Electricity Prices in PJM:

A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs

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Executive Summary

This report describes our work in understanding rate trends for electric generation within the PJM Interconnection (PJM) region, specifically to illuminate the effect of restructuring on prices. We estimate and compare two sets of annual prices: (1) the actual wholesale power costs (WPC) in the PJM market, and (2) prices in a scenario with economic regulation continued from the mid-1990s to today so that the generation service costs (GSC) are the unbundled generation portion of the pre-deregulation cost-of-service rates. We examined three companies in the region: Delmarva Power & Light in Delaware (Delmarva), Jersey Central Power & Light in New Jersey (JPCL), and the Pennsylvania Electric Company in Pennsylvania (Penelec). We considered all five of the calendar years since the beginning of PJM market operation – 1999 through 2003.

Most of the work on this project involved unbundling the pre-deregulation prices using primary information from the Companies' FERC Forms 1. In addition, because appropriate comparisons should recognize changes in system parameters such as the cost of various fuels, we develop a method for "indexing" the GSC, effectively projecting those costs from 1996 through 2003, as if regulation had been continued. There are, of course, many assumptions and judgments required in this task, and these are described in Section 3 of our report.

In conclusion, we find that, while PJM deregulated costs fluctuate year-to-year, on average, the WPCs over the five year period 1999 to 2004 have been lower than the indexed GSCs. This conclusion is, however, subject to (at least) five important caveats. First, while our approach is reasonable, data limitations required the use of highly simplified assumptions about trends in capital costs, taxes, and other factors. And specifically, the indexed GSC costs are "high" in that they include all the "stranded costs" that were collected in transition charges and, likely, some that were not, and they also do not include mandated retail rate reductions productivity improvements in utility-owned generation or overhead operations. Second, the WPCs were calculated without any explicit incorporation of transmission costs, something that might readily be done now based upon the results of PJM's recent auction of transmission rights. Third, the WPCs are strictly generation costs in the PJM wholesale markets and do not include some factors that may be in the actual prices that customers are paying at retail such as "retail adders" for marketing costs, perceived risks to suppliers, and market power. Fourth, the WPCs over the past few years have been lower than were previously expected as a result of capacity surpluses from the addition of new generating plants in the region, a situation which customers will not enjoy indefinitely. And fifth, we have examined only three case study companies, and it is conceivable that analysis of other companies in PJM would show different results.

Each of these five points suggests possible additional research that would be useful in understanding the effects of restructuring in the PJM market. We hope that this current study is helpful in developing the methodologies and illuminating the issues involved in such analysis. We believe that it illustrates some of the economic effects of restructuring in a manner that has not, to our knowledge, been previously attempted. We look forward to comments, refinements, extensions, and question about this work.

1. Introduction

1.1 Overview of the Study Methodology

PJM hired Synapse Energy Economics to analyze the costs of generation before and after electricity market deregulation. Specifically, we were asked to examine the generation costs that were embedded in the pre-restructuring regulated prices for electricity and to compare those costs with the electricity market prices in the deregulated wholesale markets operated by PJM. We set out to calculate and compare 1996 generation service costs ("GSC") with 2002 wholesale power costs ("WPC").

In conducting this research, a number of issues arose requiring the initial work plan to be revised and extended. Specifically, we determined that a simple comparison of pre-deregulation prices with post-deregulation prices could be misleading, unless it accounted for the changes that would have occurred to the regulated cost-of-service prices overtime in the absence of deregulation. For this reason, we "indexed" the pre-deregulation generation service costs, effectively projecting them forward in time to the present, in order to provide an appropriate basis for comparison.

In addition, we found that the year 2002 was not a particularly "typical" year, and so decided to develop the price comparisons for the full five year period over which the PJM market has operated – 1999 through 2003.

We had hoped and expected that the generation costs in the pre-deregulation period could be determined from State Public Utility Commission orders in the deregulation dockets, and the associated rate unbundling and cost-of-service analyses in those dockets. However, for a variety of reasons including incomplete and inconsistent information, and policy reasons (in the unbundling determinations in setting price-to-beat rates, regulators were not always clear about how their determinations were based upon the underlying costs on the one hand and the policy objective of promoting competition on the other). Because the records provided an insufficient foundation for determining the generation service cost portion of the bundled regulated rates in 1996, we went to the FERC Form 1 cost information in order to perform our own rate unbundling. This also allowed us to have a detailed and consistent set of data on the pre-deregulation GSC for each company, so that we could then do a proper "indexing" of those costs forward in time.

We decided to analyze three companies as "case studies," in order make the analysis a reasonable level of effort. These were selected to represent a range geographically and in terms of price. We analyzed Delmarva Power & Light in Delaware (Delmarva), Jersey Central Power & Light in New Jersey (JCP&L), and Pennsylvania Electric Company (in Pennsylvania (Penelec).

In the remainder of this section of our report we provide some background on retail deregulation in the three states, and then provide a brief overview of the restructuring of the PJM wholesale market.

In Section 2 of this report, we describe the development of our annual wholesale power costs (WPC). Briefly, for each of the three case study service territories, we used PJM market and load data to prepare a load-weighted WPC that included energy, capacity and ancillary services, but excluded transmission and distribution cost. The resulting average WPCs for each of the three companies, for each of the five study years, are presented in Section 2.

In Section 3 of this report we describe the development of the annual generation service costs (GSC) for the base year (1996 or 1997) for each of the three companies. The objective in this step was to approximate a regulated-but-generation-only cost of service rate-making process. We used FERC Form 1 data for this purpose. Then we "indexed" each company's base year GSC effectively projecting the cost of service rate out to the period 1999 to 2003. For this purpose, we assumed that no new generation was built and that any additional energy needed for load was obtained at the PJM market price. FERC Form 1 data for energy disposition was used in the indexing, along with PJM market price data and trending assumptions for items other than purchased power. The base year unbundling and indexing processes and their results are described in Section 3.

In Section 4, we briefly summarize the results and provide some comparisons. We also identify a number of caveats and areas for further research.

1.2 Retail Deregulation in PJM

Prior to restructuring, utilities bundled their generation, transmission, delivery, metering. billing, and any ancillary costs into one rate for each type of customer. All consumers in a given class were charged an all-inclusive price covering all of those aspects of utility service. In the mid-1990's, many states particularly in the Northeast began to restructure retail electricity markets and offer an opportunity for consumers to choose to seek out competitive electricity supply for their homes and businesses. In order for consumers to be able to shop for the deregulated generation service while continuing to receive (and pay for) regulated monopoly services such as transmission and distribution, utilities were required to unbundle their electricity rates into their constituent components, to educate consumers about their bills, and to allow competitive suppliers to offer generation services directly to customers. Generation costs were separated from transmission costs, which were separated from any ancillary costs and any distribution costs necessary to provide electricity to the ultimate customer site.

Specifically, the generation service component of the consumer's bill could now be examined and compared with other offerings. Typically, a price-to-compare was made available to all customers by their utility. Those customers who chose not to switch remained on default service, sometimes referred to as standard offer service (Delaware) or basic generation service (New Jersey). Consumers could choose alternate generation providers, but other costs, including transmission, continued to remain price regulated.

The states making up the PJM Interconnection, L.L.C. (PJM) region were among the most aggressive in offering consumers competitive electricity generation options. Each state adopted specific restructuring acts, and companies complied with them as required. While all utilities unbundled their rates in a similar fashion, mechanically, there were differences reflecting then current ratemaking rules for each utility. In addition, the various regions of the country began reorganizing their wholesale electricity markets pursuant to Orders from the Federal Energy Regulatory Commission (FERC). In our area of study--Pennsylvania, Maryland, and New Jersey--management of the wholesale power markets was handed over to a reorganized independent system operator: PJM.

1.2.1 Delmarva Power & Light

Delaware's Electric Utility Restructuring Act of 1999, HB10, was enacted on March 31, 1999. The law's provisions included a four-year phase-in of retail competition beginning on October 1, 1999 and ending in 2003.

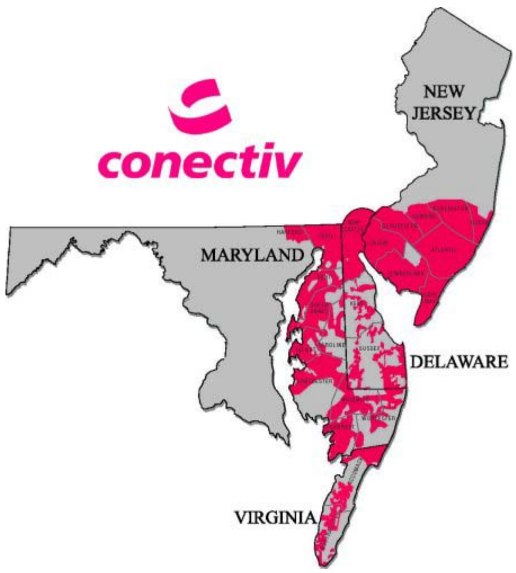

Figure 1.1: Depiction of Delmarva's service territory in Delaware.[1]

Specifically, the Delaware Public Service Commission (PSC) set electricity generation shopping credits for Delmarva Power and Light Company (Delmarva), a subsidiary of Conectiv, that reflected a mandated electricity rate reduction for residential customers. This was reflected in the restructuring spreadsheet, which accompanied the PSC's restructuring plan order. In effect, Delmarva implemented a 7.5% reduction in electric rates for the residential rate class only, effective July 1, 2000. The reduction was apportioned between the unbundled supply rate and the unbundled wires rate. No change in electric rates for the residential rate class was allowed for a 4-year period ending June 30, 2004. In addition, Delmarva residential customers were spared costs associated with stranded cost recovery, while its commercial and industrial customers paid certain stranded cost amounts, via competitive transition charges, over three years commencing in 2000.

Delmarva customers were also given the option to sign competitive electricity contracts as early as April 3, 2000. Despite this theoretical opportunity, there are currently no electric suppliers serving residential customers in Delaware. It appears that due to the

[1] Conectiv website: http://www.conectiv.com/civ/service_territory.cfm.

current regional market prices for electric supply, non-traditional suppliers are unwilling to offer electric service to residential customers. As a result, all residential customers in the Delmarva service territory remain on standard offer service provided by Delmarva. Contrastingly, about a dozen companies are offering competitive electric contracts to both the commercial and industrial sectors in Delaware.

Delmarva service area customers have seen a decrease in their nominal bill rates over the last 10 years. When inflation is accounted for, this translates to real dollar savings.

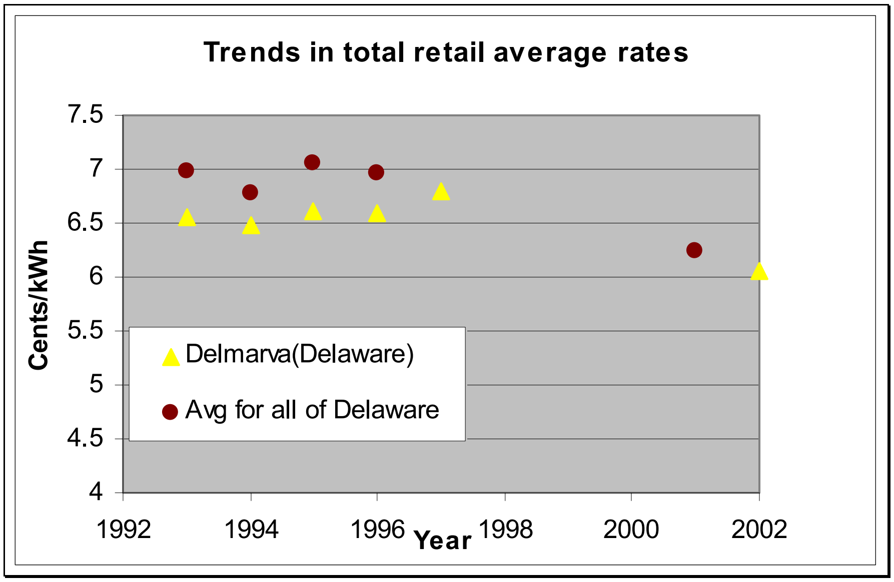

Figure 1.2: Trends in total average electricity rates in Delmarva and the rest of the state. (Nominal dollars)[2]

More recently, non-residential rates have been frozen through September 30, 2002. Delmarva will continue to be the default supplier until May 1, 2006, and effective October 1, 2003, delivery rates will decrease and supply rates will increase, resulting in a net system-wide increase of less than 1%. Conectiv will be entitled to a 1-time opportunity to file for a rate increase to its transmission and ancillary rates on or after Oct. 1, 2003, and before May 1, 2006.

1.2.2 Jersey Central Power & Light

New Jersey customers were given the option to engage in competitive retail purchase of electricity as of August 1, 1999. This was brought about by legislation (New Jersey Bills A 10/S 5), which instituted a four-year transition period and mandated a reduction in then current rates of 5 percent immediately, and over the first 4 years, 10 percent total. In addition, the legislation allowed recovery of each utility's stranded costs through a wires charge paid by consumers.

[2] EEI, *Typical Bills and Average Rates Report.*

Jersey Central Power and Light (JCPL) is an electric company that serves approximately 2.7 million customers over an area of approximately 3,300 square miles. The New Jersey Board of Public Utilities (BPU) approved a restructuring plan for JCPL including shopping credits and recovery of $500 million in stranded costs. In addition to the mandatory 5% rate reduction for New Jersey customers, customers of JCPL also received another 1 percent reduction in 2000, 2 percent in 2001, and 3 percent in 2002. Average shopping credits (actual credits depend on consumer class) were increased to 5.13 cents/kWh for August 1999, 5.27 cents in 2000, 5.31 cents in 2001, 5.36 cents in 2002, and 5.40 cents in 2003. Finally, a rate reduction of 2% occurred in 2001 and by 2003, rate reductions totaling 15 percent were scheduled for all New Jersey customers.

New Jersey electricity customers did show some enthusiasm for retail choice early in the state's retail access program. Approximately 13.5 percent of the power load in the State was supplied by alternative retailers only one year after the start of customer choice.[3] However, customer switching across the state and across customer classes dropped to fractions of a percent and remained there as recently as the summer of 2003. Only two competitive suppliers, FirstEnergy Solutions and Green Mountain Energy, are currently marketing to NJ residential customers. Despite this trend, 63 percent of the largest JCPL customers, or 72% of their large load, continued to buy electricity from alternative suppliers, who are offering a range of options. This is likely the result of these larger customers now having their prices based on PJM's hourly prices, unless they make provisions with a supplier of their choice, since the post-transition period began on August 1, 2003.[4]

Specific switching data for JCPL is listed in Table 1.1 below.

Table 1.1: Switching statistics for JCPL as of July 2003: Percent of Customers Served by Competitive Suppliers by Class. [5]

	Residential	Nonresidential
JCPL	3.7%	4.4%

In December 2001, the BPU authorized an internet auction for its Basic Generation Service (BGS), which serves all customers who chose not to switch to a competitive supplier. Four of the New Jersey's largest electric companies, including JCPL, procured several billion dollars of electric supply to serve BGS load in a single, statewide auction process. The auction commenced on February 4, 2002, and lasted nine days. Fifteen energy suppliers won bids to sell a total of 18,000 MW for one year beginning August 1, 2002. By participating in the auction, these suppliers assumed the BGS capacity obligation for New Jersey customers. JCPL posted closing wholesale prices of 4.87 cents

[3] EIA state statistics.

[4] See, for example, Kenneth Rose, *2003 Performance Review of Electric Power Markets*, www.ksg.harvard.edu/hepg/Papers/Rose.VA.review.elec.mkt.Aug.03.pdf.

[5] Ibid.

per kWh. A second and third competitive supply auction was held in February 2003 and 2004. In 2004, the process was divided into two smaller auctions, one to procure supply for larger customers and the other for smaller customers. A clock auction was followed. In this, in a given round, bidders state how many tranches they wish to serve of a product at the price in that round. The load cap for a product is the maximum number of tranches that a bidder can bid and win for that product. The auction ends when the amount supplied is equal to the amount the electric distribution companies wish to procure. Customers will pay rates based on the final auction prices. (In the first three years of restructuring, customers continued to pay pre-established rates.) Overall, the auction process has been considered highly successful.

Table 1.2: Prices and Winning Suppliers in February 2003 Auction for BGS-FP (smaller) customers. Source: www.bgs-aution.com

Terms and Prices	Winning Bidders (number of 10 month and 34-month tranches won)
JCPL (10 month 5.042 cents /kWh and 34-month 5.587 cents/kWh)	Connectiv Energy Supply (5,5) Constellation Power Source (1,0) First Energy Solutions (0,3) J. Aron & Company (7,0) PPL energy Plus (0,5) Reliant Energy Services (7,0) Select Energy (0,1) Tractebel Energy Marketing (10,0)

How have customers fared overall in terms of their electricity bills? As seen in Figure 1.3 below, rates in New Jersey and those specifically for JCPL have been declining since retail choice began. As it stands, New Jersey customers are paying close to the national average across all rate classes, as shown in Table 1.3.

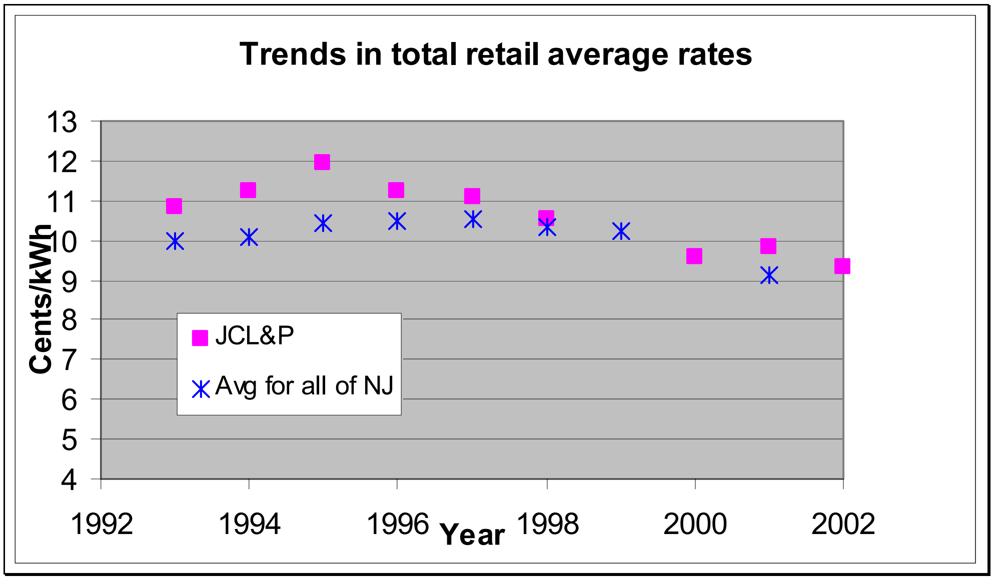

Figure 1.3: Average Retail Electric Rates for NJ customers. (Nominal dollars)

Table 1.3: Generation prices for JCPL vs. the National Average[6]

Electric Energy Classes and Prices	JCPL (cents/kWh)	National Average (cents/kWh)
2002 Residential	5.07	5.02
2002 Industrial	3.85	3.86
2002 Commercial	4.57	5.6

1.2.3 Pennsylvania Electric Company

Pennsylvania became one of the first States to adopt retail electric competition through its Electricity Generation Customer Choice and Competition Act enacted in December, 1996. This Act called for retail access to competitive electricity suppliers for one-third of consumers by January 1, 1999, and for all consumers as of January 1, 2000. In the first week it was available, 1.1 million Pennsylvania consumers signed up for the Electric Choice Program. As part of the restructuring initiative, a rate cap was imposed for all retail customers. In addition residential and commercial customers were to receive an 8 percent rate reduction. However, each utility filed separate testimony to determine its restructured rates.

[6] EEI, *op. cit.*

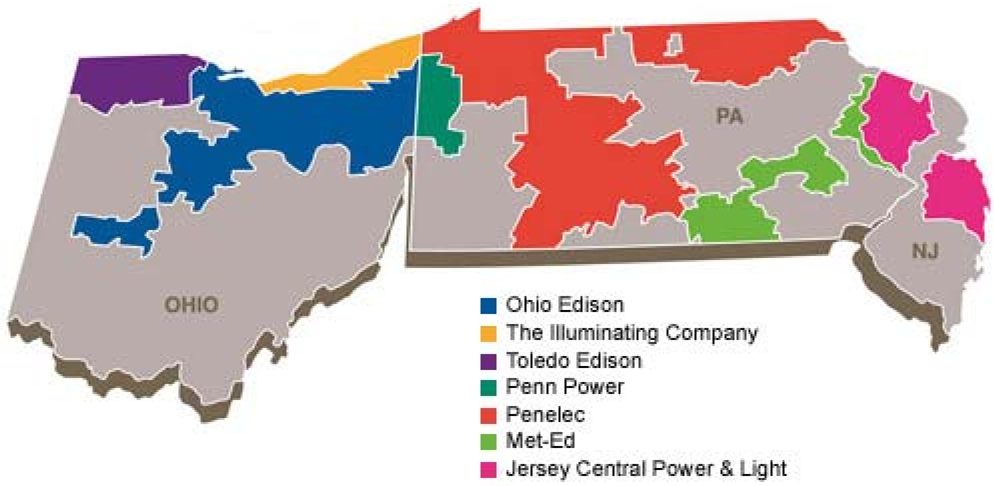

Figure 1.4. The area in red shows Penelec's service area.[7]

Specifically, retail choice for the 1.6 million customers of Pennsylvania Electric Company (Penelec) began on January 1, 1999. Those customers received a 3 percent rate reduction. A cost-of-service and unbundled rate design were used in determining Penelec's restructured rates.[8] Penelec's stranded cost recovery was set at $858 million over 8 years, resulting in an initial price-to-compare for residential electricity generation of 3.73 cents/kWh.

Pennsylvania had at one time the most active retail access program in the country. Initially, 42 % of Penelec customer load switched to a competitive electricity supplier. The greatest switching occurred within the industrial sector, where 76.4% of all load had left default service as of April 1, 1999. But enthusiasm for switching changed dramatically by mid-2001, when many competitive suppliers reduced their offerings or left the market entirely. As of October 1, 2003, the number of customers served by Penelec's competitors decreased to 0.3%, almost all of which came from the industrial class. As it stands, 25.9% of all industrial load in the Penelec service area is supplied by a competitive supplier. Contrastingly, most residential and commercial customers remain on the default offering.[9] In fact, as of December 2003, the entire state of Pennsylvania had only one residential competitive offer below the price-to compare, which was being made by Green Mountain Energy at 6.82 cents/kWh for Green Mountain Environ Blend or 7.56 cents/kWh for Nature's choice.

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[7] www.firstenergycorp.com/cache/_85256A180075DB99_li_Service+Area__file_FEserviceArea.jpg.

[8] Pennsylvania PUC Docket No. R-00974009, prefiled testimony of Malcolm R. Ketchum

[9] PA Office of Consumer Advocate, *Pennsylvania Electric Shopping Statistics*, www.oca.state.pa.us

Table 1.4: Switching statistics for Penelec

	Percent of Customers Served by Competitive Suppliers			
	Residential	Commercial	Industrial	Total
Penelec 2003	0.3	0.1	1.5	0.3
Penelec 1999	3.8	13	28.4	5
	Percent of Customer Load Served by Competitive Suppliers			
	Residential	Commercial	Industrial	Total
Penelec 2003	0.2	1.6	25.9	6.6
Penelec 1999	5.7	50.9	76.4	42.4

Penelec customers will remain in a restructuring transition period through 2008. They have seen relatively stable nominal prices through the 1990's, which translates to decreasing real prices. This has been attributed to both lower coal prices and improved nuclear plant operations; together, coal and nuclear plants account for 95% of Penelec's plants in service in 2002. Currently, Penelec's overall prices remain close to national averages as shown in Table 1.5.

Table 1.5: 2002 Bundled prices for Penelec vs. the National Average[10]

Electric Energy Classes and Prices	Penelec (cents/kWh)	National Average (cents/kWh)
Residential	8.86	8.83
Industrial	4.93	4.89
Commercial	7.54	7.79

More recently, the Pennsylvania Public Utility Commission approved a settlement allowing Penelec to defer its wholesale power losses from the beginning of 2001 through 2005 and carry them on its books through 2010. Any losses remaining at the end of the period can then be written off. As a result, Penelec customers will not receive a rate increase, but shopping credits will rise.

1.3 Wholesale Deregulation in PJM

The PJM Interconnection operates a day-ahead wholesale energy market, a real-time energy market, and a daily capacity market, as well as interval, monthly and multi-monthly capacity markets, a regulation market, a spinning market and a monthly fixed transmission rights auction market. These markets cover transactions within, out of, and into the PJM Region, a geographic area encompassing New Jersey, most of Pennsylvania, Maryland, Delaware, the District of Columbia and portions of Virginia, West Virginia

[10] EEI, *op. cit.*

and Ohio. The PJM markets are highly active, and transactions are sizable, adding up to over $10 billion in 2002, as shown in Table 1.6.

Table 1.6: Approximate 2002 Annual Values of PJM markets[11]

Market	2002 Costs ($ Millions)
Energy	$9,070
Capacity[12]	$1,020
Spinning Reserves	$42
Regulation	$75
Transmission	Not Calculated

The Energy market accounts for about 90% of the total, with the Capacity market accounting for most of the remaining 10%. The Spinning Reserve and Regulation markets are tiny in comparison. We did not calculate the transmission market costs since their effects should be reflected in the locational energy prices.

Over a period of years, PJM has adopted various market designs, as indicted in Table 1.7. Below, we discuss each type of market.

Table 1.7: Various Markets Adopted by PJM.

Market Type	Date Introduced into PJM
Nodal energy pricing with market-clearing prices based on offers at cost	April 1, 1998
Capacity markets	April 1, 1999
Capacity markets broadened to include monthly and multi-monthly markets	Mid-1999
Competitive, auction-based fixed transmission rights	May 1, 1999
Day-ahead energy market	June 1, 2000
Regulation market	June 1, 2000
Modification of regulation market	December 1, 2002
Spinning reserves market	December 1, 2002

1.3.1 Energy Markets

PJM maintains two energy markets: Day-Ahead and Real-Time. In addition to these markets, energy is also traded in bilateral and forward markets, and it can be self-supplied. The PJM markets provide the key benchmark prices for the value of energy.

[11] PJM Market Monitoring Unit, *State of the Market Report*, 2003.

[12] Capacity market value is based on total Obligation at Monthly & Multi-Monthly Market prices.

Throughout PJM, prices vary geographically. In other words, they are locationally-based, using a nodal based pricing mechanism. In this, the entire region is broken down into many small areas or nodal regions. As costs to generate and transmit energy to different nodes vary, so do wholesale prices. The hourly average system-wide price in 2002 was $28.30/MWh, which was 12.6% lower than for the 2001, but close to the values for 1999 and 2000. The wholesale value of the energy use in PJM East in 2002 was approximately $9 billion.

As presented in the PJM State of the Market Report, over half of the marginal units were coal-based, with about one-quarter natural gas and the remaining one-quarter oil. Furthermore, about three-quarters of the marginal units were steam, and the remaining one-quarter were combustion turbines.[13]

1.3.2 Capacity Markets

Each entity that serves PJM load must own or acquire capacity resources to meet regulated capacity obligations. To help meet this need, PJM has several capacity markets in place: daily, interval, monthly and multi-monthly. Again, these markets are in addition to bilateral agreements and self-supply. The largest of the PJM capacity markets are the monthly and multi-monthly markets, which, together, average about 3,000 MW of capacity. Since this represents only about 5% of the total capacity required, it seems that most capacity is sourced outside of these markets. In the PJM markets, the average annual cost of traded capacity is 17.7 $/kW-year. Based on these market prices, the total value of capacity in 2002 was approximately $1 billion.

1.3.3 Spinning Reserve Market

In its Order 888, the United States Federal Energy Regulatory Commission (FERC) defined six ancillary services that must be included in an open access transmission tariff. Of these, PJM currently provides both regulation and spinning through market-based mechanisms. Spinning reserve is defined to be generation that is synchronized to the system and capable of producing output within 10 minutes notice. The spinning reserve market is in addition to that provided by the Tier 1, on-line resources, which provide two-third of the reserves. Throughout the course of a year, the spinning reserve market averages about 250 MW. The average cost for reserves in 2002 was 19.65 $/MW-Hr. This translates into an annual spinning reserve cost of $42 million.

1.3.4 Regulation Market

Regulation resources provide quick response to load and supply variations by moving the output of selected generators up and down via an automatic control signal. The amount of regulation required is based on 1.1% of the peak load level. Market participants can meet regulation requirements through the regulation market, in addition to self-scheduling their own resources or purchasing regulation bilaterally. The regulation market design was modified by PJM effective December 1, 2002, in conjunction with the implementation of

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[13] PJM Market Monitoring Unit, *op. cit.*

the spinning market. The two markets are cleared simultaneously and co-optimized in order to reduce the total cost of ancillary services. The market for regulation permits suppliers to make offers of regulation subject to a bid cap of $100 per MW. These offers plus opportunity costs determine the clearing price. Average regulation costs in 2002 were approximately $25 per MW. This corresponds to a total annual cost of $75 million.

1.3.5 Fixed Transmission Rights Market

PJM also maintains a transmission rights market. To a large extent, transmission costs are reflected in the LMP's. Yet, the transmission rights market does represent costs that are in some way borne by customers. This is a complicated matter, which we do not analyze for this study.

1.3.5 Markets Summary

The PJM market is highly active, and transactions are sizable, adding up to over $10 billion in 2002, as seen in Table 1.8 below.

Table 1.8: 2002 PJM Total Market Costs for Energy, Capacity, and Reserves

Market	2002 Costs ($ Millions)
Energy	$9,000
Capacity	$1,000
Spinning Reserves	$42
Regulation	$75
Total	$10,117

2. PJM Market Operations and Costs

In this section, we develop the wholesale power costs (WPCs) focused on the Energy and Capacity markets, since together, they account for nearly all of the wholesale costs. Below, we calculated the load-weighted generation price for 2002 each of the electric utilities being examined.

Table 2.1: Company Loads and Energy Costs in 2002 [14]

PJM Utility Loads and Energy Prices in 2002				
	Delmarva	**JCPL**	**PenElec**	**Unit**
Average Load	2,157	2,627	1,870	MW
Peak Load	3,758	5,820	2,693	MW
Load Factor	57%	45%	69%	
Real Time Market				
Average Hourly Price	29.9	28.0	29.4	$/MWh
Peak Price	874	702	373	$/MWh
Weighted Average Price	33.4	32.2	31.3	$/MWh

It can be seen from the data in the Table that for 2002 the three companies had similar weighted-average wholesale energy prices. We also examined how this price differed across customer classes, as seen below in Table 2.2. Although we do not have customer class loads for all the companies, such data is available for Delmarva. The equivalent load-weighted prices for Delmarva by customer class show modest variations. As a result, comparing company prices on a total sales basis is reasonable, and this will be our focus for the remainder of this analysis.

Table 2.2: Delmarva Wholesale Energy Costs by Rate Class for 2002 [15]

Rate Code	Rate Class	Average Price
DERS	Residential Service	35.65
DERH	Residential Heating	32.85
DELG	Large General Service	32.91
DEGSP	General Service, Primary	31.82
DEOL	Outdoor Lighting Rate	23.29
DESG	Small General Service	34.15
	Weighted Average	**33.44**

[14] From Synapse computations.

[15] From Synapse computations.

The 2002 Anomaly

In reviewing the PJM State of the Market Report and other material, it appeared that wholesale energy prices in 2002 were unusually low. This was probably the result of the addition of PJM West and relatively low natural gas prices in that year.

The table below shows the equivalent company prices for 2001. While Penelec's energy price is only slightly above its 2002 equivalent, Delmarva and JCPL's are substantially higher.

Table 2.3: Company Loads and Energy Costs in 2001 [16]

	Delmarva	JCPL	Penelec	Units
Average Load	2,045	2,536	1,821	MW
Peak Load	3,553	5,592	2,654	MW
Load Factor	58%	45%	69%	
Real Time Market				
Average Hourly Price	37.0	32.6	30.9	$/MWh
Peak Price	1,024	987	887	$/MWh
Weighted Average Price	41.7	39.1	33.1	$/MWh
Weighted Hourly Premium	12.7%	20.1%	7.0%	

Before settling on a single analysis year we decided to look at the market prices for all the years of PJM operation. Using the total loads for PJM East and the price at the Eastern Hub, we calculated approximate overall weighted prices. This calculation shows that the wholesale energy price in 2002 was anomalously low compared to 2001 and 2003, but comparable to 1999 and 2000.

Table 2.4: PJM East Weighted Energy Costs (Approximate) [17]

Year	$/MWh
1999	34.06
2000	30.72
2001	41.99
2002	32.81
2003	42.64

Subsequently we decided to analyze the PJM markets for all five years of operation.

[16] From Synapse computations.

[17] From "PJM RT [2001,2002,2003] .xls."

Capacity Costs

Capacity markets represent about 10% of total wholesale costs. Although most of the capacity in PJM is traded bilaterally, the monthly and multi-monthly markets operate at an average level of about 3,000 MW, and the price in that market can serve as a proxy for all the capacity resources.

Table 2.5 shows the historical trend of the monthly and multi-monthly capacity markets in PJM. There was a big peak in prices in 2001, with a decline to below historical levels in 2002 and 2003.

Table 2.5: Historic Monthly Capacity Market Activities [18]

PJM Monthly Capacity Markets Sales and Prices					
Year	1999	2000	2001	2002	2003
Capacity (MW)	1,614	1,781	1,841	3,041	3,034
Price ($/MW-Mo)	58.4	46.5	109.0	31.0	18.5

Note: Prices are based on the date of the capacity sale. Actual capacity costs for any actual month represent the mix of the sales in that month and in the previous multi-month sales.

The capacity prices are quite likely related to the reserve margin levels. Table 2.6 shows that reserves were quite low in 2001, but substantially improved in 2002 and 2003. This raises questions about the factors that cause high reserve margins as well as the continued likelihood of this trend in the future.

Table 2.6: Reserve margins for PJM 2001-2003. [19]

	2001	2002	2003
Total Internal Demand (MW)	54,015	54,188	55,089
Net Internal Demand (MW)	54,015	52,569	53,470
Net Operable Capacity (MW)	60,008	63,514	67,678
Net Capacity Resources (MW)	59,533	64,002	68,166
Net Reserve Margin	10.2%	21.7%	27.5%

Although the PJM ISO was started in 1998, its products, services and markets have evolved considerably since that date. Some of the initial markets were established for energy and capacity. More recently, market support charges and black start services have been added. These costs were previously internalized in the regulated vertically-integrated utilities.

[18] From Synapse computations.

[19] From "PJM Monthly Capacity Market.xls" extracted from the annual State of the Market Reports.

Table 2.7 below summarizes the costs associated with the various markets and services in PJM from 1998 through 2003. Note that approximately 90% of the costs are associated with energy use as calculated via the locational market prices (LMP). Capacity obligation costs represent the bulk of the remaining costs, but have varied widely from year to year. Note also that transmission costs are not included in these numbers.

Table 2.7: PJM East Total Market Costs 1998-2003 [20]

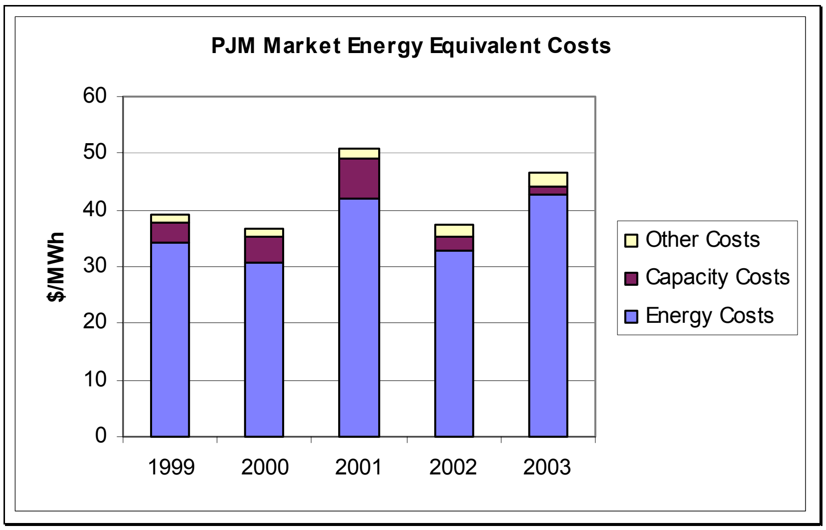
Category	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
Max Load (MW)	48,469	51,714	49,462	54,030	55,934	53,737
Average Load (MW)	28,759	29,640	30,113	30,297	31,563	31,697
Load Factor	59.3%	57.3%	60.9%	56.1%	56.4%	59.0%
Total Energy (GWh)	251,931	259,644	263,787	265,398	276,490	277,662
Load Weighted LMP ($/MWh)	24.16	34.06	30.72	41.99	32.81	42.64
Fuel Cost Adjusted LMP ($/MWh)	58.66	61.40	44.67	48.06	47.11	42.64
Energy Costs (M$)	$6,087	$8,843	$8,104	$11,145	$9,072	$11,840
Capacity Obligation (MW)		51,779	52,697	54,448	57,557	59,630
Weighted Average Price ($/MW-day)	N/A	52.86	60.55	95.34	33.40	17.08
Equivalent Capacity Costs (M$)		$999	$1,165	$1,895	$702	$372
Spinning Credits (M$)		$81.1	$68.7	$34.6	$42.7	$47.1
PJM East Fraction		1.000	1.000	1.000	0.882	0.848
Operating Reserves (M$)		$53.6	$146.8	$251.1	$166.7	$232.2
Reactive Credit (M$)		$67.4	$70.4	$59.0	$59.3	$67.1
Regulation Credit (M$)		$129.2	$119.8	$131.9	$123.4	$139.2
Market Support (cents/MWh)			#N/A	2.24	4.30	8.04
Market Support (M$)		0	0	$5.9	$11.9	$22.3
Transitional Charges (cents/MWh)					52.50	70.00
Transition Charges (M$)	0	0	0	0	$145.2	$194.4
Black Start Services (M$)		0	0	0	$0.4	$4.4

[20] Information provided in private communications with PJM and from the annual State of the Market Reports.

Total PJM Market Costs (M$)	$10,174	$9,674	$13,523	$10,323	$12,918
Energy Allocated Price ($/MWh)	$39.18	$36.67	$50.95	$37.34	$46.53
Non-Energy Cost Component ($/MWh)	$5.12	$5.95	$8.96	$4.53	$3.88

Figure 2.1 below shows the substantial year-to-year variations in energy costs and the even greater relative swings in capacity costs. The reduction in capacity costs appears to be related to the substantial capacity additions that occurred in 2001-2002.

Figure 2.1. PJM Annual Wholesale Market Costs

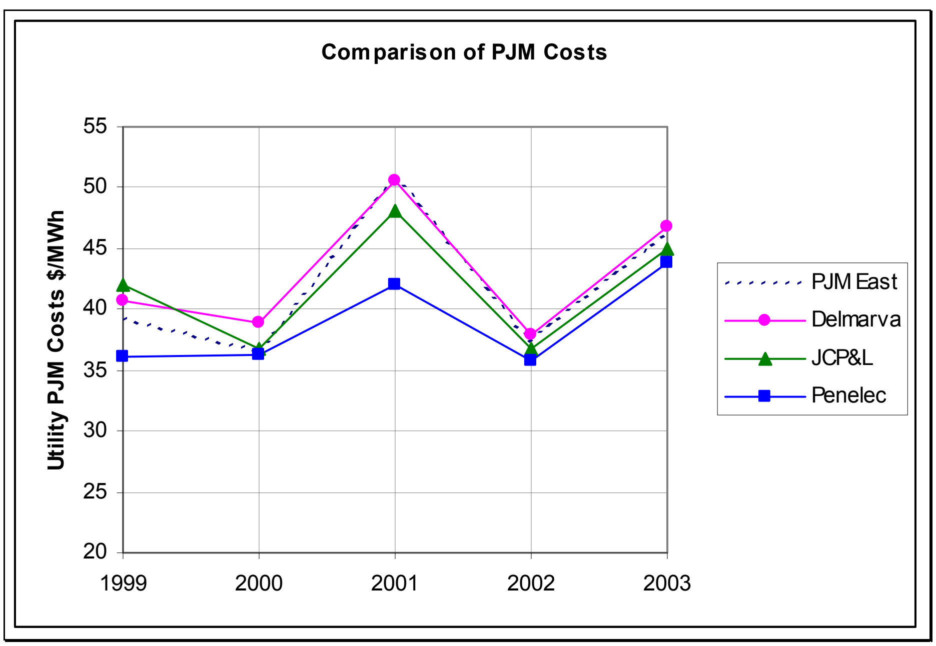


The table and graph below shows the PJM market costs for the studied utilities. Note that Delmarva and JCPL are close to the average for PJM East. Penelec costs are lower especially in the peak year of 2001, yet they were much closer to the average in the most recent higher cost year of 2003.

Table 2.8: PJM Market Costs Summary for Selected Utilities: 1999-2003

	Load-Weighted LMPs ($/MWh)				
	1999	**2000**	**2001**	**2002**	**2003**
PJM East	34.06	30.72	41.99	32.81	42.64
Delmarva	35.52	32.96	41.66	33.44	42.84
JCPL	36.82	30.82	39.15	32.15	41.06
Penelec	31.01	30.24	33.09	31.32	39.87
Other Costs	5.12	5.95	8.96	4.53	3.88
	Full Energy Supply Costs ($/MWh)				
	1999	**2000**	**2001**	**2002**	**2003**
PJM East	39.18	36.67	50.95	37.34	46.53
Delmarva	40.64	38.91	50.62	37.96	46.72
JCPL	41.95	36.77	48.10	36.68	44.94
Penelec	36.14	36.20	42.04	35.84	43.76

Figure 2.2. Utility & PJM Market Cost Comparisons



3. Generation Service Costs

3.1 General Approach

Once we had developed the annual Wholesale Power Costs (WPC) for each of the three service territories based upon actual PJM market data, we continued with preparation of a load-weighted generation service cost (GSC) that included energy, capacity and ancillary services, but excluded transmission and distribution cost for each service territory. Our next step was to develop an unbundled, rate base / rate of return GSC for each of the service territories for the base year before retail or wholesale electricity restructuring. The objective in this step was to approximate a regulated-but-generation-only cost of service rate-making process. We constructed the base year GSC pro forma financials beginning with each company's base year FERC Form 1.[21] Then, we indexed and projected forward each company's base year GSC for years following the base year. For this purpose, we assumed that no new generation was built and that any additional energy needed for load was obtained at the PJM market price. FERC Form 1 data for energy disposition was used in the indexing, along with PJM market price data and trending assumptions for items other than purchased power. This section explains those procedures.

3.2 Generation Portion of Regulated Rates in Base Year

3.2.1 Overview

In order to support the comparison of power supply costs, we have prepared estimates of the base year generation service cost (GSC) for each study company starting with cost of service data for that year. This subsection documents the derivation of those estimates.

The philosophy followed in this task was to simulate traditional rate base / rate of return economic regulation for a hypothetical wholesale generation company inheriting the load and resources of the study company, along with a proportionate share of the capital costs and capital structure of the study company. In order to obtain results most suitable for use in eventual comparison to WPCs, we not only included in the GSC costs associated with power production, but also included the appropriate allocation of portions of general and administrative (G&A) costs, property taxes, payroll taxes, accumulated deferred income tax provisions, deferred investment tax credits, insurance, and common plant. G&A cost allocation omitted customer service and information, sales, and customer accounts expenses.[22]

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[21] The base year for JCPL and Delmarva was 1996. We were unable to reconcile material plant accounts in the 1996 Penelec Form 1, so we used 1997 as the base year for Penelec.

[22] A wholesale generation service company would incur certain *wholesale* customer service, information, sales and account costs, but those should be minimal in comparison to those for a retail company.

Variations in the allocation and estimation methodologies for the study companies were necessary due to their accounting practices. For JCPL and Delmarva, the companies' 1996 FERC Form 1 filings provided the necessary data for our estimates. For Penelec, we based our estimates on data from the Company's 1997 FERC Form 1.

3.2.2 General Methodology

The costs comprising the base year GSC revenue requirement were divided into several broad categories: operating expenses (including fuel, operation and maintenance (O&M) expense, depreciation and amortization expense, as well as taxes other than income taxes), return on rate base, working capital allowance, and adjustments for deferred income taxes and investment tax credits. Sales for resale revenue was then deducted to obtain the final revenue requirement.

Operating expenses included the following items:

- Allocated A&G expense
- Allocated tax expense other than payroll and income taxes
- Allocated payroll tax expense
- Production plant depreciation expense
- Production plant amortization
- Allocated common plant depreciation
- Allocated common plant amortization
- Fossil plant O&M expense
- Fossil plant fuel expense
- Nuclear plant O&M expense
- Nuclear plant fuel expense
- Hydroelectric plant O&M expense
- Purchased power expense

Together, these items yielded a Production Expense, which was then reduced by credits for accumulated deferred income taxes, deferred income tax credits, and resale revenue. To that was added an estimate of return on production rate base, which was calculated by multiplying the rate base by the tax affected weighted-average rate of return. The resulting amount gave a Preliminary Revenue Requirement for generation service.

An estimate of the working capital amount was determined as follows. We added one-eighth of the preliminary revenue requirement to the value of production plant materials and supplies, plus the net nuclear fuel balance to give the amount of working capital. This working capital amount was then multiplied by the tax-affected rate of return to yield a working capital allowance for inclusion in the revenue requirement.

The tax affected rate of return was computed using the actual returns for common equity and the preferred stock dividend rate (both adjusted for pre-tax return using a 35% federal tax rate and the state corporate income tax rate for each company), as well as the rate of interest on long-term debt, which was determined by the existing capital structure of the company.

Accumulated deferred income taxes were estimated using allocated production plant in service balances. The total accumulated deferred tax balance (net) was first allocated based on the fraction of each production plant category represented of total tangible plant in service. A similar allocation was made to the general plant. Thereafter, it was reduced by the ratio of production plant to total plant. That balance was multiplied by the tax-affected rate of return. This resulted in a credit to cost of service.

In summary, the GSC revenue requirement is the sum of:

- Production expense
- Less allocated accumulated deferred income taxes
- Less allocated accumulated deferred income tax credits
- Less sales for resale revenue
- Preliminary return on the above, and
- Working capital allowance

Property taxes, property insurance and deferred investment tax credits were allocated based on the ratio of production plant in service to total plant in service. Payroll taxes and A&G expense (other than taxes and property insurance) were allocated based on the ratio of production plant payroll to total payroll. Common plant rate base (for companies that reported common plant account information), depreciation expense and amortization were allocated based on the ratio of production plant to total plant. Taxes other than payroll, income, and property taxes (typically franchise or gross receipts taxes) were allocated based on the ratio of production revenue to total revenue.

3.2.3 JCPL Variations

JCPL's 1996 FERC Form 1 does not list any common plant, so no allocation was made. In addition, JCPL serves one small municipal electric company in New York in what is essentially a turnkey operation. All costs and sales of that operation are included, but are unlikely to have a material impact on the GSC revenue requirement.

3.2.4 Delmarva Variations

Delmarva is a combined gas and electric utility. Therefore, some accounts required a further allocation between gas and electric business. Where this was required, we used the ratio of electric revenues to total revenues.

Delmarva is a multi-state utility with minor operations outside Delaware. All costs and retail sales were included. In particular, taxes paid in other states were included. This may overstate the revenue requirement to the extent that those operations outside Delaware were not related to retail electric sales.

Delmarva's 1996 FERC Form 1 does not itemize payroll taxes separately. Payroll taxes were assumed to be 10% of payroll expense, approximately the same value as for Penelec. To adjust for this, the total for taxes other than payroll, income, and property taxes was set equal to the total taxes minus income and property taxes. This was then reduced by the estimated payroll taxes.

3.2.5 Penelec Variations

As mentioned above, the Penelec FERC Form 1 for 1996 was internally inconsistent by material amounts. As a consequence, we relied on the Company's 1997 FERC Form 1 in all respects.

3.2.6 Summary

For each study company, we prepared a pro forma cost of service revenue requirement for a hypothetical wholesale generation service company. These pro formas followed traditional rate base / rate of return rate-making, but were limited to production expenses (including return of and on production rate base and allocated common plant rate base) and certain allocated A&G expenses directly relevant to wholesale generation.

3.3 Indexing of GSC Cost

With the exception of Production Cost, the indexing of GSC cost elements from the base year forward relied on base year ratios and certain assumptions that were mainly identical across the study companies, but varied for certain items such as plant additions, that were anomalous in the base year. This subsection reviews those assumptions and methods; Production Cost indexing is described in Sections 3.4 and 3.5.

Net Plant Additions reflect the balance of routine capital additions to existing plant and routine retirements of capital items retired from existing plants due to replacement or obsolescence. Because the base year may have included addition of wholly new capacity or complete retirement of generating capacity, Net Plant Additions was, perhaps, the most complex item to project, aside from Production Cost. The default method was to assume net additions to Utility Plant in Service for generation service at the same annual percentage rate as observed in the base year. That rate was applied to the previous year's end of year Plant in Service balance to calculate the current year's additions. However, the line item detail of the plant account changes for the year and the detailed plant data in the FERC Form 1 were examined for each study company to identify possible anomalies, and several instances of such anomalies were found.

For Delmarva, 1996 Other Production Plant is an example; the average Net Plant Additions rate for the other categories of production plant was used for Other Production Plant in that case.

In the case of JCPL, we identified from FERC Form 1 data a number of specific retirements of capacity and an apparent major unit overhaul. JCPL's Other Production Plant rate of net additions was set to the base year value *after* removing the effect of building a new CT generator. The JCPL base year Hydro Plant accounts appeared to reflect a major overhaul of one or more specific plants; we substituted an assumed 1% figure for hydro Net Plant Additions to reflect a return to routine capital additions at a rate consistent with relatively new plant. Lastly, for JCPL Steam Plant, we adopted the base year Net Plant Additions rate after removing the effect of retirements and transfers due to retirement of five specific plants.

For Penelec (whose base year is 1997), we saw very large additions, retirements, and transfers in the Steam Plant account, notably in the structures sub-account. The Hydro and Other accounts showed very minor activity. We assumed a conservative 1.5% Net Plant Additions rate for Steam, Hydro and Other to reflect routine capital additions.

Production Plant in Service was adjusted annually by the Net Plant Additions for each category of Plant. Total Plant in Service (used for certain allocations, such as Common Plant) was indexed by the rate of change in Production Plant in Service.

Depreciation Accrued in each year was set to the prior year's Production Plant in Service times the base year depreciation rate. Base year depreciation rates were computed from the FERC Form 1 base year depreciation accrued and the Production Plant in Service. Each year, the Depreciation Reserve was also increased by the Depreciation Accrued, and Net Production Plant was set to Production Plant in Service minus the Depreciation Reserve.

Annual Depreciation Expense was set at the current year's Depreciation Accrued. Amortization expense was held constant for those study companies that reported such expense in the base year. Common Plant Depreciation and Amortization were held constant, where reported in the base year.

Production O&M expense, including payroll and property taxes, fuel, and purchased power, as well as revenue from resales, was developed according to the methods described in the next two subsections.

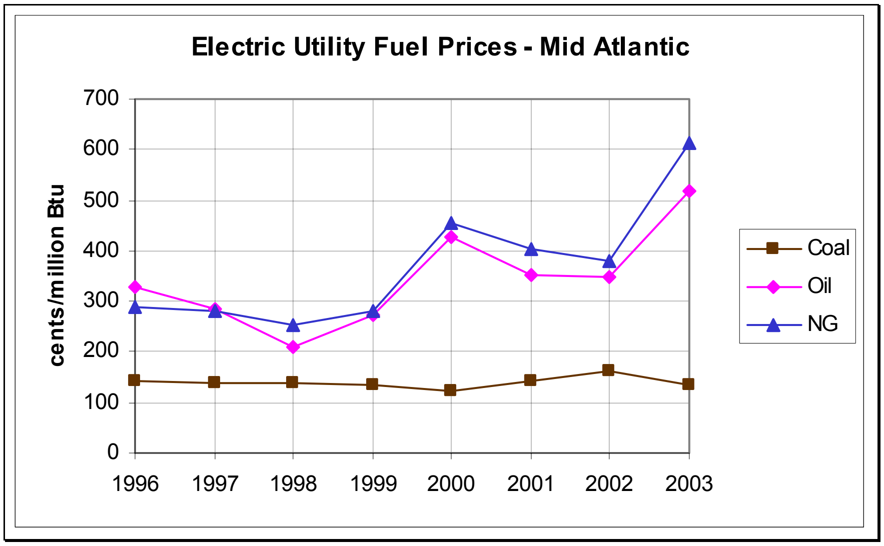
Taxes Other than Income, Payroll and Property were held constant, as were the capital structure, cost of capital, and allocation to current year income and expense of Accumulated Deferred Investment Tax Credits.

Tax-affected return on capital, working capital amount, and return on working capital were computed from the above items using the same methods as in the base year GSC computation. Credit for Accumulated Deferred Income Taxes was computed as in the base year, but the balance of those deferred taxes was indexed based on the ratio of current year Net Production Plant to base year Net Production Plant.

3.4 Indexing of Production Costs

A key component of the GSC analysis is the indexing of the generation production costs, which represent fuel along with operating and maintenance expenses. Our basic methodology for this was to start with the actual generation capacity and costs for a base year before deregulation and then to adjust those values to reflect load growth, sales and purchases, and locational fuel cost indices to project those costs into future years. The graph below shows the average utility fuel prices over this period. While coal prices remained fairly stable, natural gas and oil prices doubled (in nominal dollars) from 1996 to 2003.

Figure 3.1. Utility Fuel Prices



The base year generation and cost data was obtained from the FERC Forms 1 for each company, as were the future load requirements through 2002. Since the FERC data was not available for 2003, we did a simple projection of loads for that year.

The table below summarizes the results of this process for Delmarva. In this case, 1999 was used as the base year. Note that the customer load grows at about 4% a year. The resale levels decline substantially, as do the purchases. Our view is that purchases for resale are financially neutral, i.e. the costs and revenues are essentially in balance. Beyond that, generation increases modestly for existing plants based on their capacity factors. Purchases increase to make up the difference in customer requirements. Generation costs are indexed using the fuel price indices described above. Since Delmarva has substantial nuclear and coal generation, the average cost varies only modestly from year-to-year.

Table 3.1: Indexing of Delmarva Production Costs under Regulation

	1999	2000	2001	2002	2003
Load Requirement (GWh)					
Customer Requirement	12,769	13,589	14,000	14,837	15,573
Resale	9,458	7,681	3,550	634	0
Total Requirement	22,228	21,270	17,550	15,471	15,573
Annual Generation (GWh)	1999	2000	2001	2002	2003
Nuclear	2,521	2,587	2,587	2,587	2,587
Coal Steam	4,117	4,381	4,514	4,784	5,021
Oil Steam	1,546	1,645	1,695	1,797	1,886
NG CC	1,658	1,764	1,818	1,926	2,022
Oil CT	52	56	57	61	64
Purchases	12,333	10,836	6,878	4,316	3,993
Total	22,228	21,270	17,550	15,471	15,573
Production Cost ($1000s)	1999	2000	2001	2002	2003
Nuclear	51,182	52,535	52,535	52,535	52,535
Coal Steam	113,287	113,932	131,014	151,379	138,844
Oil Steam	49,918	75,052	66,094	69,676	100,682
NG CC	52,534	85,515	79,292	79,480	128,595
Oil CT	6,000	8,292	7,566	7,986	10,778
Purchases	653,515	490,379	305,803	188,324	179,704
Total	926,436	825,706	642,305	549,380	611,138
Average Cost ($/MWh)	$41.68	$38.82	$36.60	$35.51	$39.24

3.5 Calculation of Generation Service Costs

The production costs were then included to the indexed GSC values along with various other costs to arrive at the full indexed GSC. Note that with the addition of these other costs, the average GSC cost of energy is greater than the direct production cost by about 10-15 $/MWh depending on the year.

Table 3.2: Delmarva GSC Cost Components

	1999	**2000**	**2001**	**2002**	**2003**
Loads and Sales (MWh)					
Ultimate Consumers (MWh)	12,363,783	13,137,146	13,339,105	14,036,309	14,733,513
Resales (MWh)	9,157,794	7,425,553	3,381,875	600,030	0
Own Use (MWh)	38,828	40,187	38,759	36,409	36,409
Losses (MWh)	667,355	667,209	790,099	798,236	803,523
Total Disposition (MWh)	22,227,760	21,270,095	17,549,838	15,470,984	15,573,445
Cost Summary (1,000 $)					
	1999	2000	2001	2002	2003
Deprec & Taxes	69,301	71,553	73,889	76,311	81,901
Production Costs	272,921	335,326	336,501	361,056	431,434
Purchased Power	653,515	490,379	305,803	188,324	179,704
Other taxes	9,504	9,504	9,504	9,504	9,504
Total Production Expenses	1,005,241	906,763	725,698	635,195	702,543
ROR Effects	79,724	78,887	78,045	77,197	76,343
Resale Income	-402,703	-481,364	-193,784	-33,301	0
Preliminary Revenue Reqt.	682,262	504,286	609,958	679,090	778,886
Return on Working Cap	15,081	12,133	13,819	14,907	16,496
Total GSC	697,343	516,419	623,777	693,997	795,382
GSC Unit Cost ($/MWh)	**56.40**	**39.31**	**46.76**	**49.44**	**53.98**

The table below shows the GSC summary for JCPL. The average GSC costs for this utility are much greater than for Delmarva.

Table 3.3: JCPL GSC Cost Components

	1999	2000	2001	2002	2003
Loads and Sales (MWh)					
Ultimate Consumers (MWh)	18,365,532	18,972,199	19,182,150	19,813,646	20,736,474
Resales (MWh)	1,839,791	1,770,072	2,000,000	2,000,000	2,000,000
Own Use (MWh)	61,344	59,456	65,000	68,842	56,141
Losses (MWh)	1,346,726	1,670,395	1,666,961	1,729,845	1,342,787
Total Disposition (MWh)	21,613,393	22,472,122	22,914,111	23,612,333	24,135,402
Cost Summary (1,000 $)					
	1999	2000	2001	2002	2003
Deprec & Taxes	98,400	100,265	102,196	104,198	104,198
Production Costs	231,992	241,511	256,429	260,800	264,875
Purchased Power	665,071	808,772	814,020	886,372	828,874
Other taxes	67,599	67,599	67,599	67,599	67,599
Total Production Expenses	1,063,061	1,218,147	1,240,244	1,318,969	1,265,546
ROR Effects	65,939	60,713	55,492	50,278	45,274
Resale Revenue Adjustment	-64,262	-74,891	-116,941	-75,114	-116,941
Preliminary Revenue Reqt.	1,064,738	1,203,969	1,178,795	1,294,132	1,193,880
Return on Working Cap	41,271	42,003	39,836	40,151	36,732
Total GSC	1,106,009	1,245,972	1,218,631	1,334,283	1,230,612
GSC Unit Cost ($/MWh)	**60.22**	**65.67**	**63.53**	**67.34**	**59.35**

The table below shows the GSC summary for Penelec. The average costs for this utility are the lowest of the three.

Table 3.4: Penelec GSC Cost Components

	1999	**2000**	**2001**	**2002**	**2003**
Loads and Sales (MWh)					
Ultimate Consumers (MWh)	13,090,993	13,195,866	13,302,316	13,409,625	13,517,799
Resales (MWh)	3,929,785	3,961,267	3,993,222	4,025,435	4,057,908
Own Use (MWh)	38,491	40,283	40,608	40,935	41,265
Losses (MWh)	1,107,947	1,116,919	1,125,929	1,135,012	1,144,168
Total Disposition (MWh)	18,167,216	18,314,335	18,462,075	18,611,007	18,761,140
Cost Summary (1,000 $)					
	1999	2000	2001	2002	2003
Deprec & Taxes	59,406	60,320	61,247	62,189	63,146
Production Costs	246,303	236,471	263,501	287,705	256,840
Purchased Power	257,684	345,779	324,943	316,459	437,344
Other taxes	14,156	14,156	14,156	14,156	14,156
Total Production Expenses	577,549	656,726	663,847	680,510	771,486
ROR Effects	47,196	43,187	39,116	34,983	30,786
Resale Revenue Adjustment	-119,609	-156,146	-154,738	-158,127	-201,926
Preliminary Revenue Reqt.	505,136	543,767	548,224	557,366	600,346
Return on Working Cap	11,713	12,194	12,056	11,998	12,548
Total GSC	516,849	555,962	560,280	569,364	612,894
GSC Unit Cost ($/MWh)	**39.48**	**42.13**	**42.12**	**42.46**	**45.34**

3.6 Effects of Purchases and Sales on GSC Values

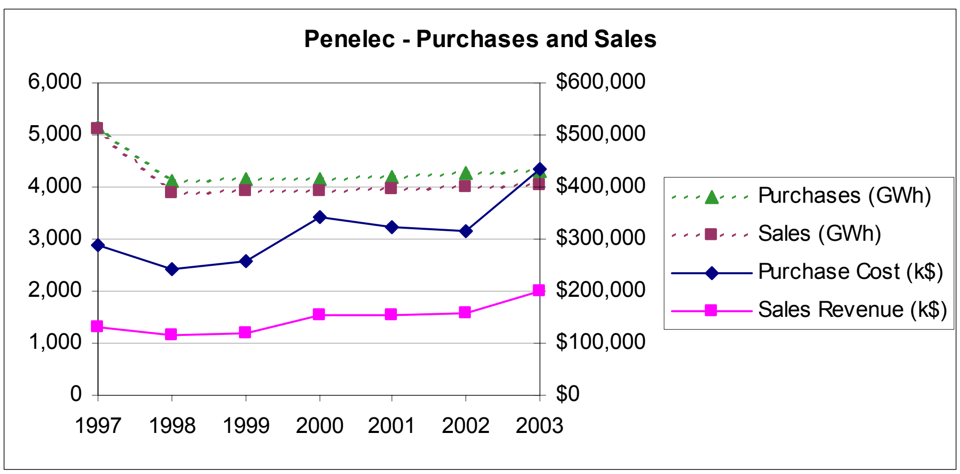
On examination of the GSC tables, it becomes apparent that the net cost of purchased power (after resale revenues) is a significant cost component. For the projection years, we have used the purchase and sales prices as given in the FERC Form 1 reports. Those prices reflect fuel costs and other factors. However, to some degree they also represent the operation of the deregulated PJM market and, thus, may not accurately reflect what would have occurred in the absence of deregulation.

Table 3.5: Net Energy Purchase Costs as a Percent of the Total GSC Cost

	1999	2000	2001	2002	2003
Delmarva	36.0%	1.7%	18.0%	22.3%	22.6%
JCPL	54.3%	58.9%	57.2%	60.8%	57.9%
Penelec	26.7%	34.1%	30.4%	27.8%	38.4%

Of special interest is Penelec where, although the amounts of energy purchased and sold are fairly close, the purchase costs are substantially greater than the sales revenues. This appears to be because the company has a lot of low cost, base load generation and is thus selling economy power during off-peak times while buying power to meet its loads during peak periods. Thus, although the net energy is in rough balance, the relative purchase and sale prices have a significant effect on the final GSC values.

Figure 3.2. Penelec Purchases and Sales



4. Comparison, Analysis, and Conclusions

The table below compares the annual wholesale power costs and the indexed generation service costs for the three study companies. Note that this is not quite an "apples to apples" comparison for several reasons including the presence of "stranded costs" in the indexed GSC, the treatment of transmission in the WPC, the current capacity surplus in PJM, and other factors. These will be discussed below. Nevertheless, it is interesting to observe that the two sets of costs are not too greatly different for Delmarva and Penelec. For some years the WPC and GSC costs are quite close. Occasionally, the GSC is lower. Also note that although the costs are expressed as $/MWh, they incorporate more than purely energy costs. For example in the case of the GSC, costs represent all the ancillary services and capacity values represented by the owned facilities and the power purchases. For the PJM market they represent all ancillary services including capacity as listed in Table 2.7.

Table 4.1: Comparison of GSC and PJM Market Costs ($/MWh)

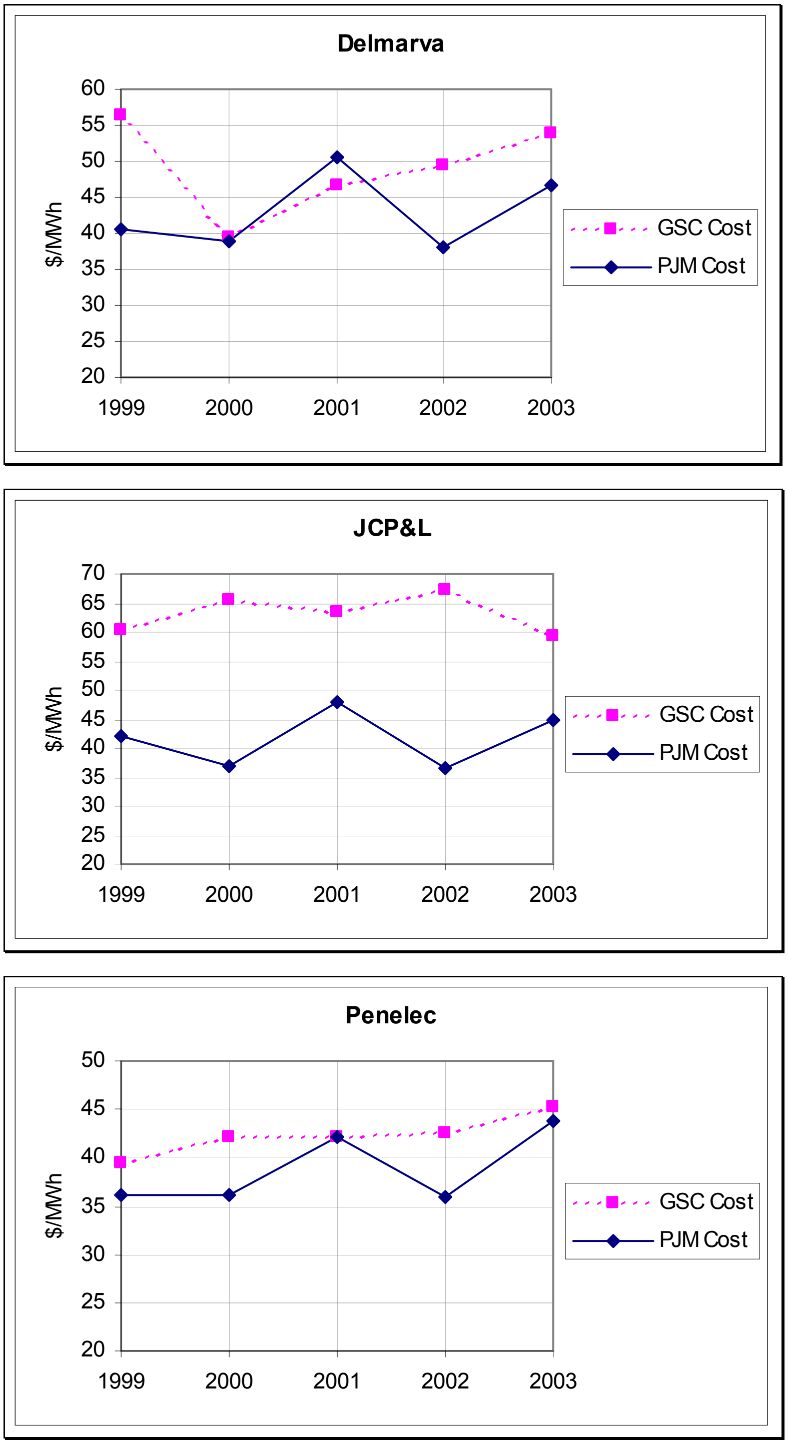
Delmarva					
	1999	2000	2001	2002	2003
PJM Market Supply Costs	40.64	38.91	50.62	37.96	46.72
GSC Cost	56.40	39.31	46.76	49.44	53.98
PJM Market – GSC Costs	-15.76	-0.40	3.86	-11.48	-7.27
Percentage Impact	-28%	-1%	8%	-23%	-13%

JCPL					
	1999	2000	2001	2002	2003
PJM Market Supply Costs	41.95	36.77	48.10	36.68	44.94
GSC Cost	60.22	65.67	63.53	67.34	59.35
PJM Market – GSC Costs	-18.27	-28.90	-15.43	-30.66	-14.41
Percentage Impact	-30%	-44%	-24%	-46%	-24%

Penelec					
	1999	2000	2001	2002	2003
PJM Market Penelec Costs	36.14	36.20	42.04	35.84	43.76
GSC Cost	39.48	42.13	42.12	42.46	45.34
PJM Market – GSC Costs	-3.34	-5.93	-0.08	-6.62	-1.58
Percentage Impact	-8%	-14%	0%	-16%	-3%

The figures below show graphically the relationship between the PJM market costs and the calculated GSC costs for the three utilities. The PJM WPCs show higher volatility than the GSCs, but are at a generally lower price level.

Figure 4.2. PJM Market vs. GSC costs



In conclusion, we find that, while PJM deregulated costs fluctuate year-to-year, on average, the deregulated rates appear to have been lower during this five year period than those generation rates that would have existed under a business as usual, regulated environment. We also conclude that the above approach to this determination is a reasonable means of comparing historical PJM market prices to a traditional, rate-regulated GSC. However, we should also state a set of caveats, which should be kept in mind as one considered these data.

First, with regard to the indexed GSCs, data limitations required the use of highly simplified assumptions about trends in capital costs, taxes, and other factors. It is also important to remember that the indexed GSC costs are conservatively high in a number of ways. Perhaps most importantly, the indexed GSC costs include all the stranded costs that were collected in transition charges and, likely, some that were not. Also, mandated retail rate reductions were not reflected in our indexed GSC costs. And no assumptions were made about productivity improvements in utility-owned generation or overhead operations. Such improvements have been the rule rather than the exception over the past ten years. It is also possible that additional energy for load, under the indexed GSC scenario, could have been obtained through bilateral contracts at prices that were lower than the market clearing price or from utility generation plants that were built with regulated utility financing rather than with entrepreneurial project financing. All of these factors help explain the somewhat high GSC calculation.

Second, the WPCs were calculated without any explicit incorporation of transmission costs. We figured that, to first order, the locational wholesale energy prices that were used would reflect the cost of delivering energy to a particular point on the grid. With the recent auction of transmission rights in PJM, it would be worthwhile to examine the results of the auction and understand what it implies for the comparisons made here.

Third, the WPCs do not necessarily reflect the actual prices that customers are paying at retail. The prices charged by default service (or “standard offer service” or “basic generation service”) suppliers in fact may be significantly higher than the WPCs calculated here, due to factors such as “retail adders” for marketing costs, perceived risks to suppliers, and market power. A comparison of how the prices actually paid by the retail customers for the generation portion of their service compare with the GSCs calculated here would be interesting.

Fourth, the WPCs over the past few years have been lower than were previously expected as a result of capacity surpluses from the addition of new generating plants in the region. If capacity surpluses continue, then the comparative relationships depicted in this report would tend to continue as well. However, to the extent that current capacity surpluses erode sue to demand growth and/or unit retirements, the tighter market will likely produce higher WPCs.

Fifth, we have examined only three case study companies. While we expect that analysis of other companies would show similar results, that conclusion cannot be made without actually conducting the analysis of those other companies.

Each of these five points suggests possible additional research that would be useful in understanding the effects of restructuring in the PJM market. We hope that this current study is helpful in developing the methodologies and illuminating the issues involved in such analysis. We believe that it illustrates some of the economic effects of restructuring in a manner that has not, to our knowledge, been previously attempted. We look forward to comments, refinements, extensions, and question about this work.

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