the PNP, f^*_{PNP}, is such that $f^*(g^*(f^*_{PNP})) = f^*_{PNP}$. On the other hand, the transmission capacity chosen by the RNP, f^*_{RNP}, is on the correspondence $f^*(g)$, at the currently installed generation capacities (i.e., $f^*_{RNP} = f^*(g^0)$). Thus, the optimal solution of the second period of the RNP model is on the correspondence $g^*(f)$, at transmission capacities f^*_{RNP}. Since the correspondence $g^*(f)$ characterizes the optimality conditions of the period-2 problem in the PNP model, any pair $(g^*(f), f)$ represents a feasible solution of the PNP model. Consequently, the optimal solution of the RNP model, $(g^*(f^*_{RNP}), f^*_{RNP})$, is a feasible solution of the PNP model. Therefore, the optimal solution of (18) cannot be worse (in terms of expected social welfare) than the optimal solution of (20).■

Note that the previous two propositions are also valid under a different transmission-planning objective (other than expected social welfare). Consequently, we can generalize the previous propositions as in the following statement: "Under any transmission-planning objective, the optimal value obtained from the proactive network planner model is both never larger (better) than the optimal value obtained from the integrated-resources planner model and never smaller (worse) than the optimal value obtained from the reactive network planner model".

While proposition 2 states that a RNP cannot do better (in terms of expected social welfare) than a PNP, the sign of the inefficiency is not evident. That is, without adding more structure to the problem, it is not evident whether the network planner underinvests or overinvests in transmission under the RNP model, relative to the PNP investment levels. To establish such comparative static results, we need a more structured characterization of the transmission investment models solutions, which requires some extra assumptions in the transmission investment models. In particular, we assume that there exist some continuous and differentiable functions that characterize the transmission investment models equilibria. This assumption is valid for small changes in transmission and generation capacities. Unfortunately, generation and transmission investments tend to be lumpy, which means that most upgrades produce large changes in generation and transmission capacities. However, the only purpose of our continuity and differentiability assumptions is to illustrate, in a simple way, that it is possible to use our 3-period transmission investment model to derive some sufficient conditions under which we can guarantee the sign of the inefficiency of the RNP model relative to the PNP model.

The optimal solution to the period-3 problem is a function of both the capacities of generators and the capacities of lines.[6] Accordingly, the Nash equilibrium of generation capacities will be a function of the thermal capacities of all constrained lines. Consequently, if the cardinality of N and L are n and m respectively, and f is the vector of all line expected thermal capacities (i.e., $f = [\, f_{\ell 1}, \ldots, f_{\ell m}]^{\mathrm{T}}$), then we can define $g_i{*}(f)$ as the period-2 Nash-equilibrium expected capacity of the generator located at node i ($i \in N$), $g{*}(f)$ as the vector of all period-2 Nash-equilibrium expected generation capacities (i.e., $g{*}(f) = [g_1{*}(f), \ldots, g_n{*}(f)]^{\mathrm{T}}$), $q_i^c{*}(g{*}(f), f)$ as the optimal quantity generated at node i in state c during period 3, and $r_i^c{*}(g{*}(f), f)$ as the optimal adjustment quantity into/from node i by the system operator in state c during period 3. As we mentioned before, we assume that $g{*}$, $q_i^c{*}$ and $r_i^c{*}$ are all continuous and differentiable in all variables.[7]

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[6] To be rigorous, we should say that the period-3 problem solution is also a function of both the network structure and the electric characteristics of all transmission lines.

[7] In our model, $q_i^c{*}$ and $r_i^c{*}$ are continuous and differentiable in $g_j{*}$ ($\forall\, j \in N$) because we assumed no upper limit in the generated quantities. To justify the continuity and differentiability with respect to f_ℓ ($\forall\, \ell \in L$), we can argue that it is possible to relax the transmission capacity constraints while introducing some adequate penalty functions into the objective function of the problem defined in (2).

Assuming that q_i^c* and r_i^c* are given continuous and differentiable functions, we can re-formulate (17) as the following unconstrained problem:

$$\text{Max}_{\{g_i, i\in N_G\}} \sum_{i\in N_G}\left\{E_c\left[P_i^c(q_i^c*+r_i^c*)\cdot q_i^c* - CP_i^c(q_i^c*,g_i^c)\right] - CIG_i(g_i,g_i^0)\right\} \qquad (21)$$

Then, for given functions q_i^c* and r_i^c*, we can write the KKT conditions for the problems defined in (21), $\forall\, i \in N_G$, as:

$$\begin{aligned}&\sum_{j\in N_G}\left\{E_c\left[P_j^c(q_j^c*+r_j^c*)\cdot\frac{\partial q_j^c*}{\partial g_i} + P_j^{c\prime}(q_j^c*+r_j^c*)\cdot\frac{\partial\left(q_j^c*+r_j^c*\right)}{\partial g_i}\cdot q_j^c*\right.\right.\\ &\left.\left.-\frac{\partial CP_j^c(q_j^c*,g_j^c)}{\partial q_j^c*}\cdot\frac{\partial q_j^c*}{\partial g_i}\right]\right\} - E_c\left[\frac{\partial CP_i^c(q_i^c*,g_i^c)}{\partial g_i}\right] - \frac{\partial CIG_i(g_i,g_i^0)}{\partial g_i} = 0\end{aligned} \qquad (22)$$

Equations (22) indicate that the value of additional generation capacity to a firm depends on the capacity levels of all the other generators and the transmission capacities of all lines in the network. Moreover, (22) means that, under the existence of local market power, generation firms will not invest so as to just equate the expected reduction in the marginal cost of production and the marginal investment cost (i.e., the last two terms in (22)). On the contrary, firms will invest in generation capacity taking into account the effect of their investments on the energy market equilibrium.

Assuming $g*$, q_i^c* and r_i^c* are given functions, we can also re-formulate (18) as the following unconstrained problem:

$$\text{Max}_{\ell, f_\ell} \sum_{i\in N}\left\{E_c\left[\int_0^{q_i^c*+r_i^c*} P_i^c(q)\,dq - CP_i^c(q_i^c*, g_i^c*)\right] - CIG_i(g_i*, g_i^0)\right\} - CI_\ell(f_\ell, f_\ell^0) \qquad (23)$$

As indicated earlier, we do not attempt to solve this problem algorithmically, but use it as a framework for evaluating alternative investment options and compare the theoretical outcome of the three planning paradigms considered in this paper.

For given functions g^*, $q_i^{c}*$ and $r_i^{c}*$, we can write the KKT conditions for the problem defined in (23), for some optimal $\ell \in L$, as:

$$\sum_{i \in N}\left\{ E_c\left[P_i^c(q_i^c * + r_i^c *)\cdot\left(\sum_{j\in N}\left(\frac{\partial q_i^c *}{\partial g_j *}\cdot\frac{\partial g_j *}{\partial f_\ell}\right)+\frac{\partial q_i^c *}{\partial f_\ell}+\sum_{j\in N}\left(\frac{\partial r_i^c *}{\partial g_j *}\cdot\frac{\partial g_j *}{\partial f_\ell}\right)+\frac{\partial r_i^c *}{\partial f_\ell}\right)-\right.\right.$$

$$\left.-\frac{\partial CP_i^c(q_i^c *, g_i^c *)}{\partial q_i^c *}\cdot\left(\sum_{j\in N}\left(\frac{\partial q_i^c *}{\partial g_j *}\cdot\frac{\partial g_j *}{\partial f_\ell}\right)+\frac{\partial q_i^c *}{\partial f_\ell}\right)-\frac{\partial CP_i^c(q_i^c *, g_i^c *)}{\partial g_i *}\cdot\frac{\partial g_i *}{\partial f_\ell}\right]- \tag{24}$$

$$\left.-\frac{\partial CIG_i(g_i *, g_i^0)}{\partial g_i *}\cdot\frac{\partial g_i *}{\partial f_\ell}\right\}-\frac{\partial CI_\ell(f_\ell, f_\ell^0)}{\partial f_\ell}=0$$

Now, we are able to establish some sufficient conditions under which we can guarantee the sign of the RNP's inefficiency in transmission investments as compared with the investment levels under the PNP model.

Proposition 3: Suppose that the gain in expected welfare of an incremental unit of generation capacity is greater (smaller) than the marginal investment cost for those generation firms whose generation capacities are strategic complements (substitutes) to the transmission capacity at the optimal location of the transmission upgrade. Furthermore, assume that the optimal location of the transmission upgrade is the same under both the RNP model and the PNP model. Then, the reactive network planner will underinvest in transmission capacity as compared to the proactive network planner.

Proof: Let $q_i^{c}*$ and $r_i^{c}*$ ($\forall\ i \in N,\ c \in C$) define an optimal solution for the third period of the RNP model. Then, for given functions $q_i^{c}*$ and $r_i^{c}*$ ($\forall\ i \in N,\ c \in C$), any optimal solution to the first-period optimization of the RNP model must satisfy the following first order optimality condition (for some optimal $\ell \in L$):

$$\sum_{i\in N}\left(\partial E_c\left[\int_0^{q_i^{c*}+r_i^{c*}} P_i^c(q)\,dq - CP_i^c(q_i^{c*}, g_i^c)\right]\Big/\partial f_\ell\right) - \frac{\partial CI_\ell(f_\ell, f_\ell^0)}{\partial f_\ell} = 0$$

Then, we can re-write (24), which corresponds to the first order optimality condition of the period-1 problem of the PNP model, as follows (assuming that the optimal location of the next transmission upgrade, ℓ ($\ell \in L$), is the same under both the RNP model and the PNP model):

$$\overbrace{\sum_{i\in N}\left(\partial E_c\left[\int_0^{q_i^{c*}+r_i^{c*}} P_i^c(q)\,dq - CP_i^c(q_i^{c*}, g_i^c)\right]\Big/\partial f_\ell\right) - \frac{\partial CI_\ell(f_\ell, f_\ell^0)}{\partial f_\ell}}^{\text{Reactive network planner}} + \underbrace{\sum_{j\in N}\left\{\sum_{i\in N}\left(\partial E_c\left[\int_0^{q_i^{c*}+r_i^{c*}} P_i^c(q)\,dq - CP_i^c(q_i^{c*}, g_i^c)\right]\Big/\partial g_j^* - \frac{\partial CIG_j(g_i^*, g_i^0)}{\partial g_j^*}\right)\cdot\frac{\partial g_j^*}{\partial f_\ell}\right\}}_{\text{Period-2 NE enhancement effect by the PNP}} = 0 \tag{25}$$

The previous optimality condition undoubtedly shows that the proactive network planner alters its actions (as compared to an RNP) in order to recapture some of the social welfare lost due to the socially inefficient generation capacity investments.

Using (25), it follows directly from the proposition assumptions that the "period-2 Nash-equilibrium enhancement effect" made by the PNP is positive, which implies that the RNP will underinvest in transmission capacity as compared to the PNP (assuming that the optimal location of the next transmission upgrade is the same under both the RNP model and the PNP model).■

Equation (25) clearly reflects how the proactive network planner differs from its reactive counterpart (i.e., from a network planner that ignores the dependency of the equilibrium of generation capacities on the transmission capacities). In addition to the welfare gained directly by adding transmission capacity, which by definition corresponds to the sum of all the shadow prices of the transmission constraints, the PNP also considers how its investment can induce a more socially efficient Nash equilibrium of expected generation capacities. In fact, it includes a "period-2 Nash-equilibrium enhancement effect" into the social value of transmission capacity. Although the sign of this effect is not evident in general, proposition-3 assumptions guarantee a positive sign.

The three previous propositions deal with the transmission investment decisions made under the different paradigms. It is also interesting to analyze what can be said about the generation investment decisions made under the corresponding models. The next proposition sets up some sufficient conditions under which we can guarantee that a generation firm will underinvest under either the PNP or the RNP paradigm as compared to investment levels implied by the IRP.

Proposition 4: Under either the PNP model or the RNP model, if a firm owning only the generation capacity at one specific node invests such that both its expected marginal revenue is smaller than the expected marginal gross benefit of the consumers at that node and the expected welfare at any other node is non-decreasing in its generation capacity, then the generation firm will underinvest relative to the IRP-model investment levels.

Proof: Let q_i^c* and r_i^c* define the market equilibrium of period B in the IRP model (they also define the market equilibrium in the third period of both the PNP model and RNP model). Then, given q_i^c* and r_i^c*, any optimal solution of period A of the IRP model must satisfy the following first order optimality condition:

$$E_c\left[\sum_{j\in N}\left\{P_j^c(q_j^{c*}+r_j^{c*})\cdot\frac{\partial(q_j^{c*}+r_j^{c*})}{\partial g_i}-\frac{\partial CP_j^c(q_j^{c*},g_j^c)}{\partial q_j^{c*}}\cdot\frac{\partial q_j^{c*}}{\partial g_i}\right\}\right]$$
$$-\ E_c\left[\frac{\partial CP_i^c(q_i^{c*},g_i^c)}{\partial g_i}\right]-\frac{\partial CIG_i(g_i,g_i^0)}{\partial g_i}\ =0 \tag{26}$$

On the other hand, (22) represents an optimality condition for the generation-firms' investment problem under both the PNP model and the RNP model. By comparing (22) and (26) in the case of a firm owning only the generation capacity at node *i*, it is clear that it suffices to prove that:

$$E_c\left[P_i^c(q_i^{c*}+r_i^{c*})\cdot\frac{\partial q_i^{c*}}{\partial g_i}+P_i^{c}{}'(q_i^{c*}+r_i^{c*})\cdot\frac{\partial\left(q_i^{c*}+r_i^{c*}\right)}{\partial g_i}\cdot q_i^{c*}\right]$$
$$<\ E_c\left[P_i^c(q_i^{c*}+r_i^{c*})\cdot\frac{\partial(q_i^{c*}+r_i^{c*})}{\partial g_i}\right]+\sum_{\substack{j\in N\\ j\neq i}}\left\{E_c\left[\partial\left(\int_0^{q_j^{c*}+r_j^{c*}}P_j^c(q)\,dq-CP_j^c(q_j^{c*},g_j^c)\right)\Big/\partial g_i\right]\right\} \tag{27}$$

Assume that the expected marginal revenue of the considered firm (i.e., the firm owning the generation capacity at node *i*) is smaller than the expected marginal gross benefit of the consumers at that node. Then,

$$E_c\left[P_i^c(q_i^{c*}+r_i^{c*})\cdot\frac{\partial q_i^{c*}}{\partial g_i}+P_i^{c}{}'(q_i^{c*}+r_i^{c*})\cdot\frac{\partial\left(q_i^{c*}+r_i^{c*}\right)}{\partial g_i}\cdot q_i^{c*}\right]$$
$$<\ E_c\left[P_i^c(q_i^{c*}+r_i^{c*})\cdot\frac{\partial(q_i^{c*}+r_i^{c*})}{\partial g_i}\right] \tag{28}$$

Moreover, assume that the expected welfare at any node other than *i* is non-decreasing in the generation capacity at node *i*. That is,

$$E_c\left[\partial\left(\int_0^{q_j^{c*}+r_j^{c*}} P_j^c(q)\,dq - CP_j^c(q_j^{c*}, g_j^c)\right)\Bigg/\partial g_i\right] \geq 0 \quad, \forall\, j \in N,\, j \neq i. \tag{29}$$

By using (28) and (29) we can verify the validity of (27). ■

4. CASE STUDY

We illustrate the theoretical results derived in the previous section using a stylized version of the 30-bus/3-zone network displayed in figure 2, which was developed at Cornell University for experimental economic studies of electricity markets (http://www.pserc.cornell.edu/powerweb). There are six generation firms in the market (each one owning the generation capacity at a single node). Nodes 1, 2, 13, 22, 23, and 27 are the generation nodes. There are 39 transmission lines. The electric characteristics of the transmission lines are listed in table 7 in the appendix.

The uncertainty associated with the energy market operation is classified into seven independent contingent states (see Table 1). Six of them have small independent probabilities of occurrence (two involve demand uncertainty, two involve network uncertainty and the other two involve generation uncertainty). Table 2 shows the nodal information in the normal state.

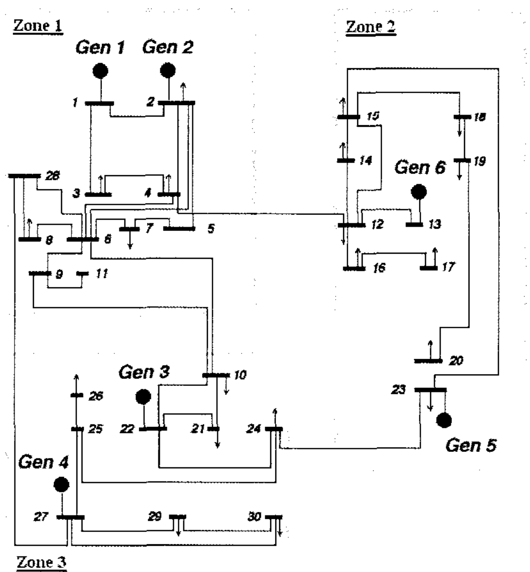

Figure 2: 30-bus Cornell network.

Table 1: States of contingencies associated with the energy market operation

State	Probability	Type of uncertainty and description
1	0.82	Normal state: Data set as in table 2
2	0.03	Demand uncertainty: All demands increase by 10%
3	0.03	Demand uncertainty: All demands decrease by 10%
4	0.03	Network uncertainty: Line 15-23 goes down
5	0.03	Network uncertainty: Line 23-24 goes down
6	0.03	Generation uncertainty: Generator at node 1 goes down
7	0.03	Generation uncertainty: Generator at node 13 goes down

Table 2: Nodal information used in the 30-bus Cornell network in the normal state

Data type (units)	Information	Nodes where apply
Inverse demand function (\$/MWh)	$P_i(q) = 50 - q$	1, 2, 5, 6, 9, 11, 13, 16, 18, 20, 21, 22, 25, 26, 27, 28, and 29.
Inverse demand function (\$/MWh)	$P_i(q) = 55 - q$	4, 8, 10, 12, 14, 15, 17, 19, 24, and 30.
Inverse demand function (\$/MWh)	$P_i(q) = 60 - q$	3, 7, and 23.
Generation cost function (\$/MWh)	$CP_i(q_i, g_i) = (0.25 \cdot q_i^{\,2} + 20 \cdot q_i) \cdot (g_i^0 / g_i)$	1, 2, 13, 22, 23, and 27 (all generation nodes).

We assume the same production cost function, $CP_i^c(\cdot)$, for all generators and all contingencies. Note that $CP_i^c(\cdot)$ is increasing in q_i^c, but it is decreasing in g_i^c. Moreover, recall that we have assumed that generators have unbounded capacity (i.e., they never reach the upper generation capacity limit). Thus, the only important effect of investing in generation capacity is lowering the production cost. Moreover, we assume that all generation firms have the same investment cost function, given by $CIG_i(g_i, g_i^0) = 8 \cdot (g_i - g_i^0)$, in dollars. The before-period-2 expected generation capacity is assumed the same for all generation nodes and equal to 60 MW (i.e., $g_i^0 = 60$ MW $\forall\ i \in \{1,2,13,22,23,27\}$). For our purposes, the choice of the parameter g_i^0 is not important because the focus of this paper is not generation adequacy. Instead, what we are really interested in is the ratio (g_i^0/g_i) since we focus on the cost of generating power and the effect that both generation and transmission investments have over that cost.

As mentioned before, the KKT conditions of the period-3 problem of the PNP model constitute a Linear Complementarity Problem (LCP). We solve it, for each contingent state, by minimizing the complementarity conditions subject to the linear equality constraints and the non-negativity constraints.[8] The period-2 problem of the PNP model is an Equilibrium Problem with Equilibrium Constraints (EPEC), in which each firm faces a Mathematical Program subject to Equilibrium Constraints (MPEC).[9] We attempt to solve for an equilibrium, if at least one exists, by iterative deletion of dominated strategies. That is, we sequentially solve each firm's profit-maximization problem using as data the optimal values from previously solved problems. Thus, starting from a feasible solution, we solve for g_1 using $g_{(-1)}$ as data in the first firm's optimization problem (where $g_{(-1)}$ means all firms' generation capacities except for firm 1's), then solve for g_2 using $g_{(-2)}$ as data, and so on. We solve each firm's profit-maximization problem using sequential quadratic programming algorithms implemented in MATLAB®.

We test our model from a set of different starting points and using different generation-firms' optimization order. All these trials gave us the same results. For the PNP model, the optimal levels of generation capacity under absence of transmission investments are $(g_1^*, g_2^*, g_3^*, g_4^*, g_5^*, g_6^*) = (100.92, 103.72, 101.15, 95.94, 77.07, 87.69)$, in MW. Table 3 lists the corresponding generation quantities (q_i), adjustment quantities (r_i) and nodal prices (P_i) in the normal state. Figure 3 illustrates these results in the Cornell network. In figure 3, thick lines represent the transmission lines reaching their thermal capacities (in the indicated direction) and circles are located in the nodes with the highest prices (above $48/MWh).

---

[8] Recall that any LCP can be written as the problem of finding a vector $x \in \Re^n$ such that $x = q + M \cdot y$, $x^T \cdot y = 0$, $x \geq 0$, and $y \geq 0$, where $M \in \Re^{n \times n}$, $q \in \Re^n$, and $y \in \Re^n$. Thus, we can solve it by minimizing $x^T \cdot y$ subject to $x = q + M \cdot y$, $x \geq 0$, and $y \geq 0$. If the previous problem has an optimal solution where the objective function is zero, then that solution also solves the corresponding LCP. Greater details about the methodology used for solving LCPs are given in (Hobbs, 2001).

[9] See (Yao et al., 2004) for definitions of both EPEC and MPEC.

Table 3: Generation quantities, adjustment quantities, and nodal prices in the normal state, in the PNP model, under absence of transmission investments

Node	q_i (MWh)	r_i (MWh)	P_i ($/MWh)
1	27.397	-24.827	47.43
2	27.808	-25.230	47.42
3	0	12.544	47.46
4	0	7.539	47.46
5	0	2.600	47.40
6	0	2.624	47.38
7	0	12.614	47.39
8	0	7.630	47.37
9	0	2.838	47.16
10	0	7.950	47.05
11	0	2.838	47.16
12	0	6.932	48.07
13	24.706	-21.547	46.84
14	0	6.799	48.20
15	0	6.612	48.39
16	0	1.932	48.07
17	0	6.932	48.07
18	0	1.022	48.98
19	0	6.022	48.98
20	0	1.022	48.98
21	0	3.033	46.97
22	27.055	-23.997	46.94
23	21.724	-7.474	45.75
24	0	8.474	46.53
25	0	3.152	46.85
26	0	3.152	46.85
27	26.310	-23.354	47.04
28	0	2.663	47.34
29	0	2.500	47.50
30	0	7.007	48.00

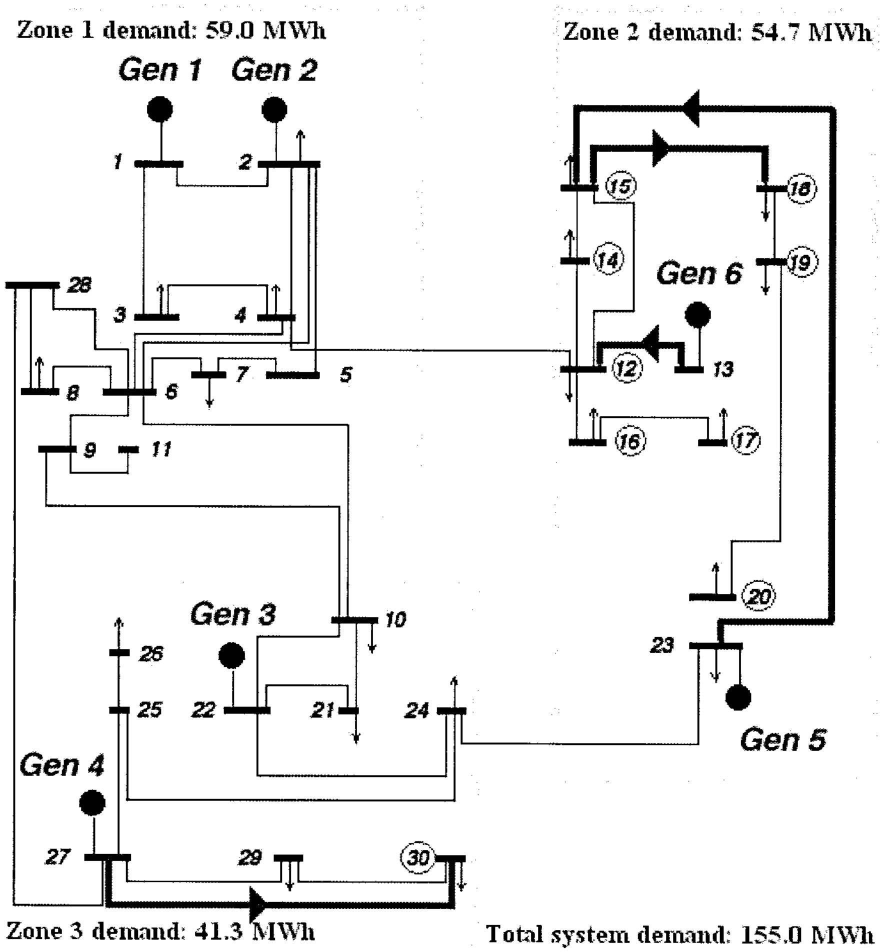

Figure 3: Results of the PNP model in the normal state, in the absence of transmission investment, for the 30-bus Cornell network.

To evaluate the period-1 objective-function value corresponding to a transmission line expansion in the PNP model, we solve a period-2 problem that considers the new network data to solve the energy market equilibrium at period 3. We then compare the values obtained for alternative line expansions and identify the one producing the highest expected social welfare gain. For simplicity, we do not consider transmission investment costs. Thus, the values obtained establish upper limits on the economic investment in each line expansion (not accounting for reliability considerations).

The four congested lines in the normal state, in absence of transmission investment, are obvious candidates for the single-line upgrade. We tested the PNP decision by comparing the results of independently adding 100 MVA of capacity to each one of these four lines and to four new lines.[10] The results are summarized in table 4. In assessing the economic impacts of the alternative line expansions, we compare social-welfare implications along with the impact on market power (measured by an average Lerner index[11]), producer and consumer surplus as well as congestion rents. In table 4, "Avg. L" corresponds to the expected Lerner index averaged over all generation firms, "P.S." is the expected producer surplus of the system, "C.S." is the expected consumer surplus of the system, "C.R." represents the expected congestion rents over the entire system, "W" is the expected social welfare of the system, and "g*" corresponds to the vector of all Nash-equilibrium expected generation capacities.

[10] For simplicity, in the case of upgrading an existing line, we assume that the upgrade does not alter the electric characteristics, but only the thermal capacity of the line (for instance, this would be the case if, for the expanded line, we replaced all the wires by "low sag wires" while using the same existing high-voltage towers). On the other hand, in the case of building a line at a new location, we consider that the PTDF matrices change according to both the new network structure and the electric characteristics of the new line. For all new-line expansion projects, we evaluate the impact of the construction of a transmission line with thermal capacity equal to 100 MVA, resistance equal to 0.01 p.u., and reactance equal to 0.04 p.u.

[11] The Lerner Index is defined as the fractional price markup
i.e. (Price – Marginal cost) /Price

Table 4: Assessment of single transmission expansions under the PNP model

Expansion Type	Avg.L	P.S. ($/h)	C.S. ($/h)	C.R. ($/h)	W ($/h)	g^* (MW)
No expansion	0.552	2975.2	574.7	68.4	3618.3	[100.92; 103.72; 101.15; 95.94; 77.07; 87.69]
100 MVA on line 12-13	0.561	3015.7	591.3	39.9	3646.9	[100.62; 103.40; 100.93; 98.50; 78.56; 97.99]
100 MVA on line 15-18	0.556	2957.0	576.5	82.6	3616.1	[101.35; 104.09; 101.01; 94.38; 79.28; 92.71]]
100 MVA on line 15-23	0.571	3049.9	602.2	26.4	3678.5	[100.01; 102.80; 102.90; 102.37; 101.45; 85.06]
100 MVA on line 27-30	0.555	2986.1	581.1	58.2	3625.4	[101.10; 103.89; 101.40; 101.46; 77.68; 86.30]
100 MVA on new line 2-18	0.563	3049.0	579.9	36.6	3665.5	[100.72; 103.45; 103.09; 103.04; 76.97; 95.29]
100 MVA on new line 18-27	0.569	3052.8	588.5	37.5	3678.8	[101.01; 103.80; 102.41; 103.57; 84.36; 96.12]
100 MVA on new line 20-22	**0.561**	**3089.7**	**583.5**	**12.3**	**3685.5**	**[101.13; 103.93; 103.93; 102.04; 84.31; 82.82]**
100 MVA on new line 13-20	0.566	3041.8	592.8	31.4	3666.0	[101.12; 103.89; 101.15; 100.96; 80.15; 99.67]

From table 4, it is evident that the highest valued (in terms of expected social welfare) single transmission line expansion is to build a new line connecting nodes 20 and 22. Moreover, it is interesting to observe that some expansion projects (as adding 100 MVA on line 15-18) can decrease social welfare.

Now, we are interested in comparing the PNP "best expansion" with that obtained under the RNP paradigm for the same system conditions. We tested the RNP decision by comparing the results of independently adding 100 MVA of capacity to each one of the same (existing and new) eight lines as before. The results are summarized in table 5, where we use the notation $\bar{x}$ to represent the value of x as seen by the RNP.

Table 5: Assessment of single transmission expansions under the RNP model

Expansion Type	$\overline{\text{Avg. L}}$	$\overline{\text{P.S.}}$ (\$/h)	$\overline{\text{C.S.}}$ (\$/h)	$\overline{\text{C.R.}}$ (\$/h)	$\overline{\text{W}}$ (\$/h)
No expansion	0.395	2732.4	387.9	9.1	3129.4
100 MVA on line 12-13	0.395	2732.4	388.3	8.9	3129.6
100 MVA on line 15-18	0.395	2732.1	388.3	8.9	3129.3
100 MVA on line 15-23	0.395	2732.5	388.2	8.8	3129.5
100 MVA on line 27-30	0.395	2732.4	387.9	9.1	3129.4
100 MVA on new line 2-18	0.396	2750.4	386.8	0.5	3137.7
100 MVA on new line 18-27	**0.396**	**2751.0**	**386.8**	**0.2**	**3138.0**
100 MVA on new line 20-22	0.396	2750.7	386.8	0.3	3137.8
100 MVA on new line 13-20	0.395	2742.6	387.2	4.3	3134.1

From table 5, it is clear that the social-welfare-maximizing transmission expansion for the RNP is, in this case, to build a new transmission line connecting nodes 18 and 27. In evaluating the "true outcome" corresponding to the RNP best choice, we do take into consideration the generation investment response to that "suboptimal" choice and the subsequent energy market equilibrium, which result in Avg. L = 0.569, P.S. = \$3,052.8 /h, C.S. = \$588.5 /h, C.R. = \$ 37.5 /h, W = \$ 3,678.8 /h, and g^* = (101.01, 103.80, 102.41, 103.57, 84.36, 96.12) in MW. By comparing table 4 and table 5, it is evident that the optimal investment decision under the PNP paradigm differs from the optimal investment decision corresponding to the RNP. Specifically, the PNP considers not only the welfare gained directly by adding transmission capacity (on which the RNP bases its valuations), but also the way in which its investment induces a more socially efficient Nash equilibrium of expected generation capacities.

Finally, it is interesting to compare the results obtained with the PNP model and those obtained with an hypothetical IRP. We tested the IRP decisions by comparing the results of independently adding 100 MVA of capacity to each one of the same eight lines as before. The results are summarized in table 6.

Table 6: Assessment of single transmission expansions under the IRP model

Expansion Type	Avg.L	P.S. ($/h)	C.S. ($/h)	C.R. ($/h)	W ($/h)	g^* (MW)
No expansion	0.549	2979.5	571.1	68.5	3619.0	[100.56; 100.06; 99.67; 96.24; 77.12; 87.61]
100 MVA on line 12-13	0.564	3009.7	596.4	44.3	3650.4	[101.17; 103.90; 97.61; 97.68; 85.15; 97.87]
100 MVA on line 15-18	0.554	2969.9	578.6	70.9	3619.4	[103.00; 107.98; 95.63; 93.94; 83.92; 85.28]
100 MVA on line 15-23	0.568	3053.1	597.0	30.1	3680.2	[98.12; 100.87; 101.22; 101.07; 99.93; 87.20]
100 MVA on line 27-30	0.555	2989.4	582.2	55.9	3627.5	[102.02; 102.66; 100.64; 100.67; 80.48; 84.04]
100 MVA on new line 2-18	0.547	3096.7	565.0	8.7	3670.4	[96.09; 102.56; 95.92; 102.86; 76.83; 81.07]
100 MVA on new line 18-27	0.567	3055.8	585.6	38.2	3679.6	[100.10; 102.69; 101.13; 102.08; 84.72; 96.08]
100 MVA on new line 20-22	**0.556**	**3094.9**	**576.5**	**15.7**	**3687.1**	**[96.51; 102.19; 101.22; 99.57; 84.78; 84.16]**
100 MVA on new line 13-20	0.561	3045.1	588.0	34.9	3668.0	[102.04; 98.35; 96.17; 96.84; 86.21; 96.89]

From table 6, it is clear that the social-welfare-maximizing transmission expansion for the IRP is, in this case, to build a new line connecting nodes 20 and 22 (the same decision as in the PNP model). By comparing table 4 and table 6, we observe that, although the IRP makes the same transmission investment decision as the PNP, the IRP is able to increase the expected social welfare by choosing generation capacities that are more socially efficient than those chosen by the generation firms in the PNP model. However, the gain in social welfare of moving from the PNP model to the IRP model is very small (less than $2/h).

5. CONCLUSIONS

In this paper, we evaluated the social welfare implications of transmission investments based on equilibrium models characterizing the competitive interaction among generation firms whose decisions in generation capacity investments and production are affected by both the transmission investments and the congestion management protocols of the transmission network planner. In particular, we proposed a three-period model for studying how the exercise of local market power by generation firms affects the equilibrium between the generation and the transmission investments and, in this way, the valuation of different transmission expansion projects. We showed that, although a PNP cannot do better (in terms of expected social welfare) than an IRP, it can recoup some of the lost welfare by identifying transmission investment options that are ex-post optimal given the strategic investment response by generation companies. We also proved that a RNP cannot do better (in terms of expected social welfare) than the PNP. Moreover, we illustrated through a numerical example that the valuations of transmission investments under the RNP paradigm can result in the selection of transmission expansion options that are inferior to those selected based on the PNP valuation, given the generation investment response to such expansions. Indeed, the PNP valuation methodology can identify more socially efficient expansion options than the RNP because it takes into consideration not only the welfare gained directly by adding transmission capacity, but also the way in which its investment alters the Nash equilibria of expected generation capacities.

While the PNP paradigm is still inferior to IRP, which co-optimizes transmission and generation expansion, the reality is that IRP is no longer a relevant methodology in a system where generators are privately owned and investment decisions in generation are not centrally coordinated. On the other hand, the PNP paradigm, which at least in our example comes close to the IRP outcome, can be readily implemented as part of a transmission economic assessment methodology employed by system operators.

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APPENDIX

The network data used in our case study are provided here. Table 7 lists the electric characteristics of the 39 transmission lines of the Cornell network.

Table 7: Electric characteristics of the transmission lines of the 30-bus network

Line #	From node #	To node #	Resistance (p.u.)	Reactance (p.u.)	f_ℓ^0 (MVA)
1	1	2	0.02	0.06	130
2	1	3	0.05	0.19	130
3	2	4	0.06	0.17	65
4	3	4	0.01	0.04	130
5	2	5	0.05	0.20	130
6	2	6	0.06	0.18	65
7	4	6	0.01	0.04	90
8	5	7	0.05	0.12	70
9	6	7	0.03	0.08	130
10	6	8	0.01	0.04	32
11	6	9	0.00	0.21	65
12	6	10	0.00	0.56	32
13	9	11	0.00	0.21	65
14	9	10	0.00	0.11	65
15	4	12	0.00	0.26	65
16	12	13	0.00	0.14	65
17	12	14	0.12	0.26	32
18	12	15	0.07	0.13	32
19	12	16	0.09	0.20	32
20	14	15	0.22	0.20	16
21	16	17	0.08	0.19	16
22	15	18	0.11	0.22	16
23	18	19	0.06	0.13	16
24	19	20	0.03	0.07	32
25	10	21	0.03	0.07	32
26	10	22	0.07	0.15	32
27	21	22	0.01	0.02	32
28	15	23	0.10	0.20	16
29	22	24	0.12	0.18	16
30	23	24	0.13	0.27	16
31	24	25	0.19	0.33	16
32	25	26	0.25	0.38	16
33	25	27	0.11	0.21	16
34	28	27	0.00	0.40	65
35	27	29	0.22	0.42	16
36	27	30	0.32	0.60	16
37	29	30	0.24	0.45	16
38	8	28	0.06	0.20	32
39	6	28	0.02	0.06	32

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FOREWORD *by EPSA*

The Electric Power Supply Association (EPSA) is the national trade association representing competitive power suppliers, including generators and marketers. These suppliers, who account for nearly 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities serving global power markets. EPSA seeks to bring the benefits of competition to all power customers. EPSA supports the continued formation of regional transmission organizations (RTOs), including essential features such as independent administration of the transmission system, real-time and day-ahead energy markets, and capacity markets. In addition, but not as a substitute for RTO markets, EPSA believes that all parties, and customers in particular, benefit from competitive solicitations for longer-term power purchases that are designed to be fair, accurate, and transparent. As such, it is useful to establish guidelines for the proper conduct of competitive solicitations, particularly in areas where RTOs have yet to be formed. This reference document is intended to assist policy-makers in establishing guidelines to ensure that competitive solicitations provide the best possible deal for electricity consumers.

FOREWORD *by Boston Pacific Company, Inc.*

Boston Pacific Company, Inc. is an energy consulting and investment services firm. Our clients include competitive power suppliers, electric utilities, electric and gas marketers, gas pipeline companies, trade associations, government agencies, public service commissions and energy consumers. This guidebook is based on our experience working in engagements on competitive solicitations conducted in primarily non-RTO areas, and in RTO areas, as well. It reflects the lessons we learned from these engagements, and is intended to help all participants in the competitive solicitation process get the process right. Getting the process right means ensuring that the competitive solicitation, from start to finish, is a credible process that results in the best possible deal for electric utility customers in terms of price, risk, reliability and environmental performance.

EXECUTIVE *Summary*

Although federal regulators have rightfully focused much of their effort in recent years on properly structuring shorter-term spot markets for energy and capacity under the auspices of independent regional transmission organizations (RTOs), the design of longer-term bilateral markets is equally important. Longer-term markets, in which power is procured on a multi-month, yearly, or multi-year basis, could—and in some regions do—satisfy 85 percent to 90 percent of power needs. Along with shorter-term markets, these markets provide the necessary price signals for development of new resources. And, because they involve longer-term commitments to sell power, they provide a significant opportunity to justify major capital investments in power plants and related infrastructure. Consumers benefit when suppliers take advantage of these opportunities by building new infrastructure, which both intensifies competition and increases reliability.

> Consumers benefit when suppliers take advantage of these opportunities by building new infrastructure, which both intensifies competition and increases reliability.

To many, the design of longer-term markets is synonymous with the design of competitive solicitations, which range from price-only auctions to more extensive requests for proposals (RFPs) that evaluate bids with respect to a long list of price and non-price criteria.[1] This guidebook is based on lessons learned from hands-on experience with competitive solicitations. It is meant to be a useful resource for all those charged with designing, implementing and/or monitoring these solicitations.

First and foremost, the goal of competitive solicitations is to evaluate a full range of resources in the wholesale marketplace to obtain the best possible deal for electric utility customers. In this specific sense, competitive solicitations, when conducted in a fair, accurate and transparent manner, are an important tool at both the state and federal levels for determining the

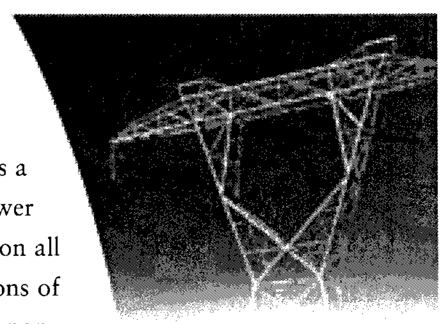
[1] Short-term markets such as day-ahead and real-time spot markets also use bid-based competitive solicitation formats; however, the focus of the guidebook is on longer-term competitive solicitations.

prudence of utility power purchase and investment decisions and allaying concerns about affiliate bias.

It is essential that the solicitation be credible to all parties, including electric customers, regulators, the utility buyer, and suppliers. The primary means of ensuring credibility are the use of (a) a collaborative process that adopts consensus-based solicitation rules upfront and (b) an independent, third-party monitor. The collaborative process includes specific opportunities for significant input from all participants early on, thereby streamlining the overall solicitation design, especially in contrast to full litigation. An independent, third-party monitor can help facilitate the collaborative process and oversee the solicitation itself. The purpose of the independent monitor is to provide assurances to all those involved in the solicitation that the process was fair, transparent and accurate.

The purpose of the independent monitor is to provide assurances to all those involved in the solicitation that the process was fair, transparent and accurate.

Once measures are in place to assure a credible solicitation, the format and product types to be solicited must be decided. Price-only auctions are best for markets in which there are standardized products, meaning that all aspects of the non-price bid evaluation can be settled beforehand. This, of course, adds greatly to transparency since only a single factor (price) determines who wins the solicitation. Price-only RFPs also are issued for standard products such as a share of full requirements service or blocks of power (e.g., 100 MW of firm power for 16 hours a day on all weekdays). Many RFPs, however, involve evaluations of (and allow variations in) a full range of price and non-price factors. Asset-backed or unit-contingent power is one example of a product solicited through these more complicated RFPs. Generally, auctions and RFPs conducted in the context of a well-functioning RTO can take much less time to start and run more smoothly than those in non-RTO areas.



Within a competitive solicitation, there are at least six key issues that need to be addressed to fairly and accurately evaluate bids:

- the principle of ***comparability*** means that all proposals should meet the same requirements and be evaluated under the same standards;
- ***transmission assessments*** for bidders during a solicitation should include an opportunity for any bidder to receive a timely and fair estimate of what it would take to become a network resource;
- when assessing ***cost-plus offers***, the evaluation should explicitly take into account the greater risk that these offers impose on customers as compared to pay-for-performance bids;
- financial theory supports using the annuity method when comparing offers of ***unequal lives***, and this should be at least one approach used during any bid evaluation;
- ***creditworthiness*** is a legitimate concern; however, collateral requirements must be set comparably and fairly for all parties, and contractual alternatives to collateral must be considered; and,
- in determining whether to assess a ***balance sheet penalty***, regulators should take the perspective of the utility customer, ask for evidence that a balance sheet effect actually occurred, and if the penalty is assessed, then ensure it is accurately calculated.

Ideally, all six of these issues should be settled during the collaborative process, along with all of the other solicitation rules and conditions, before the solicitation takes place. Doing so minimizes the potential for objections later on in the solicitation. Most important, settling these issues provides clarity to all stakeholders about the criteria that will be used to evaluate the bids.

All decisions for the solicitation should be guided by one goal: to obtain the best possible deal for customers by credibly evaluating the full range of resource alternatives offered.

Regardless of the solicitation format used, the product types solicited, or the approach to evaluation chosen, all decisions for the solicitation should be guided by one goal: to obtain the best possible deal for customers by *credibly* evaluating the full range of resource alternatives offered in the wholesale power market.

INTRODUCTION

I. INTRODUCTION: *The Importance of and Role for Competitive Solicitations*

In recent years, the focus on designing shorter-term power markets has overshadowed the importance of properly structuring longer-term markets. Longer-term power markets, in which power is procured on a multi-month to multi-year basis, are crucial to providing the necessary price signals for suppliers to develop new resources to meet a substantial portion of our future power needs. Because a significant amount of power can be procured for lengthy periods of time, mistakes in the design of longer-term markets can be costly to utility customers.

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For example, a long-term procurement decision that had substantial consequences in terms of cost, risk, and environmental performance was the construction of nuclear and other large baseload power plants during the 1970s and 1980s. The Federal Energy Regulatory Commission (FERC) reported that,

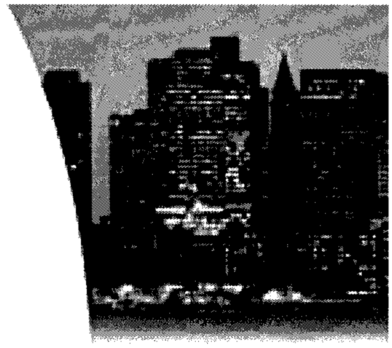
> "...expensive large baseload plants for which there was little or no demand, came onto the market or were in the process of being constructed. Accordingly, between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25 percent after adjusting for general inflation. Moreover, average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86 percent after adjusting for inflation."[2]

Again, the potential for significant, adverse consequences from poorly made procurement decisions make it especially important that long-term markets be properly designed. To many, the design of longer-term markets is synonymous with the design of competitive solicitations, which range from price-only auctions to more extensive requests for proposals (RFPs) that

[2] FERC Order 888 at p. 14.

evaluate bids with respect to a long list of price and non-price criteria. This guidebook is based on lessons learned from hands-on experience and is meant to be a useful resource for all those charged with designing, implementing, and monitoring competitive solicitations.

A A Tool For Modernizing State Prudence Review



By requiring utilities to demonstrate the prudence of their investment and procurement decisions, state regulatory commissions attempt to ensure that their energy consumers get the best possible deal on electricity in terms of price, risk, reliability, and environmental performance. The heart of prudence has always been a reasonable decision-making process in which all alternatives are evaluated side-by-side with information known and knowable at the time of the decision. This definition of prudence is reflected in a ruling in *Gulf States Utilities Company v. Louisiana Public Service Commission* by the Louisiana Supreme Court, which states that:

> Although there is no single formulation sufficient to express constitutional, statutory, or judicially derived standards for determining how much of a utility's investment in a particular plant should be included within its rate base, one of the principles used by ratemaking bodies and courts to make such a determination is the prudent investment standard... That is, the utility must demonstrate that it 'went through a reasonable decision-making process to arrive at a course of action and, given the facts as they were or should have been known at the time, responded in a reasonable manner.' *Re Cambridge Electric Light Co., 86 P.U.R. 4th 574 (Mass. D.P.U. 1983)*... the focus in a prudence inquiry is not whether a decision produced a favorable or unfavorable result, but rather, whether the process leading to the decision was a logical one, and whether the utility company reasonably relied on information and planning techniques known or knowable at the time. *Metzenbaum v. Columbia Gas Transmission Corp., Opinion No. 25, 4 FERC 161,277.*

An electric utility can use competitive solicitations to demonstrate prudence by showing that it used a reasonable decision-making process, meaning that it fairly evaluated the full range of alternatives. Indeed, in today's market, because so many alternatives are proposed by credible parties other than the regulated utility, and include more than just large-scale conventional power plants, competitive solicitations are essential to ensure that the utility has evaluated the full range of both utility and non-utility alternatives. In addition, many of these alternatives are from suppliers who, in contrast to traditional utility cost-plus offers, are willing to guarantee the customer benefits that they promise in their proposals, so the evaluation must take this customer risk-protection into account.

Using competitive solicitations to demonstrate prudence also can provide regulatory certainty to the utility. For example, if the solicitation meets certain standards, the state commission could establish a rebuttable presumption that the process results in a prudent investment or procurement decision; in any subsequent proceeding, the rebuttable presumption would shift the burden of proof away from the utility to intervenors. With this in place, the commission could generally review the solicitation process in a much shorter time. This determination of prudence would remove the risk that the utility would not be able to recover costs that were incurred as a result of the contracts signed through the competitive solicitation.

Regulatory certainty also is enhanced for competitive power suppliers in two ways. First, a quick review period minimizes the market risks to suppliers of keeping bids open for extended periods of time. Second, a determination of prudence obviates the need for a "regulatory out" clause in the Power Purchase Agreement (PPA).

B Allaying Concerns About Affiliate Bias

At the Federal Energy Regulatory Commission, a properly designed competitive solicitation can play a central role in allaying concerns about affiliate bias. In *Boston Edison Company Re: Edgar Electric Energy Company* 55 FERC *f* 61,382 (1991), FERC set forth three non-exclusive ways a utility could demonstrate the lack of affiliate abuse. One way is to offer evidence of "direct head-to-head competition," which means the utility uses some form of competition solicitation.[3] If a utility chooses this route, then the commission "seeks assurance" that (1) the solicitation process did not favor the affiliate; (2) the analysis of the bids or responses did not favor the affiliate; and, (3) the affiliate was chosen based on a reasonable combination of price and non-price factors. Moreover, if an affiliate is chosen and is *not* the least-cost option, the applicant must explain why that selection was made.[4] The concern here is primarily with affiliate abuse—when a utility unduly favors its affiliate's offer over other offers to the detriment of consumers. The *Edgar* precedent is useful because it establishes a threshold standard that a utility must meet when conducting competitive solicitations to demonstrate a lack of affiliate abuse. Getting longer-term market design right by conducting a fair, transparent and accurate competitive solicitation is essential to meeting FERC's *Edgar* standard.

C Overview Of This Report

Clearly, competitive solicitations can play a central role in evaluating resource alternatives so as to get the best possible deal for utility customers. At the state level, they can assist in modernizing the prudence review standard, and at the federal level, they meet the requirements of the *Edgar* standard for demonstrating the lack of affiliate abuse. But, what are the essential elements of a competitive solicitation? Section II (Ensuring a Credible Solicitation) examines the key elements that ensure the solicitation process is fair and credible, which include the use of the collaborative process and an independent, third-party monitor. Section III (Choosing a Solicitation Format and Product Type) describes different solicitation formats and product types. Section IV (Fair and Accurate Bid Evaluations) reviews important evaluative factors used in a competitive solicitation. The conclusion, Section V, emphasizes that accurate, credible, and transparent competitive solicitations ensure that customers get the best possible deal on electricity in terms of price, risk, reliability and environmental performance. Finally, three appendices delve deeper into technical details.

[3] *See Boston Edison Company Re: Edgar Electric Energy Company* 55 FERC ¶ 61,382 (1991) (Edgar).
[4] *Id.*

A CREDIBLE SOLICITATION

II. ENSURING *a Credible Solicitation*

Above all else, competitive solicitations must be credible to all. This can be achieved primarily through the use of (1) a collaborative process and (2) an independent, third-party monitor. The loss of credibility due to affiliate abuse or other deficiencies in the procurement process tends to "chill the market" because competitive suppliers will not submit proposals if there is a perception that the proposals will not be evaluated objectively.[5]

A Collaborative Process

One approach to establishing credibility in the solicitation is called the collaborative process. The intent is that a full consensus can be achieved during a collaborative process on most issues with respect to the solicitation, such as the amount and type of power to be procured and the evaluation criteria to be used. This process has three key steps: (a) the local utility submits proposed approaches to all aspects of the solicitation, including the definition of product types and bid evaluation criteria; (b) a series of multi-day, commission-facilitated collaborative meetings are held that allow for significant stakeholder input on the utility proposals; and, (c) the state commission promptly resolves outstanding issues that are not resolved within a specified time frame.

To illustrate the use of a collaborative process for an RFP, here are eight recommended steps:

1. The state commission chooses a monitor (ideally an independent, third-party monitor) to facilitate the collaborative process or work in conjunction with the commission staff to facilitate the process;
2. The utility submits its forecasted resource requirements to the collaborative process;
3. A multi-day collaborative meeting allows for an open discussion with the goal of gaining consensus on those resource requirements among market participants, commission staff and the utility. These

[5] Preparation of legitimate bids for long-term supplies typically cost $50,000-$75,000 to prepare, and competitive suppliers take these costs into consideration when deciding whether to bid.

estimates are key to defining the amount of power and types of products to solicit;

4. If consensus is reached, the resource requirement phase is over. If consensus is not reached, the independent, third-party monitor or staff would submit a report to the commission with recommendations on unresolved resource requirement issues. Other participants in the collaborative process also may file comments. The commission promptly resolves outstanding issues;

5. Next, the utility submits a draft solicitation package to the collaborative process;

6. The draft solicitation package provides the basis for another multi-day meeting in the collaborative process. These collaborative meetings would address issues such as bidder qualifications, the terms of a Model PPA if one is used, bid evaluation techniques and criteria, etc.;

7. If consensus is reached, the RFP design phase is over. If not, the independent, third-party monitor and/or commission staff reports to the commission with recommendations and the commission again settles any unresolved issues. Other participants also file comments, and the state commission promptly resolves outstanding issues; and,

8. The RFP is issued. While the local utility still is responsible for choosing the winning bids, the independent monitor has full access to all communication between the utility and bidders (most notably with the utility affiliate) through all phases of bid evaluation.

A process that incorporates stakeholder input can go a long way in building credibility. For a competitive solicitation in Arizona that addressed future needs for Arizona Public Service Company and Tucson Electric Power, the Independent Monitor wrote:

> in order for the Solicitation to attract wide participation, the process had to be accepted by participants as fair, open, and transparent. To achieve this, prospective bidders and interested persons who agreed to keep certain information confidential had the opportunity to review supporting data and draft documents in advance of the RFP... Many bidders and other interested persons provided comments to the util-

> ities, the Independent Monitor, or the Staff regarding the completeness or quality of the information provided. . . Bidders' conferences were held so that all interested parties had the opportunity to ask questions directly of the utilities as well as to identify deficiencies in the Solicitation documents or supporting data.[6]

State commissions and utilities might be concerned that using a collaborative approach will encourage litigation and thus delay the solicitation itself. However, limiting the time for and the types of objections allowed in the collaborative process can mitigate these concerns. For example, in a recent Florida Public Service Commission (FPSC) order adopting changes to the rules governing utilities' procurement of new resources, the FPSC limited the amount of time RFP participants had to file objections, and limited the types of objections to specific allegations of violations of the rule.[7] Within 30 days of filing the objection, the FPSC would determine whether a rule violation occurred. Commenting on these changes, the FPSC stated that, "[w]e believe these changes will ensure that the objection process does not cause unnecessary delays to the RFP process. These changes should also provide greater clarity and certainty early on in the RFP process, and should help streamline and reduce the number of similar objections in the need determination process."[8]

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B Independent, Third-Party Monitor

In addition to facilitating the collaborative process, an independent, third-party monitor also can add credibility by overseeing the entire solicitation process to ensure that there is no bias. For example, the monitor may perform an independent evaluation of the bids and monitor the communication between the utility and its affiliate.

[6] Independent Monitor's Final Report on Track B Solicitation to the Arizona Corporation Commission, Accion Group (May 27, 2003) at pgs. 6-7.
[7] *Order Adopting Changes to the Proposed Amendments of Rule 25-22.082, Florida Administrative Code* in Docket No. 020398-EQ (January 27, 2003) at p. 6.
[8] *Id.*

The benefit of an independent monitor is that the commission, staff, market participants and customers will have an extra pair of experienced eyes watching over the solicitation process. The monitor will know the mistakes that can be made and will possess the technical expertise to delve into the details of the utility's evaluation to determine any biases. Bidders gain peace of mind knowing that a fair and impartial entity is reviewing the details of the solicitation.

The decision on whether to use an independent monitor is driven primarily by three factors: (1) the desire to assist state regulatory commission staff with logistical and technical assistance; (2) whether a utility affiliate or the utility's self-build option participates in the solicitation; and (3) an assessment of the need to enhance confidence among stakeholders that the solicitation is credible.

For example, an Arizona Corporation Commission staff report on the process to be used for a competitive solicitation addressed two of the above points. Specifically, the report stated, "[t]o assist the Staff and to assure all parties to the Solicitation for power supplies that the process employed is conducted in a transparent, effective, efficient and equitable manner, an Independent Monitor will be appointed by the Staff of the Commission to oversee the conduct of the Solicitation."[9]

Of course, if an independent, third-party monitor is hired, it serves to complement, not replace, the state commission's staff. For example, in Arizona, a consultant was hired to work as part of a team with the commission staff, and in Maryland, a technical consultant was selected to assist in the bid evaluation phase of the solicitation.

Furthermore, an independent, third-party monitor would not supplant the utility's decision-making ability in the negotiation and signing of contracts—the utility still makes the decision on what resources to select. This is of particular concern for some utilities that fear that an independent third party or even commission staff would encroach on the utility's responsibility to determine the appropriateness of resource alternatives. Separately, commissions may be concerned over the costs of hiring an independent monitor. One way to defray these cost concerns is by assessing a non-refundable fee per bidder.

[9] Staff Report on Track B: Competitive Solicitation in Docket Nos. E-00000A-02-0051 et. al., (October 25, 2002) at p. 9.

CHOOSING A FORMAT

III. CHOOSING A SOLICITATION *Format and Product Types*

Formats vary along a spectrum from price-only bid evaluations to bid evaluations based on a long list of price and non-price factors. Once measures are in place to ensure a credible solicitation, the format and product types to be solicited must be decided. The right solicitation format is primarily dictated by the type of product being solicited. For example, price-only auctions and RFPs are best for markets in which there are standardized products, meaning that all non-price factors can be settled beforehand. This, of course, adds greatly to transparency since only a single factor (price) determines who wins the solicitation. Many RFPs, however, involve evaluations of (and allow variations in) a full range of price and non-price factors. Asset-backed or unit-contingent power is a good example of a product solicited through such an RFP.

A Requests for Proposals (RFPs)

In many non-RTO areas, RFPs are often used to solicit unit-contingent power supply (i.e., the services of a specific power plant). RFPs allow bidders to submit proposals that include a variety of capacity sizes, start dates, term lengths, and pricing structures.[10] For instance, with respect to term lengths, a utility may want to solicit a mix of five-, ten- and fifteen-year contracts to match its evolving needs and spread its market risk over time.

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[10]In addition, RFPs allow demand-side management programs and renewable resources to compete as long as they offer comparable terms.

to-head comparison between a utility built power plant and one built by a competitive power supplier. Note, too, that competitive power suppliers who are marketers can provide unit-contingent power. Consumers benefit because the competition drives the utility and competitors to offer better, tangible deals in terms of lower price, lower risk, higher reliability and superior environmental performance. An added benefit is that suppliers can bid generation that is not yet on-line so that the number of competitors and the intensity of competition are increased.

A downside to unit-contingent RFPs is that they increase the difficulty of comparing proposals due to the differences in the bidders' offers. This may potentially lead to less transparent comparisons by allowing the evaluating party more discretion in the methods used to compare different aspects such as term lengths, availability guarantees, capacity sizes and timing. More discretion means more opportunity for bias. However, the lack of transparency can be mitigated during the collaborative process by deciding on the criteria and evaluation methodology to be used in the RFP beforehand and by employing an independent, third-party monitor. For a more detailed description of an RFP for unit-contingent power, see Appendix A.

However, RFPs also can be used to solicit standardized products (in addition to unit-contingent power) and can do so in a very transparent manner. For example, Maryland's four investor-owned electric utilities (Allegheny Power, Baltimore Gas and Electric Co., Delmarva Power & Light Co., and Potomac Electric Power Co.) issued a price-only RFP to meet their standard offer service (SOS) obligations. The RFP requested proposals from suppliers to provide shares of full requirements wholesale supply service as defined by the PJM RTO.[11]

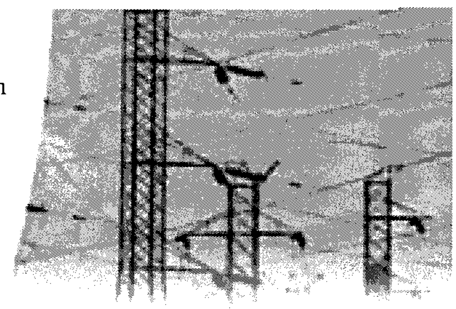
The RFP process and the model contract to be used was the result of a lengthy settlement effort involving the Maryland Public Service Commission (MPSC), the utilities and market participants. Key aspects of the RFP process and the RFP itself include: (a) the use of a technical consultant by the MPSC, who in conjunction with the MPSC Staff, monitors the entire RFP process from the flow of information to the actual evaluation procedures; (b) resolution of all non-price factors and contract terms prior to the solici-

[11]Full requirements wholesale supply service consists of capacity, energy, ancillary services and transmission losses.

tation via a collaborative effort; and, (c) the transparent evaluation of all bids based on a single discounted average price.

At the conclusion of the process, the technical consultant prepares a final report for the MPSC, which details the process and assures the MPSC that customers received the best possible deal.

B Price-Only Auctions



In price-only auctions, the winners are chosen solely on the basis of price (i.e., all non-price factors are settled beforehand). Another distinctive feature is that an auction employs multiple rounds of price bids. While there are various types of price-only auctions, the descending clock auction has gained credibility because it was the method used to procure roughly 18,000 MW of default service for customers in New Jersey. In a descending clock auction, an auctioneer announces prices in descending order until a price is reached at which the supply power offered is just sufficient to meet load.[12]

It is important to note that there can be price-only RFPs, too. For example, the 2004 Maryland Standard Offer Service RFP settled all non-price terms such as product types and credit standards. Suppliers will submit price-only offers for the provision of a share of full requirements service for specific customer types and contract lengths.

The primary difference between a price-only *auction* and a price-only *RFP* is the way prices are set. In the descending clock auction, the auctioneer

[12] An example of a different type of auction is the New York Independent System Operator (NYISO) new Installed Capacity (ICAP) auction system, also known as the ICAP demand curve. The auction determines the amount and price of ICAP each load-serving entity (LSE) must obtain for the following month. The NYISO auction system uses a downward sloping demand curve, which reflects the decreasing value of additional supply of capacity. The demand curve is administratively determined by the NYISO and is based on the cost of new entry and the decreasing value of installed capacity above the various locational ICAP requirements within the NYISO. For example, the demand price is set equal to the annualized cost of a new peaking unit at a capacity of 118 percent of peak load in each of the three areas: Long Island, New York City and the rest of New York State.

runs through multiple rounds of price bidding, but in the end, all winning bids are paid a uniform price. In the price-only RFP described in the previous section, bidders submit a price offer and winners are paid the price of each bid (i.e., non-uniform prices are paid).

Some benefits of price-only auctions and RFPs include: (a) the transparency of a price-only bid because all the non-price terms have been predetermined; (b) the limitation on the utilities' exposure to market risk by awarding the supplier a percentage share of the utilities' load rather than a fixed megawatt supply; and, (c) the limitation on the suppliers' exposure to keeping bids open—the turnaround time can be as short as a few days before commission approval. Possible downsides to auctions include: (a) a generally short-term length of purchase (i.e., one to two years for the awarded contracts) and (b) that price-only bids mean that there is no opportunity for suppliers to offer a lower price with less strict non-price requirements.

More information on the aforementioned descending clock auction for Basic Generation Service in New Jersey can be found in Appendix B.

BID EVALUATION PROCESS

IV. FAIR AND ACCURATE *Bid Evaluations*

This section examines six key issues involved in fairly and accurately evaluating bids: (1) the principle of comparability for all bidders; (2) transmission assessments of bidders; (3) cost-plus offers versus pay-for-performance bids; (4) comparing bids with unequal lives; (5) creditworthiness concerns; and, (6) balance sheet penalties. The important point in this section is that these issues should be openly settled during the collaborative process before the start of the solicitation. Generally, these issues become more contentious when evaluating bids in non-RTO areas. For instance, issues such as transmission assessments are contentious in non-RTO areas because there are no independent transmission authorities to make an objective assessment of the need for and cost of transmission upgrades.

A Comparability

The golden rule of comparability (treat others as you treat yourself) means that all bidders should meet the same requirements and be evaluated under the same standards so that no single bidder has an unfair advantage over another bidder. Two quick examples demonstrate this point. The first example involves a Firm Liquidated Damages (Firm LD) product, which requires the supplier to either provide power at the agreed-to price or pay any higher costs for replacement power. If a utility affiliate offers a Firm LD energy product in which the affiliate's bid is backed up by the utility's own generation reserves, then that utility should offer the same reserve service to all the non-affiliated competitors under the same price and non-price terms. To do otherwise would confer upon the affiliate an unfair advantage in the solicitation.

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The second example in which comparability is particularly pertinent is when a utility's self-build option is on a cost-plus basis. Cost-plus means the offer is not a fixed-price bid and the utility or its affiliate is able to come before the commission in the future to pass through costs such as unanticipated capital expenditures or major maintenance costs. In this instance, the utility or its affiliate can offer a lower price bid, knowing that it can come back before the commission to request recovery for unanticipated costs. This would confer an unfair advantage to the utility or its affiliate as compared to a fixed or fixed formula offer from a competitive power supplier, which must bid higher to account for added risk. The evaluation, as will be explained later, must take into account this difference in consumer risk.

B Transmission Assessments

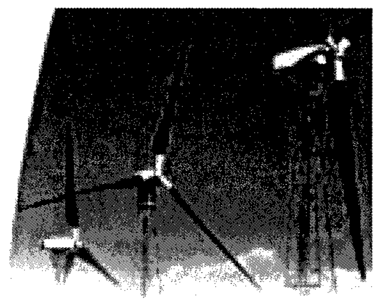
Assuring the reliability of a bidder's supply is a legitimate and important goal for a competitive solicitation in terms of both generation (physically being available) and transmission (physically being able to deliver). However, one key concern during bid evaluations is how to fairly and accurately assess the deliverability of a bidder's power. For example, a bidder rightly may be required to be a network resource to be eligible to bid. If so, the solicitation process should include an opportunity for any bidder to receive a timely and fair estimate of whatever system upgrades or other transmission-related costs that the bidder would incur to serve as a network resource.

Oftentimes, in the absence of RTOs, there are complaints of biased transmission assessments that inflate the amount of transmission-related costs necessary to ensure that electricity from a specific resource is deliverable. Further, there is the central question of who pays for upgrades. Outside well-functioning RTOs, there are sometimes allegations that the upgrades in question are in fact network upgrades and should be rolled in to rates not borne by bidders. Obviously, these issues are much easier to address in a well-functioning RTO area. In all instances, however, the most important principle is that all bidders should be *treated* comparably.

A different but related complaint is that, if transmission constraints are found for the moment with respect to certain bids, those bids might be rejected for the entire term of the proposal, which could be up to 25 years.

As already noted, deliverability of power should be an important factor in evaluating bids, but there are ways to evaluate this factor without rejecting bids for the entire term. From the customers' perspective, if the cost of upgrades to relieve the constraint is included in the price of a bid and the bid is still the lowest price bid, then a contract should be signed with that supplier on the date deliverability is available; interim service can be procured from other suppliers, including the utility affiliate.

C Cost-Plus Offers



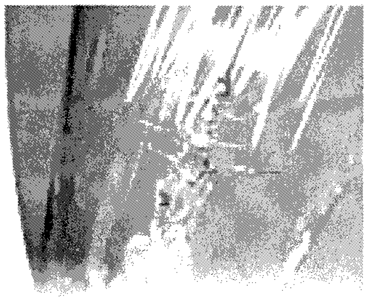
The concern here is how to properly evaluate the higher risk that cost-plus offers impose on customers as compared to fixed-price offers. In a cost-plus offer, the bidder does not guarantee the customer benefits asserted in that bid. In contrast, bidders offering a pay-for-performance PPA are willing to guarantee the customer benefits asserted in their proposals.

This concept of cost-plus versus fixed-price offers can be best demonstrated through the analogy of a customer taking bids to get his or her house built. One builder comes to the customers and says, "I think I can build the house you want for about $250,000, and I think I can build it with the features you want. However, I will not sign a contract that guarantees the price nor what features the house will have, but you will pay all costs I incur, pay me a profit on top of that, and accept the house as built." This is the cost-plus builder. Another builder says, "I will build the house you want for $250,000, and I will guarantee that price as well as the features of the house by signing a contract. If it is not what you wanted, you do not have to take it." This is the pay-for-performance builder. It would seem implausible that a customer would ever choose the cost-plus offer over a readily available pay-for-performance contract. The added risk of cost-plus is too much to bear.

If a solicitation in the electricity business does allow cost-plus offers to be submitted during a solicitation, the added risk to customers must be addressed. One approach is to limit the payments the cost-plus seller receives to the estimates provided by the seller in its offer during the solicitation. For example, if the seller offers the utility a cost-plus formula, but estimates (for comparison of bids) that the capacity payment will be roughly $95/kW-yr (again not guaranteed), then the commission should limit all payments to the supplier to $95/kW-yr over the full term of the contract. This would help protect customers by forcing cost-plus offers to have a more realistic appraisal of the costs that will actually be incurred.

Another approach is to apply a risk premium to the cost-plus offer in the evaluation of bids. The risk premium could be based on historical experience on cost pass-throughs with similar technologies. For example, if cost pass-throughs raised rate base by 20 percent in the past, the capacity related price in the cost-plus bid would be raised by 20 percent for purposes of bid evaluation.

D Unequal Lives



How should a utility choose between a lower priced offer to supply power for 10 years (say at $40/MWh) and a higher priced offer for 20 years (say at $50/MWh)? Clearly, for the first 10 years, the $40/MWh offer wins easily. The issue is how the two offers compare in the second 10 years. What should be assumed about what replaces the 10-year offer?

One approach that allows for more transparency is the use of the annuity[13] method, and while it need not be the only method used, it should be among the methods used when comparing offers of unequal lives. Indeed, financial theory dictates the use of the annuity method to compare options that have unequal lives. That is, the two proposals should be compared on the basis of their annuities. The annuity of the 10-year offer would be calculated over 10 years and that of the 20-year offer would be calculated over 20 years. The proposal with the lower annuity is the better choice.[14]

[13]An annuity is an equal annual payment over the life of the investment that has the same present value as the actual, unequal annual costs of the investment.

[14]This method is recommended by financial textbooks for evaluating investments or purchases of unequal lives because it is incorrect to directly compare the net present value of projects that have unequal lives.

Again, it is important to note that with any approach, assumptions must be made about what happens when the shorter-term proposal expires. With the annuity approach it is presumed that the initial offer is repeatable. This means that the gap between the 10- and 20-year options would be filled by assuming that the 10-year option would be repeated over time. An alternative is to allow the utility to assert the price and terms of the power supply in the years between the two offers. For example, a utility may "fill in" the second 10 years of the shorter-term offer with the assumed cost to build a new power plant a decade later. The primary appeal of the annuity method (as compared to the fill-in method) is that it lets the bid speak for itself. This greatly enhances the credibility of the solicitation process because it does not allow any bias to occur by letting the utility (a competitor) speak for that bidder.

In addition, making assumptions about the costs that a bidder would be willing to offer in the remaining years is challenging, given the many opportunities for technological advancement (e.g., a hydrogen-based fuel economy and decentralized generation). In other words, a utility may have an opportunity to purchase power in years 11 through 20 from a different supplier that may use more advanced, cheaper and environmentally friendly technology. Technological change makes the fill-in method fraught with uncertainty.

E Creditworthiness Concerns

State commissions are rightfully concerned about how power suppliers will contractually fulfill their obligations to utility customers. This concern manifests itself during competitive solicitations in the types of creditworthiness requirements imposed on bidders. Ideally, market participants would address ways to mitigate these concerns during the collaborative process. The goal is to openly discuss and agree upon these issues so that all parties know and understand their obligations.

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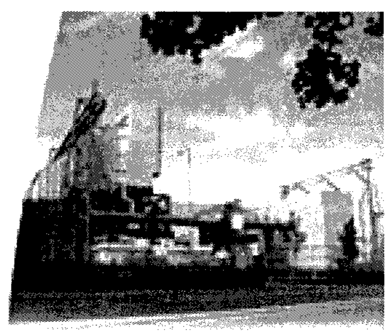
Both the nature of the risk being addressed and the full range of ways to mitigate that risk should be discussed. For example, consider the risk that a specific power plant will be available to run when a supplier is in financial distress. To address this risk, participants in the collaboration could discuss a model PPA that could include certain terms and conditions to protect customers such as measures that could "physically" give customers comfort by knowing that they can have access to the power plant in the event of trouble or default.

Additional requirements for both asset-backed and financial (non-asset backed) offers that can provide additional comfort include provisions for the supplier to pay for the replacement cost of power. At the outset, it must be confirmed that all bidders — utility and non-utility alike — face this requirement. This is important, since traditional cost-plus rates do not include the requirement to pay for replacement costs. A requirement to pay for replacement will require an assessment of the bidder's financial status and may trigger collateral requirements. Again, comparable standards must be applied to all bidders. The amount of collateral required may be tied to (a) the buyer's replacement cost exposure and (b) the suppliers' financial status in terms of bond rating and net worth. Collateral requirements can be typically met by either (1) cash, (2) a parent guarantee, and/or (3) a letter of credit. These requirements, individually or as a combination, can be used to mitigate risks to the customers.

F Balance Sheet Penalty



A few state commissions have allowed their utilities to reflect in the bid evaluation process a possible adverse effect on the utilities' balance sheets from signing a PPA with a third party. The motivation for this comes from financial ratings agencies such as Standard & Poor's (S&P), who assert that the capacity payments in a PPA are to some extent, in some circumstances, the equivalent of debt. The argument for reflecting this in bid evaluations is that, with this added "debt equivalent," the utility will have to add more equity to its balance sheet. Since equity costs more than debt, there is a cost to signing the PPA and that cost should be used as a penalty against non-utility bids.

Two questions then arise during the competitive solicitation process. First, should the utility assess a "balance sheet penalty" to the third-party suppliers when evaluating proposals? Second, if it is assessed, how should it be calculated? The second question is answered in detail in Appendix C, "Hypothetical Example of the Calculation of the Balance Sheet Penalty." If a penalty is imposed, it should be calculated fairly and accurately because it could potentially add millions of dollars to the total cost of non-affiliate proposals and bias the results of the competitive solicitation in favor of the utility.

As to whether the balance sheet penalty should be assessed, each market participant may have its own viewpoint. However, the state commission should take the viewpoint of the utility's customers. Taking their viewpoint is important because they, and not the utility stockholders and debt investors, are the ones that will be paying for the power and for any penalties applied.

From the customers' perspective, if the penalty is imposed, they would ask the commission 'why, if the utility or the affiliate loses in the competition to supply power because its power is higher cost and/or higher risk, should the commission reward the utility by increasing the amount of equity return it receives?' Stated more bluntly, as a reward for not offering the best deal to customers, the utility is asking the commission to approve an increase in rates so that its equity investors can earn more return on equity.

Also, from the customer viewpoint, the commission should ask what level of debt obligation customers would prefer. If the utility had two options, either (a) build a plant that requires $150 million in debt investment or (b) enter into a PPA with a non-affiliated supplier with capacity payments that have a present value of $150 million, which would the customer choose? To put a fine point on this, just think of the consequences of the worst case — the power plant simply fails to work after it is brought into commercial operation. With the pay-for-performance PPA, the customer owes nothing, because if there is no performance, there is no payment. In sharp contrast, with the utility's self-build or lease option, directly or indirectly, the customer is on the hook for $150 million. Again, the customer clearly would choose the pay-for-performance option.

State commissions must see that S&P looks at this with the exclusive perspective of that of the debt investor, not the customer perspective. S&P's intent is to alert the debt investor to the possible off-balance sheet obligations of a company that could compete for payment with loan repayment at times of financial distress for the utility. Rather than just passively going along, utilities can work with S&P to understand the terms and conditions of the PPA and that if determined to be prudent, the PPA payments will be made and do not compete with debt repayment. This may sway S&P to determine that no debt equivalent should be calculated.

CONCLUSION

V. CONCLUSION

Regardless of the solicitation format used, the product types solicited, or the approach to evaluation chosen, all decisions for the solicitation should be guided by one goal: to obtain the best possible deal for customers by *credibly* evaluating the full range of resource alternatives offered in the wholesale power market. If designed properly, competitive solicitations can be used to determine the prudence of resource procurement decisions and demonstrate the lack of affiliate abuse. However, in order for the results to be credible, the competitive solicitation should be fair and transparent. Such credibility can be achieved via the use of a collaborative process and/or an independent, third-party monitor. Ideally, the collaborative process settles as many issues as possible before the solicitation proceeds so that all involved have a clear understanding of what the solicitation entails. In the end, customers, utilities and state commissions want to buy power that is reliable and affordable, and competitive power suppliers want to sell their power. Properly designed competitive solicitations can result in an outcome in which consumers are assured of receiving the least-cost power available from the best mix of resources.

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APPENDIX *A*

EXAMPLE *of an RFP for Unit Contingent Power*

(MEANT TO ILLUSTRATE THE ISSUES FACED; IT IS NOT OFFERED AS A TEMPLATE FOR RFP DESIGN)

The purpose of this exhibit is to give an example of the methods that could be used to develop an open and fair competitive solicitation through the use of a request for proposals (RFPs) for unit-contingent power. This exhibit is based on a document distributed for an actual collaborative process in which it served to guide the discussion for this type of solicitation and product. It is believed to list the measures needed to obtain the best deal for customers in terms of price, risk, reliability and environmental performance. All the specific features would be tailored to the actual customer needs in a specific area of the country.

PRODUCTS

If the RFP solicits unit-contingent asset-backed offers, then the product should include capacity and energy. Potential bidders would include unit sales and system sales.

- Asset-backed unit-contingent offers allow customers to receive the benefits of dispatchable generation similar to the utilities' own generation.
- System sales include bids that identify a system or portfolio of assets.
- This does not require that a bidder have ownership of the asset(s); instead it requires that a bidder show proof that it has control of the asset(s), and that the asset(s) is deliverable.

RESOURCES

All types of resources (i.e., generation, distributed generation, demand-side management, renewables, portfolio bids, etc.) are allowed to submit bids provided that their bid identifies an asset(s).

- Bidders must demonstrate that they are able to provide the product that is being solicited (i.e., demand-side bids will be accepted if they can demonstrate that they are effective alternatives to peaking capacity).

- For portfolio bids, if a seller offered a bid that identified a portfolio of assets, the seller must prove that each asset is deliverable to the utility. Then, when the energy is required to be scheduled by the utility (this is likely to occur 24 hours in advance of delivery, but the utility would have some discretion in this regard), the bidder would identify the precise asset(s) that will be used.

CODES OF CONDUCT / AFFILLIATE RULES

- If an affiliate of the utility bids, then it will be evaluated under the same rules as any other bidder and must be held to its bid if it wins.
- The commission should impose a "zero tolerance" standard. That is, if any significant misconduct occurs before or during the solicitation by the utility or the affiliate that results in an unfair advantage toward an affiliate, then all affiliates should be banned from the solicitation.

LENGTH OF CONTRACTS

The RFP should solicit a range of contract terms to develop a diversified portfolio and protect customers.

- The utility will file with the commission its portfolio-term preferences for approval (e.g. the utility prefers 60 percent of the RFP capacity procured under 10-year terms, 20 percent under 5-year terms, 10 percent under 3-year terms, and 10 percent under a 1-year term). This preference will be made public as part of the collaborative RFP process.
- The commission should promote customer risk protection by establishing an incentive system for load serving entities to better manage price and volatility risk.

STRUCTURE OF PRICE BID

All bids submitted in the RFP shall include the following features to ensure that (a) the customers will receive reliable products and services and (b) the suppliers are accurately compensated for those products and services.

1. Capacity Price: This will ensure that the resource is available to supply capacity and energy.

    - Stated in $/kW-year for each year of the contract term; or, initial-year stated and then indexed to inflation.

    - The capacity price must be tied to an availability guarantee.

2. Availability Guarantee: This will ensure that the customers are protected against poor performance.

    - The capacity price would be paid in full if, and only if, the facility was available for service 95 percent of the time, on average, over the previous 12 months. If it was available for less than 95 percent of the time, capacity payments would be reduced proportionally, and the seller would be responsible for the replacement cost of power. If the performance fell below 50 percent availability, no capacity payment would be made.

    - If availability was above 95 percent, then the supplier would receive a proportional bonus for each percentage point above 95 percent.

    - A guaranteed megawatt output will be stated.

3. Energy Price: Compensates the supplier for providing energy to the customers.

    - The energy price will either be a fixed price ($/MWh) stated for each year; or,

    - Stated as a guaranteed heat rate and a fuel price tied to some publicly available fuel price index.

    - Gas tolling offers are acceptable and, in this case, a guaranteed heat rate must be offered.

    - For portfolio bids or system sales, the bidder would have a single fixed energy price or heat rate for all the assets.

4. Fixed Operation & Maintenance (FO&M) Cost

    - An explicit fixed cost in terms of $/kW-year for each year of the contract length, or an initial-year price indexed to inflation.

    - FO&M also will be tied to the availability guarantee.

5. Variable Operation & Maintenance (VO&M) Cost

   - VO&M will be a fixed price in terms of $/MWh stated for each year or an initial-year price indexed to inflation.

   - Start Price: The cost in $/start can be fixed or tied to a publicly available index.

MODEL PPA

The RFP should include a model PPA to be used as a template for bids. This PPA will detail all the required and/or preferred price and non-price terms. The goal is to streamline the bid evaluation process by settling most contract issues upfront. The following items are some specific features that should be included in the model PPA to ensure that bids can be compared equally.

1. Dispatchability: Each generation asset is dispatchable based on its energy price plus VO&M plus transmission losses. Each bid must submit the necessary parameters for dispatch such as:

   - Minimum load level,

   - Ramp rates,

   - Minimum run times, and,

   - Start-up times.

2. No Regulatory-Out Clause

   - The RFP itself will be the prudence review, and, therefore there is no need for an ongoing prudence review of the contract. Since there is no risk of a disallowance, there is no need for a regulatory-out clause.

3. *Force Majeure* will be defined using the industry standards for events out of the control of the parties.

4. Security Deposit

   - Construction Period Security Deposit shall be in the form of a letter of credit (or an acceptable substitute) for $30,000/MW and be applicable from the date that the winning bidder(s) signs the PPAs until the in-service date of the asset.

   - Operation Period Security Deposit shall be in the form of a letter of credit (or an acceptable substitute) for $30,000/MW and be applicable for the entire term of the contract.

- Additional security in the form of a second lien (secondary mortgage) on the asset(s) also could be imposed as recourse when a default occurs.

5. Construction Milestones

   - If a bidder's asset is not on-line, it must contractually guarantee to meet milestones, such as the completion of permitting, financial close and equipment delivery.

6. Liquidated Damages

   - A bidder is liable for the replacement cost of power in the event of (a) early contract termination, (b) under-performance, or (c) failure to meet in-service date.
   - The Construction or Operation Period Security Deposits are the source of payment and set the limit for replacement costs.

7. Creditworthiness: Prospective bidders may submit bids only if they meet one of the following creditworthiness standards:

   - Bond rating of the company is investment grade;
   - The asset to be bid has been financed;
   - The asset has an investment grade guarantor; or,
   - Both Construction and Operation Period Security Deposits are increased to $100,000/MW.

BID EVALUATION IN THE RFP

If an affiliate of the utility participates in the solicitation, an independent monitor could be selected and hired by the commission to work alongside the commission staff to ensure fair treatment for all bids. The independent monitor should be deeply involved in the details of the evaluation process (i.e., ensuring that the details do not favor one participant over another).

The bid evaluation will be in two stages. The first will consist solely of an assessment of generation costs, and the second will take into account possible transmission system upgrade costs.

Stage One: *Generation Cost Assessment*

1. The initial generation cost bid evaluation will be done across a range of uniform capacity factors. The monitor, selected by the Commission, will specify the uniform capacity factors to be used (e.g., 10 percent, 20 percent, and so on) and each bid will yield a price at each capacity factor (a screening curve).

2. In addition to specifying the uniform capacity factors, the independent monitor will specify all other assumptions for evaluation such as natural gas prices or other fuel costs, and inflation.

3. With the uniform capacity factor evaluation, the costs will be represented as an annuity cost per MWh. The steps are as follows:

   - The annual costs for each price component (capacity, energy, VO&M, FO&M and starts) will be projected over the proposed term of the offer, at each of the uniform capacity factors.

   - The present value of these projected costs will be determined using the utility's after-tax weighted cost of capital as the discount rate.

   - To compare the contracts with unequal lives (i.e. a three-year contract as compared to a five-year contract) the bid evaluation should follow the annuity method. To be clear, if a 3-year offer is made, a 3-year annuity would be calculated. If a 5-year offer is made, a 5-year annuity would be calculated.

   - To adjust for unequal bid sizes, the annuities would be divided by the MWh of the bid, as dictated by each uniform capacity factor.

   - The monitor will rank the annuities per MWh and choose the lowest-cost bids sufficient to meet the megawatt level solicited.

4. If the monitor is satisfied with the uniform capacity factor evaluation, it need not go further in the generation cost evaluation. If, however, the monitor wants an additional analysis, it is entirely appropriate to add a production simulation based-bid evaluation.

   - Capacity factors for each bid would be determined through production simulation.

- Bid comparison would be done on the basis of the cumulative present value of the revenue requirement adjusted for differences in contract term and project size.

Stage Two: *Transmission System Upgrades Cost Assessment*

1. The winning bidders, based on generation costs, as a group, will be called the Minimum Supply Cost Portfolio (MSCP).
2. Transmission modeling will be used to determine the system upgrade costs, if any, associated with the MSCP. System upgrades will be made to assure reliability criteria are met.
3. The determination of system upgrade costs must be performed in a comparable manner for all bidders.
4. The cost of the MSCP is now reassessed taking into consideration transmission system upgrade costs. If the MSCP is judged to still be the lowest cost to customers, then the MSCP is the winning portfolio.
5. If the MSCP is clearly not the lowest cost portfolio, another portfolio of generation bids will be created. This will be called the Second-Best Supply Cost Portfolio (SBSCP). The SBSCP will include higher-cost generation bids that are expected to require lower transmission system upgrades. Transmission modeling will be used to determine the system upgrade costs of the SBSCP.
6. The costs of the MSCP and SBSCP now would be compared with the transmission costs included. The annuity cost of transmission upgrades would be added to the annuity cost of the generation bids. The lower cost portfolio would win.

LOAD-POCKET LOCATION

A separate analysis for load-pocket location for generation is required to determine if, and only if, system reliability requires load-pocket location for physical needs regardless of transmission capability.

- If a load pocket is a result of insufficient transmission capability, it is an economic decision captured in the transmission cost analysis detailed above. That is, if the cost of (a) generation outside the load pocket plus the cost of required system upgrades is more expensive than (b) the cost of in-pocket generation, then in-pocket generation will win the RFP without any locational preference. There is no need for a location preference if the reason for the load pocket is insufficient transmission capability.

- The utility may allow bidders to co-locate facilities with the utility, as possible, on its existing load pocket sites.
- If the utility mothballs or retires in-pocket units, it will include in the RFP a price at which out-of-pocket bidders may call on these units when transmission constraints are binding.

OTHER ISSUES

- Although many non-price factors are made comparable by the Model PPA, the value of non-price factors in bid evaluation must be made clear in the RFP evaluation process beforehand. For example, some value can be assigned to having completed construction or being in an advanced stage of construction.
- Confidentiality: All bids are confidential. The PPAs from winning bids may be made public upon contract signature.
- Dispute Resolution: Each bidder may be entitled to a post-bid meeting with the Bid Evaluation Team if it is omitted from the short-list, or it is not a winner after being on the short-list. If a grievance remains, losing bidders (a) will agree to arbitration on matters concerning the evaluation of its bid or (b) can appeal to the commission for serious breaches of procedure only. The entire RFP must be re-opened if procedural breaches are found to benefit the utility or its affiliate.
- Bid Fee: A non-refundable $8,000 fee per bidder (covering up to three bid alternatives) will be assessed to defray the cost of the independent monitor.

APPENDIX *B*

EXAMPLE *of a Price-Only Auction*
(NEW JERSEY BASIC GENERATION SERVICES AUCTION)

The purpose of this exhibit is to give the commission an example of the methods to be used in developing an open and fair competitive solicitation through the use of an auction format. The example described is from New Jersey's Basic Generation Service (BGS) Auction.

NEW JERSEY'S BASIC GENERATION SERVICE AUCTION

In February 2003, New Jersey's Electric Distribution Companies (EDC) successfully utilized a declining block auction to supply BGS.[1] It should be noted that this auction was performed under the structure of the PJM Interconnection and thus under an open and level playing field for participants. With that in mind, this description of the New Jersey Auction is included to aid in the understanding of this form of competitive solicitation.

The state's four incumbent EDCs: Public Service Electric and Gas Co. (PSE&G), Jersey Central Power & Light Co. (JCP&L), ACECI/Conectiv Power Delivery (Conectiv), and Rockland Electric Co. (RECO) held a descending clock auction to bid out their BGS load. Roughly 18,100 MW was solicited for two products. The first product, Fixed Price (FP) service, for small to mid-size customers, pays suppliers a fixed price (in cents-kWh) to cover their costs (suppliers must use this price to cover capacity, energy, ancillary service and transmission costs). The peak capacity solicited for this product totaled approximately 15,500 MW. The second product, Hourly Electric Price (HEP) service, for large customers, pays suppliers a capacity payment ($/MW-day) which is determined in the auction and an energy payment determined by the PJM zonal real-time hourly market. In addition, suppliers are paid the pre-specified ancillary service rate and transmission rates according to PJM's Open Access Transmission Tariff (OATT). The capacity solicited for this product totaled approximately 2,600 MW.

[1] More information is available at http://www.bgs-auction.com.

DESCENDING CLOCK AUCTION DETAILS

According to the auction rules, each EDC's peak BGS load is divided into roughly (a) 100 MW tranches for the FP product and (b) 25 MW tranches for HEP product.[2] An auctioneer runs the solicitation by stating the initial price of each EDC's tranche, then the suppliers bid for the number of tranches they would like to serve. If the total number of tranches bid by the suppliers is greater then the number of tranches desired by the EDC, the auctioneer would hold another round of auctions and "tick down" or lower the price. This continues until the number of tranches offered by suppliers equals the number of tranches desired by the EDC.

The winning bidders are awarded a fixed percentage of the EDC's load based on the number of tranches won. For example JCP&L wanted to offer 30 tranches (roughly 30–100 MW blocks) for their 10-month FP product. If a bidder won five tranches it would provide full service requirements for one sixth (5/30 tranches) of JCP&L's BGS load in all hours. In short, suppliers are not guaranteed a fixed number of megawatts, but rather a right to serve a fixed percentage load.

A winning supplier provides full-requirements service. That is, the provider is responsible for fulfilling all the requirements of a PJM Load Serving Entity (LSE) including capacity, energy, ancillary services and transmission, and any other service as may be required by PJM. A supplier may win one or more tranches for one or more EDCs and for one or more terms.

TERM LENGTH

The length on contract terms in the auction is short term. The FP auction awarded two-thirds of the tranches to 10-month contracts and one-third to 34-month contracts. The HEP auction awarded contracts for 10 months of service.

[2] Each tranche (or block of power) is actually slightly less than 100 MW for FP to make the number of tranches a whole number. E.g. JCP&L's peak load is 2,973 MW, but in order to have 30 equal size tranches the megawatts must be reduced to 99.1 MW per tranche. (99.1 MW x 30 tranches = 2,973 MW)

CONTRACT

Once the auction is closed, the prices are final. There are no negotiations and suppliers are required to sign a predetermined contract. While the auction price is final, the price actually realized by suppliers varies by season. Built into the auction are seasonal factors (greater than one for summer, less than one for winter) that are multiplied by the auction price to take into account seasonal variability. The factors vary by EDC for the summer from 1.11 to 1.24 and for the winter from .92 to .96. For example, PSE&G's 10-month FP closing auction price was 5.386 cents/kWh. Its summer factor is 1.1423, therefore the price charged during the summer months is 6.152 cents/kWh.

RESTRICTIONS

- Each bidder must post a letter of credit or bid bond of $500,000 per tranche for the FP service (translates into roughly $5/kW) and $125,000 per tranche for the HEP product for the number of tranches offered in the first round of bids. Depending upon creditworthiness, an additional security deposit could be required.
- Each EDC submits a load cap on the number of tranches any one bidder is allowed to serve. The goal is to prevent any one bidder from influencing the auction and overexposing the EDC to a single supplier.
- There are minimum and maximum statewide starting prices. The EDCs agreed upon two prices to give the auctioneer a range of values to begin the solicitation.

APPENDIX C

HYPOTHETICAL *Example of the Balance Sheet Penalty*

While we do not recommend the use of the balance sheet penalty in the evaluation of bids, if it is used in some context, there are several steps involved in calculating the balance sheet penalty. First, the utility calculates the present value of the capacity payments as defined in the PPA using the utility's after-tax weighted average cost of capital as the discount rate.[3] Next, the utility assesses the risk level associated with the PPA and multiplies the risk percentage times the present value to get the imputed debt. The next calculation is the required equity needed to keep the debt-to-equity ratio consistent with the utility's original balance sheet, prior to the execution of the PPA. The utility then imputes a pre-tax interest payment (based on the utility's equity return) necessary to support the imputed debt.

To illustrate, Table One presents a hypothetical example of the calculations. First, the present value of the capacity payments for our hypothetical PPA is $150 million.

Second, the utility asserts that 12 percent of that present value of capacity payments is the equivalent of debt. This leads the utility to add $18 million of what is imaginary debt to its balance sheet to reflect this debt equivalent; with the addition of imaginary debt, we will refer to this as the utility's hypothetical balance sheet.

Third, because the addition of this imaginary debt means that the utility will have a higher debt-to-equity ratio, the utility asserts that it will have to add equity to restore the debt-to-equity ratio it would have had prior to signing the contract. The utility declares that it wants debt to be 40 percent of its total capitalization. If the utility wants to regain its 40 percent debt share, it must add $27 million of equity to its balance sheet. Thus, it will add a total of $45 million to its hypothetical balance sheet with $18 million (40 percent) coming from imaginary debt and $27 million (60 percent) coming from equity.

[3] The assumed discount rate is 11 percent and it is not forced to be equal to the cost of capital for the hypothetical equity-debt swap.

Fourth, if $27 million in equity must be added, then the utility claims that customers must pay the pre-tax return on equity for that added equity investment. The utility asserts that the pre-tax return is about 18.5 percent (an after-tax rate of 12 percent grossed up for income taxes of 35 percent). In the first year, the added return on equity would be $4.98 million ($27 million multiplied by .185). The utility calculates this added return on equity for each year of the PPA; the dollar amount of return declines each year because the amount of equity is shown to decline each year due to depreciation.

Fifth, before the penalty is applied, the utility deducts from the penalty the cost of debt, since in reality the utility is asking to simply swap equity for debt. (Actual total capitalization does not change, since the PPA causes only imaginary debt.) Thus, the net cost is the equity return less the debt return that would have been paid.

Sixth, the utility calculates the present value of these added annual returns on equity after deducting the cost of debt. This present value of annual equity returns after deducting the cost of debt is the balance sheet equalization penalty that the utility assesses against the competitive power suppliers. Assuming a 20-year straight-line depreciation, our example would lead to a $20.4 million penalty. That is, the utility would treat the $20.4 million penalty as if it were a cost of signing the PPA, thus giving the utility's own power plants an artificial cost advantage. In this example, that advantage amounts to artificially increasing the competitor's capacity cost by 13.6 percent on a present value basis ($20.3 million divided by $150 million).