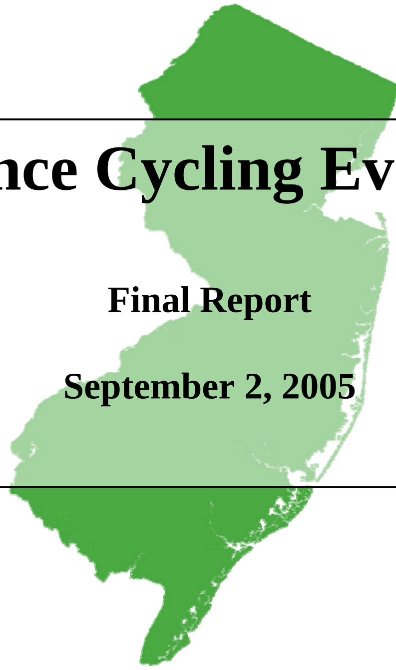

# Appliance Cycling Evaluation

**Final Report**

**September 2, 2005**

CENTER FOR ENERGY,
ECONOMIC & ENVIRONMENTAL POLICY


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## I. Executive Summary

The Clean Energy Appliance Cycling Program (CEACP) cycles primarily residential air conditioners and other appliances during peak summer hours. While the program is operated differently by each utility, it can be used to provide reliability value in the PJM capacity market, to reduce energy costs by shifting demand from high-cost hours to low-cost hours, to improve PJM market efficiency by increasing price-responsive load, support reliability, and to avoid transmission and distribution costs.

The Board of Public Utilities staff (Staff) has expressed an interest in having an analysis of the cost effectiveness of the program and is reviewing the program's structure. The Center for Energy, Economic & Environmental Policy (CEEEP) was engaged by the Office of Clean Energy to conduct this study in response to the Staff's concerns. The analyses and findings of this report are based upon an informational request completed by each of the three utilities that operate the CEACP, PJM market information, publicly available information, and informal discussions among Staff, utility representatives, and CEEEP personnel. CEEEP has prepared this report to provide data and input upon which the Staff can base future decisions.

The CEACP analysis performed by CEEEP is forward looking only. The analysis is based on forecasts of future costs and future benefits. It does not assess the costs or the benefits of the program in the past or the regulatory environment in which the program operated in the past. The results of this study are not indicative of past program performance and should not be used for such purposes.

The program provides a number of benefits that can be readily quantified as well as a number of benefits that are difficult to quantify. The key benefits of the program are as follows:

1. **Capacity Benefits:** The primary quantifiable benefit of the program is the PJM capacity credit. The program will result in BGS providers needing to procure 211 MW less capacity in 2005 than they otherwise would have to if the program did not exist. This benefits BGS customers directly through lower BGS costs.
    a. Forecasts of capacity prices range from a low of approximately $18/MW-day in the high capacity expansion scenario to a high of $154/MW-day in the high capacity requirements scenario. Actual capacity prices will significantly impact the benefits of the program.
2. **Energy Benefits:** The program provides energy benefits by shifting demand from high priced to lower priced hours.
    a. The energy benefits tend to been very volatile depending on PJM market prices. For example, prices exceeded $500/MWh six times in 2001 but did not exceed $200/MWh in 2004. Future energy prices will significantly impact the benefits of the program, particularly if the program is modified to capture fully this benefit.
3. **Transmission and Distribution Benefits:** The program provides reliability benefits and may avoid or delay the need for certain transmission and distribution upgrades. These benefits are difficult to quantify and were not monetized in the cost-benefit analysis. However, regulators should consider the reliability benefits in assessing the value of the program.

   a. While transmission and distribution benefits are difficult to quantify, they are of value. For example, the program was one of the tools utilized by PSE&G as it restored customers after the blackout in the summer of 2003.
4. **Demand Response Benefits:** The program provides needed demand response in the PJM wholesale market. This demand response can be of particular value at times when one or more entity has the ability to exert market power and is of less value in a truly competitive market.
   a. Demand response also lowers prices and transfers value from producers to consumers. This effect is difficult to quantify and may be transitory. However, it may also provide substantial benefits. Although this benefit is difficult to quantify, regulators should consider this benefit in assessing the value of the program.

The environment in which the CEACP operates is changing. PJM is revamping its demand response programs, which may affect the CEACP. In addition, PJM is actively considering major changes to its capacity market, which, if adopted, could increase the value of this program.[1]

The benefits of the program set out above are compared to the costs of the program. One key issue regarding the costs of the program involves whether the payments to customers should be considered a program cost or a transfer payment from all customers to participating customers.

Some believe that traditional cost benefit analyses consider payments to customers a transfer payment that should not be considered a program cost. This belief is incorrect because payments to customers represent a program cost that compensates customers for any real or perceived reductions in comfort level that result from participating in the program. However, in order to assess the impact of excluding payments to customers as a program cost, the cost benefit analysis assessed the program both with and without payments to customers included as a program cost.

Given that certain benefits are difficult to quantify, the cost-benefit analysis understates the total value of the program. That is, a negative cost-benefit amount does not in and of itself demonstrate that the program is not beneficial on a net basis. The additional, difficult to quantify benefits should be considered by regulators in assessing the full value of the program and to inform future program direction. This report also includes several recommendations that may lower the costs and increase the benefits of the program. Regulators should consider not only how the program is currently performing, but also how the program can be changed to operate more effectively.

The analysis compares the expected costs of the program to the expected benefits under various scenarios. In the baseline scenario assuming current program operation, the annual costs exceed the quantifiable benefits, although this difference decreases over time as available

[1] The PJM Interconnection submitted is Reliability Pricing Model proposal to the Federal Energy Regulatory Commission on September 2, 2005.

supplies of capacity in the PJM market tighten. Under some of the capacity price forecasts, however, the net present value of the CEACP is positive.

The current glut in PJM's capacity market results in low short-term capacity prices. Therefore, it is not surprising that the programs costs exceeded the programs benefits in the early years of the analysis and on a net present value overall in the base case. However, other difficult to quantify benefits discussed in the report, as well as the programs value as an option, should be given due consideration by regulators in determining the future of the program.

Given the uncertainty regarding the benefits of the program, the CEACP can be thought of as an option or as an insurance policy, which may have substantial value under some future scenarios. Changes to PJM's demand response programs and capacity markets may increase the benefits and necessitate modifications to the CEACP.

This report includes several recommendations for improving the performance of the program. Predicate to these recommendations is that the BPU needs to provide clear policy direction regarding the goals and operation of this program. Three key recommendations that should be given serious attentionx are:

1. The CEACP is operated differently by each utility. One utility does not obtain PJM capacity credit for its portion of the CEACP whereas the other two utilities do obtain PJM capacity credit. Only one utility operates the program in response to high-energy prices. Consistent and coordinated operation of the CEACP will increase its benefits. Operating the program consistently among utilities including during periods of high-energy prices would result in a positive net present value if the value of the reduction of energy prices, which is a transfer from producers to consumers, were included in the calculation.
    a. This recommendation requires further analysis regarding potential changes to the program that may be necessary for PSE&G and Conectiv to operate the program to capture energy benefits.
2. Conectiv should assess the costs of obtaining PJM capacity credits for its program and compare such costs to the potential benefits quantified in this report.
    a. The utilities should initiate discussions with PJM regarding potential ways to reduce the cost of the evaluations required to verify demand reductions. The three utilities should also explore the potential for performing one coordinated evaluation in 2006, which can reduce the overall cost of the program and reduce the cost to Conectiv of performing the evaluation.
3. Explore the potential for reducing program costs by paying customers when the program is activated as opposed to a fixed payment.

Several other options for restructuring this program are discussed along with their advantages and disadvantages.

With the assistance of Lawrence Berkeley Laboratory, Staff is drafting a multi-year plan for the CEACP. In addition, the Board has authorized PSE&G to conduct a pilot program that would study the benefits of employing new technology in several areas of customer operations and delivery service, providing customers more tools to manage their energy usage.[2] These efforts should contribute to the improvement of the CEACP by enhancing program performance over multiple years and providing useful market research and information.

## II. Introduction

The Clean Energy Appliance Cycling Program (CEACP) cycles primarily residential air conditioners and other appliances during peak summer hours. The program has at least four benefits: 1) it provides reliability value in the PJM capacity market; 2) it reduces energy costs by shifting demand from high-cost hours to low-cost hours; 3) it improves PJM market efficiency by increasing price-responsive load, and 4) it increases T&D reliability and may avoid transmission and distribution costs. It also transfers value from producers to consumers. The Board of Public Utilities staff (Staff) has inquired about the cost effectiveness of the program and is also interested in reviewing the program's structure.

In order to better understand these benefits, the Staff requested that CEEEP perform an analysis of the appliance cycling program that included the following specific goals:

- To estimate the short and long term capacity values (See Section IV.C.);
- To estimate short and long term economic energy benefits including the direct effects from shifting load from high to lower price periods and through market effects resulting from impact on PJM locational marginal prices (See Sections IV.D. and IV.F.);
- To assess the CEACP's impact on reliability (See Section IV.E.);
- To provide options and supporting analysis that can be the basis of Staff recommendations regarding how to maximize the benefits of the program under different scenarios. These scenarios may include continued allocation of benefits to BGS suppliers, selling energy benefits into PJM's economic load response program (if feasible), selling program assets to a third party, using the program to deliver some or all of the capacity, energy, or T&D system support benefits, and determining if additional benefits could be realized if all utilities implemented the program consistently (See Section V.);
- To analyze options regarding whether the program should be maintained, expanded or eliminated including consideration of the conditions under which Conectiv uses the program and exploration with Conectiv the costs, benefits and options for operating their program differently, whether Conectiv and PSE&G would benefit by changing the operation of the program to include cycling for energy purposes, determination of the advantages and disadvantages of expanding the program to RECO's service territory, and determination of the advantages and disadvantages of having water heaters continue to be eligible for the program given their lower net impacts (See Section V.);
- To consider various energy price triggers that should be used to activate the CEACP. (See Section V.G.).[3]

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[2] In the Matter of Public Service Electric and Gas Company's Request for Deferral Accounting Authority for the Energy Information and Control Network Pilot Program, Docket No. EO04060395, August 18, 2004.
[3] This request was not part of the original scope of work but was made by BPU Staff.

The analysis and conclusions of this report are based on an informational request to each utility that has an appliance cycling program, publicly available information (including a public meeting sponsored by the Staff), PJM market information, and informal discussions among utility representatives including a technical review of a draft of this report, Staff, and CEEEP personnel.[4]

Following this introduction this report is organized into four sections. The next section, Section III, reviews the historical performance of the CEACP for each of the three participating utilities (Conectiv, JCP&L, and PSE&G). Section IV presents a cost-benefit analysis, including a detailed forecast of PJM capacity prices – the largest quantifiable benefit of the program. Section V discusses the current structure of the program and whether and how to maximize its future value. Section VI summarizes the report's recommendations.

## III. Appliance Cycling Program Operation

The CEACP primarily cycles residential central air conditioners, although it does include some commercial customers and other devices such as water heaters and heat pumps. It uses a one-way radio signal on utility voice-frequencies from the utility to the customer to activate the program. Each individual utility's program differs in size, by the types of appliances, by the specific incentives offered to customers, and by operating approach. Table 1 summarizes the three utilities' programs. The discussion below elaborates on several important features of the programs described Table 1, including eligibility for PJM capacity value, method of activating the program for energy benefits, and current program status.

Table 1: Summary Comparison of the Appliance Cycling Program[5]

| **Attribute** | **Conectiv Power Delivery** | **Jersey Central Power and Light** | **PSE&G** |
|---|---|---|---|
| *Size of Program as of 2004* | 18,550 customers (all but 532 are residential) | 72,500 customers | 125,302 customers (in 2003) |
| *Types of Customers Enrolled* | Residential and Commercial | Residential | Residential |
| *Types of Appliances* | Air Conditioning, heat pumps, and water heaters triggered by radio-activated relays | Central cooling | Central air conditioners, heat pumps and water heaters |
| *Customer Incentives* | $1.50 per appliance per month and $1.50 per cycle credit | Customers prior to mid-year 1996 receive a fixed bill credit of $24 | Some customers receive $24 per summer season for each control point |

[4] Air Conditioning Cycling Program Meeting, New Jersey Board of Public Utilities, July 29, 2004 that was memorialized in a Discussion Summary and data available on the PJM website, www.pjm.com. Staff also requested that stakeholders submit written comments on the CEACP by August 16, 2004 and then later extended the deadline. Conectiv supplied comments dated September 1, 2004. Staff also held a meeting on October 29, 2004 moderated by personnel from Lawrence Berkeley National Lab that was attended by utilities, PJM staff, CEEEP personnel, and the New Jersey Ratepayer Advocate. The report was submitted to Staff in early 2005 for review. Final reviews were completed in August 2005. The data reviewed and analysis conducted for this study occurred prior to the summer of 2005. Consideration should be given to updating this study's findings based this most recent summer.

[5] Based on companies' responses to data request.

| Attribute | Conectiv Power Delivery | Jersey Central Power and Light | PSE&G |
|---|---|---|---|
| | | After mid-year 1996, customers receive a $200 digital programmable thermostat | whereas others receive a programmable thermostat |
| *Program's Terms and Conditions* | Customers can be cycled year round but are normally are cycled June through September<br><br>Cycles are limited to 4 hours followed by at least 8 hours of non-cycling | Customers may be cycled up to 20 cycling events per year | Customers may not be interrupted more than 15 time per year (10 initiated by PJM and 5 for distribution related reliability) |
| *Amount of PJM Capacity Credit in 2004* | 0 MW | 71.8 MW | 149.8 MW |
| *Trigger Criteria* | Reduce daily peak due to capacity deficiency | Cycling events are based on 1) declaration of a PJM emergency, 2) magnitude of system peak, 3) need for system support, 4) real-time locational marginal prices, and 5) hot weather | Either due to PJM request, system blackout, local transmission and distribution issues, or evaluation study |
| *Recent History of Triggering of Program*<br><br>*(none triggered in 2004)* | Triggered in 1997 on 7 different days for a combined reduction of 25 MW of load. Not triggered in 1995-1996 and 1998-2003. | Triggered 8 times in 2003 and 19 times in 2002 | Triggered twice in 2003 due to the August 14-15 blackout and twice in 2002 |
| *Total Cost of Program in 2003* | $281,000 | $1,588,538 | $4,032.639 |
| *Program Status* | Maintenance Mode:<br>No new customers have been permitted to join prior to the beginning of 1995 and no future plans for marketing the program exist | "Due to uncertainty relative to regulatory support for load control programs, new participants have not been enrolled since the second quarter of 2002"[6] | The program was closed to new participants in late 1999; PSE&G has committed to operate the program with existing participants and will add new customers only to the extent that it is necessary to maintain the current level of system peak demand relief. |

A critical difference among the programs is their operating approach. Conectiv's program does not participate in PJM's Active Load Management Program (ALM) and therefore does not qualify as capacity in the PJM capacity market, whereas the other two utilities do. To qualify for PJM's ALM program, utilities must conduct a study every five years to quantify the load

[6] See JCP&L's response to Question 18.

reduction benefit of the program and activate cycling in response to PJM-declared emergency events up to ten times per year. Conectiv has decided not to meet all the requirements necessary of ALM programs stating that their "program has not been 'turned-over' to PJM with its specific operational criteria, as that would require program design modifications, customer acceptance, and verification."[7] Conectiv also noted that the costs of qualifying for PJM's ALM program may exceed the benefits.

Conectiv and PSE&G do not use the CEACP to reduce customers' energy costs, whereas JCP&L triggers the program when locational marginal prices exceed approximately $200/MWh.[8] This operational difference is reflected in the number of times the program is triggered. For instance in 2002, JCP&L activated the program 19 times whereas PSE&G triggered it only twice and Conectiv not once.[9] None of the utilities activated the program during the summer of 2004.

All three utilities characterize the program as having been in a *maintenance mode* for several years. Although the program is not open to new participants, expenditures are being made to replace missing or inoperable switches for existing participants. For instance, PSE&G closed the program to new participants in late 1999 but added new switches to maintain the program's peak demand relief. JCP&L has not enrolled new customers since the second quarter of 2002, and Conectiv has not permitted new customers since prior to 1995. Over time, more and more switches are likely to fail due to aging, which would require replacement if the current program participation levels are to be maintained. Replacing switches costs about the same as installing new ones.

According to one utility representative, missing or inoperable switches are typically identified during periodic on-site inspections when an attempt is made to cycle the appliance and the appliance does not cycle. Therefore, if a utility were not routinely conducting tests, then missing and inoperable switches would not be identified.

## IV. Cost-Benefit Analysis of the CEACP

This section conducts a cost-benefit analysis of the existing CEACP structure and operation. Section V extends this analysis in its discussion of various program options. The terms *activation* and *trigger* are used below to refer to the cycling of the appliances by the utilities.

For years 2003 and 2004, dollar values reported are in actual year's dollars. For years 2005 and later, dollar values reported are in constant 2004 dollars.

### A. Program Costs

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[7] Conectiv's response to data request Question 5.
[8] JCP&L statement at the BPU's July 29, 2004 meeting. JCP&L resets the price trigger annually depending on market conditions
[9] See the responses to Question 10 of the data request for a complete listing of the dates, times, number of customers, and reason for activation by utility.

Conducting a complete cost-benefit analysis of the CEACP requires quantifying all of its costs and benefits. The cost side of our analyses is relatively straightforward. The programs' actual costs are reported to the BPU annually.[10] For future years 2005 through 2009, the utilities provided forecasts of future program costs in response to the data request.[11] Table 2 provides these costs by year and utility. This analysis did not conduct an audit of the program's costs and used the costs as reported.

The utilities stated that traditional cost benefit analyses consider payments to customers a transfer payment that should not be considered a program cost. This belief is incorrect because payments to customers represent a program cost that compensates customers for any real or perceived reductions in comfort level that result from participating in the program. The cost benefit analysis performed below, however, assesses the program both with and without payments to customers included as a program cost.

Table 2: Annual Costs of the CEACP by Utility (in Thousands of Dollars)

| **Utility** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** |
|---|---|---|---|---|---|---|---|
| Conectiv[12] | $281 | $281 | $281 | $281 | $281 | $281 | $281 |
| JCP&L | $1,589 | $1,601 | $1,727 | $1,654 | $1,568 | $1,432 | $1,396 |
| PSE&G[13] | $4,033 | $4,609 | $5,185 | $5,390 | $5,291 | $5,355 | $5,416 |
| TOTAL | $5,902 | $6,491 | $7,193 | $7,325 | $7,140 | $7,068 | $7,093 |

### B. Capacity Benefits

In PJM, load-serving entities must procure sufficient capacity throughout the year to meet reliability requirements maintained by the PJM Interconnection. These requirements are intended to ensure that sufficient capacity is available in the region to reliably serve load.[14] Parties selling capacity are obliged to make that capacity available within PJM whenever it is available and to coordinate maintenance and other planned outages with the PJM Interconnection. In the capacity market, participants trade capacity bilaterally and through PJM administered auctions. Demand response programs benefit electric customers by reducing the amount of capacity that must be procured on their behalf in order to meet reliability requirements. Programs qualifying for these reductions include the Appliance Cycling Program (except for Conectiv's program, as discussed above) as well as other demand-side initiatives that can be used to reduce load during capacity shortages and to improve system reliability. Reductions to capacity requirements are made as

[10] New Jersey Clean Energy Program Report, June 3, 2004 (Reporting Period: Year-to-Date through Fourth Quarter 2003).
[11] See Question 2 and associated e-mail correspondence with the utilities.
[12] Conectiv did not provide specific forecasts of future program costs but stated that in its response to Question 2: "Until program modifications are made, future program costs are projected to remain similar to 2003." Conectiv's 2003 costs were assumed to be the future program's annual costs with no inflationary increase.
[13] PSE&G provided year-to-date costs for the year 2004 and not estimated annual costs; annual costs for year 2004 are assumed to be the average of 2003 and 2005's annual costs.
[14] More specifically, capacity obligations in the market are set based on a standard that the pool should have no more than a one day in ten year probability that its available resources will prove inadequate to serve load, forcing the pool to resort to involuntary load-shedding or otherwise producing widespread disruptions in electric service.

credits for “Active Load Management” (ALM) and directly reduce the cost of electric service to consumers.

Of the four types of benefits provided by the CEACP, the easiest one to quantify is capacity benefits. For the programs that participate in PJM’s ALM, the quantity of capacity is determined by PJM. Table 3 provides the actual and forecasted capacity benefits in Megawatts (MW) of the CEACP.[15]

Table 3: PJM Capacity Benefit in Megawatts of the CEAP by Utility

| Utility | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|
| Conectiv[16] | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| JCP&L | 62.0 | 60.9 | 59.7 | 58.5 | 57.3 |
| PSE&G[17] | 149.7 | 149.7 | 175.0 | 175.0 | 175.0 |
| TOTAL | 211.7 | 210.6 | 234.7 | 235.5 | 232.3 |

PJM’s capacity market provides a transparent indication of the monetary value of the capacity presented in Table 3. In order to convert these capacity benefits from MW to dollars, a forecast of PJM’s capacity price is required. The next section provides this analysis.

### C. PJM Capacity Price Forecast

Prices in the capacity market provide an important measure of the value demand-side programs. To forecast the price of capacity, an analysis of the relationship between historical levels of capacity supply and historical capacity prices was conducted. After presenting the basis for the forecast, this section discusses several forecasting scenarios included in the analysis. This section concludes with a discussion of some proposed PJM reforms regarding its capacity market and their likely impact on the capacity value realized by the CEACP.

1. Data Utilized and Methodology

a. Overview

This analysis examined the PJM market beginning in June 1999 when the capacity product was redefined consistent with its current form.[18] The data utilized is complete through August 2004. The analysis conducted included market data from both the PJM Mid-Atlantic

[15] See responses to Questions 3 and 16.
[16] According to Conectiv in response to Question 3, in 1997 demand-side management was used and 25 MW of load was reduced.
[17] In year 2007, the amount of capacity benefit for PSE&G increases from 128.3 MW from the previous year to 149.7 MW. PSE&G did not provide a reason for this increase in its response to Question 3.
[18] Specifically, in June 1999, the PJM market began trading “unforced capacity.” Unforced capacity is capacity adjusted to account for historical rates of forced outage. For example, a 100 MW unit with a forced outage rate of 10 percent over the previous year would be eligible to sell 90 MW of “unforced” capacity.

Region and the PJM Western Region[19] when it was added to the market in June of 2003. Except where otherwise stated, all data utilized in this analysis is available at the website of the PJM Interconnection.

Historical data was used to estimate the relationship between capacity margins (CM) (excess capacity above forecasted requirements) and capacity prices using standard regression techniques. The resulting mathematical relationship was then used to project capacity prices based on differing assumptions of the levels of available capacity for the period September 2004 through December 2010. Additions of capacity assumed for the forecast period were estimated based on the interconnection "queue" of generation projects maintained by the PJM Interconnection. Assumptions for the baseline case were consistent with the PJM Interconnection's own projections for future reserve margins. Sensitivity cases varied by changing assumptions about the portion of projects in the interconnection queue that would be completed, the levels of retirement among existing capacity, and the amount of capacity imported from neighboring regions.

b. Historical Price Data

Historical capacity prices utilized in the analyses included the results of all capacity auctions administered by the PJM Interconnection. In PJM, capacity for any given period is sold through auctions that vary by the length of the period over which capacity is provided. These include auctions for daily capacity, monthly capacity, as well as capacity "strips" for multiple month periods. Capacity prices for each month were calculated based on the volume-weighted average of prices for auctions that included capacity for the month in question.

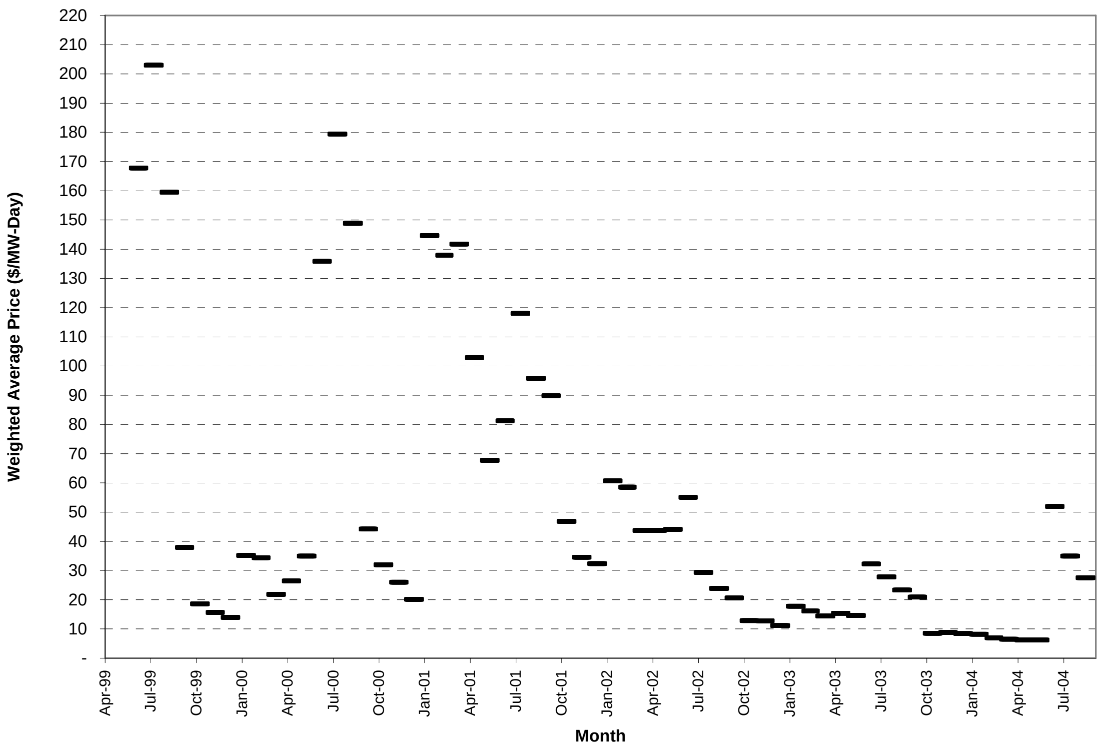
While a great deal more capacity is traded through bilateral transactions between market participants than in the PJM auctions, the prices for such trades are likely to be highly correlated with PJM auction results. Specifically, bilateral trade prices are driven by expectations for prices held by traders. The fact that bilateral trade and PJM auction prices are highly correlated follows logically from the fact that participants are unlikely to trade bilaterally when the prices from available deals stray significantly from these expectations. For this reason, and because reliable data on bilateral trade prices are not widely available, prices for bilateral trades were not included in this analysis.

Figure 1 shows weighted average auction prices for the period studied.[20] While these data show monthly values, daily auction results are included in the average values for each month. As the figure shows, prices tend to decrease over the study period as reserve margins have increased in the region over the period studied. Month-to-month variations in price are substantial. Monthly variations result from fluctuations in import/export levels, bidding behavior, increases in the requirement at the beginning of each planning year, significant additions of capacity, as well as other factors.

[19] The PJM Western Region includes portions of Maryland, Ohio, Western Pennsylvania, Virginia, and West Virginia.

[20] In early 2001, the PJM Market Monitoring Unit concluded that there was market power in the PJM capacity market. The resulting higher prices were not changed by PJM.

Figure 1: Volume Weighted Average PJM Capacity Auction Prices
(PJM Interconnect, June 1999 – August 2004)




### c. Capacity data

Levels of existing capacity are based on a monthly summary available at the PJM website.[21] These data were supplemented with data from the Energy Information Administration (Form 860) in order to complete data for 1999. Assumptions regarding future additions of capacity were estimated based on the interconnection "queue" of proposed capacity additions that was current as of August 2004.[22] Queue data contained projects planned through 2008. In the baseline case, capacity assumptions for years 2009 and 2010 were set equal to 2008 levels. (The assumptions for sensitivity cases are discussed in more detail in the "Results" section below.)

In order to calculate a reasonable estimate of the amount of capacity likely to be added in each year, capacity for projects in the queue were multiplied by a factor between zero and one intended to reflect the likelihood that they would be completed. The factors assigned varied with project status. (e.g., projects "under study" were weighted less heavily than projects "under construction.") Weights were adjusted for the baseline case in order to obtain a reserve margin consistent with PJM's own forecasts over the 2004 – 2008 period.[23] Finally, projects listed in the

[21] See "bom-installed-capacity.pdf" available at: http://www.pjm.com/planning/res-adequacy/resource-reports.html.
[22] Available at: http://www.pjm.com/planning/project-queues/queues.html.
[23] Forecast current as of August 2004 and available at: http://www.pjm.com/planning/res-adequacy/resource-reports.html.

queue as “energy only” were ignored as current rules preclude such resources from participating in the PJM capacity market.

To obtain the most complete possible picture of the supply of capacity likely to be available over the forecast period, capacity retirements and capacity imports and exports were also considered. In the baseline case, 600 MW of capacity were assumed to retire spread evenly throughout the 2005-06 period. Such levels of retirement are consistent with recent retirement activity and the relatively low capacity prices currently available in the pool. Finally, historical levels of capacity imports and exports were estimated for each month based on data available in the PJM State of the Markets Reports. Imports and exports proved to be a significant factor in explaining historical prices. In particular, PJM went from being a net exporter of capacity in 2000 to importing significant capacity in 2003. This swing affected overall capacity levels significantly and had a prominent influence on price. In the baseline case forecast, capacity imports are assumed to drop only slightly from 2003 levels and vary by month (e.g., summer v. winter) in a manner based on recent patterns.

### 2. Market Requirements and Other Parameters

In forecasting capacity prices, it is important to keep in mind that demand in the capacity market is administratively determined and that other administratively determined or calculated factors affect the balance of supply and demand in the market. For example, PJM sets capacity requirements based on a load forecast, required reserve margin, and calculation of the 5-year historical average forced outage rate (i.e., the fraction of time, when called a resource would fail to respond due to an unscheduled outage, denoted here as $EFOR_d$). In addition, requirements are further adjusted to account for load management programs. Table 4 recreates these calculations for the period studied based on information provided on the PJM website.[24] Assumptions for these parameters to be used in the forecast period are also shown. For example, the “Summer Peak Entity Load Forecast” for planning periods beginning in June 2005 is based on the 2004 PJM Load Forecast Report.[25] Other parameters utilized for the forecast period are based on the most recently used values.

[24] Available at: http://www.pjm.com/markets/capacity-credit/parameters.html.
[25] Available at: http://www.pjm.com/planning/res-adequacy/load-forecast.html. Values are scaled from current Planning Year based on projected load growth.

Table 4: Unforced Capacity Requirement and Associated Parameters (6/99 through Forecast Period, Mid-Atlantic Region Only through 5/03, Includes PJM West Thereafter)

| Planning Period[1] | Summer Peak Entity Load Forecast[2] | Reserve Margin[3] | Pool Wide 5-Year Average EFORd[3] | Unadjusted Capacity Obligation | Adjusted Load Management (ALM)[2,4] | ALM Factor[3] | "Effective" ALM | Net Unforced Capacity Obligation[3] |
|---|---|---|---|---|---|---|---|---|
| 6/1/99 - 12/31/99[5] | 49,520 | 20.0% | 9.52% | 53,766 | 1,686 | 0.967 | 1,630 | 51,996 |
| 1/1/00 - 4/30/00 | 50,510 | 20.0% | 9.52% | 54,842 | 1,686 | 0.967 | 1,630 | 53,072 |
| 5/1/00 - 12/31/00 | 50,510 | 19.5% | 9.76% | 54,468 | 1,686 | 0.987 | 1,664 | 52,674 |
| 1/1/01 - 4/30/01 | 52,350 | 19.5% | 9.76% | 56,453 | 1,686 | 0.987 | 1,664 | 54,658 |
| 5/1/01 - 12/31/02 | 52,384 | 19.0% | 9.52% | 56,403 | 1,700 | 0.965 | 1,641 | 54,637 |
| 1/1/03 - 5/31/03 | 55,970 | 19.0% | 8.43% | 60,990 | 1,292 | 0.966 | 1,248 | 59,630 |
| 6/1/03 - 5/31/04 | 65,337 | 17.0% | 6.41% | 71,544 | 1,273 | 0.950 | 1,209 | 70,220 |
| 6/1/04 - 5/31/05 | 66,027 | 16.0% | 5.93% | 72,049 | 1,100 | 0.952 | 1,047 | 70,907 |
| 6/1/05 - 5/31/06 | 67,321 | 16.0% | 6.00% | 73,407 | 1,072 | 0.952 | 1,021 | 72,294 |
| 6/1/06 - 5/31/07 | 68,512 | 16.0% | 6.00% | 74,705 | 1,072 | 0.952 | 1,021 | 73,593 |
| 6/1/07 - 5/31/08 | 69,659 | 16.0% | 6.00% | 75,956 | 1,072 | 0.952 | 1,021 | 74,844 |
| 6/1/08 - 5/31/09 | 70,822 | 16.0% | 6.00% | 77,224 | 1,072 | 0.952 | 1,021 | 76,111 |
| 6/1/09 - 5/31/10 | 71,916 | 16.0% | 6.00% | 78,417 | 1,072 | 0.952 | 1,021 | 77,304 |
| 6/1/10 - 5/31/11 | 73,093 | 16.0% | 6.00% | 79,701 | 1,072 | 0.952 | 1,021 | 78,588 |

1 - Length of Planning Period Varies Over Period Studied.
2 - Historical Information from UCAP "Parameters" Sheets. Future Years Based on 2004 Load Forecast Report
3 - Historical Information from UCAP "Parameters" Sheets. Future Years Based on 2004 Data.
4 - ALM Values Before 4/30/00 are Estimated
5 - Summer 1999 UCAP Parameters are Estimated

For each planning period for which capacity requirements are set, the "Unadjusted Capacity Obligation" is calculated by scaling up the "Summer Peak Entity Load Forecast" by the "Reserve Margin" and scaling it down by the "Pool Wide 5-Year Average EFORd." Relatively large changes in both these percentage adjustments have had a significant impact on the market requirements over the historical period studied. The unadjusted obligation is converted into a final "Net Unforced Capacity Obligation" by accounting for "Active Load Management" Credits. The actual amount of capacity credited is adjusted slightly downward (by the "ALM Factor") to reflect PJM's assessment of the reliability of ALM resources in reducing capacity requirements.[26]

In addition to administrative procedures affecting the demand for capacity, individual resources supplying capacity are subject to an adjustment based on their one-year average forced outage rate. The average factors that capacity resources capacity ratings are reduced are shown Table 5. One-year averages have not varied a great deal since June 1999, but appear to be significantly lower than in years immediately prior to 1999, as seen in the rapid decrease in 5-year averages shown in Table 1. Future year values are estimated based on the average of these more recent values.

[26] This factor should be taken into account in forecasting the value of ALM resources.

Table 5: Pool-Wide Average Forced Outage Rate Adjustments to Capacity Resources (6/99 through Forecast Period)

| Planning Period[1] | Pool Wide 1-Year Average EFORd[5] |
|---|---|
| 6/1/99 - 12/31/99[3] | 6.4% |
| 1/1/00 - 4/30/00 | 6.4% |
| 5/1/00 - 12/31/00 | 6.0% |
| 1/1/01 - 4/30/01 | 5.8% |
| 5/1/01 - 12/31/02 | 5.2% |
| 1/1/03 - 5/31/03 | 5.4% |
| 6/1/03 - 5/31/04 | 6.5% |
| 6/1/04 - 5/31/05 | 6.3% |
| 6/1/05 - 5/31/06 | 6.0% |
| 6/1/06 - 5/31/07 | 6.0% |
| 6/1/07 - 5/31/08 | 6.0% |
| 6/1/08 - 5/31/09 | 6.0% |
| 6/1/09 - 5/31/10 | 6.0% |
| 6/1/10 - 5/31/11 | 6.0% |

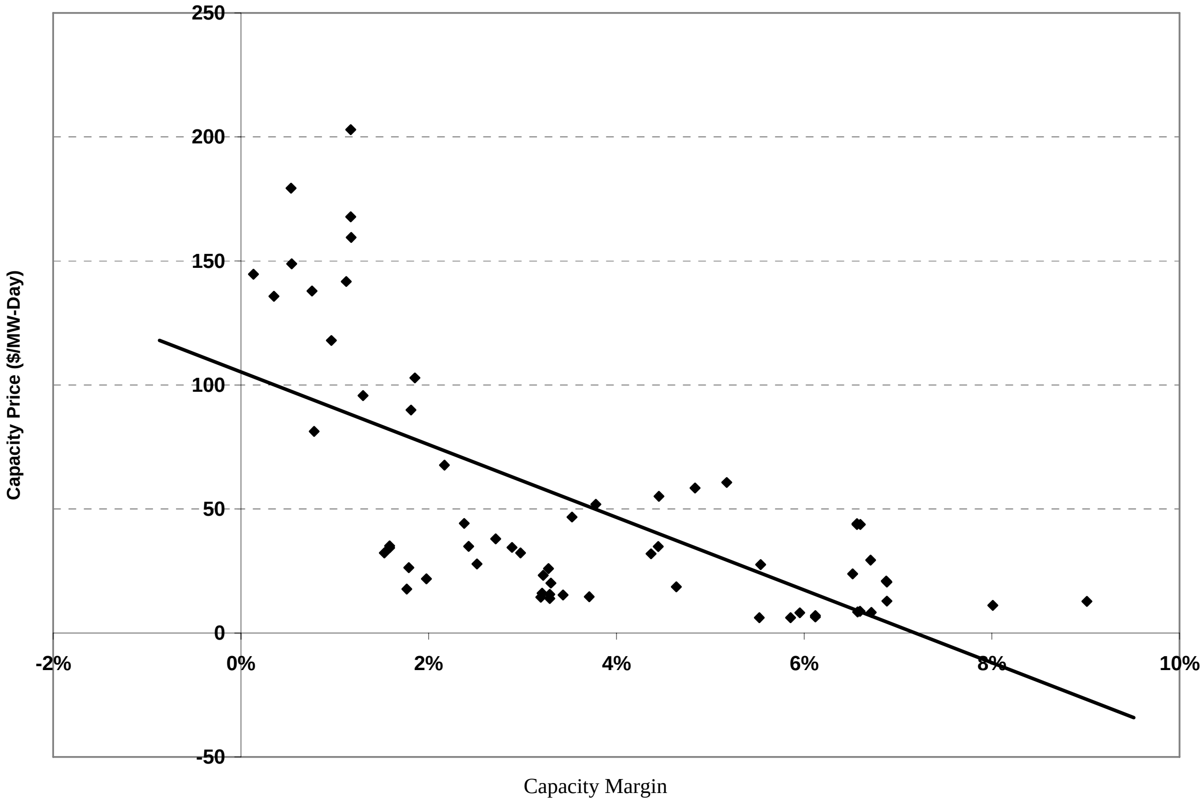
1 - Length of Planning Period Varies Over Period Studied.
2 - Values from PJM MMU 2003 State of the Markets Report. Effect of 12 Month Rolling Average is Estimated.
3 - Summer 1999 Value is Estimated

### 3. Estimation of Forecast Equation

Using the historical data discussed above, a linear regression equation relating capacity reserve levels to capacity prices is computed. A linear approach was used initially for simplicity. To do so, the CM, the excess capacity above the PJM capacity requirement) is calculated for each month by dividing the total amount of capacity available, including both imports and the adjustment for forced outages, by the applicable Net Unforced Capacity Obligation and subtracting one from this value. A positive CM reflects that there is more available capacity than required by PJM; a zero CM indicates that PJM has just enough capacity to satisfy its reliability needs. (This value is then expressed as a percentage.) A standard linear regression relating CM to capacity price produced. These data and the resulting regression line are shown in Figure 2.[27]

[27] The correlation coefficient is -0.659 ($R^2 = 0.4337$), which indicates that capacity prices are inversely related to CM. The resulting regression equation is: $y = -1465.1x + 105.24$.

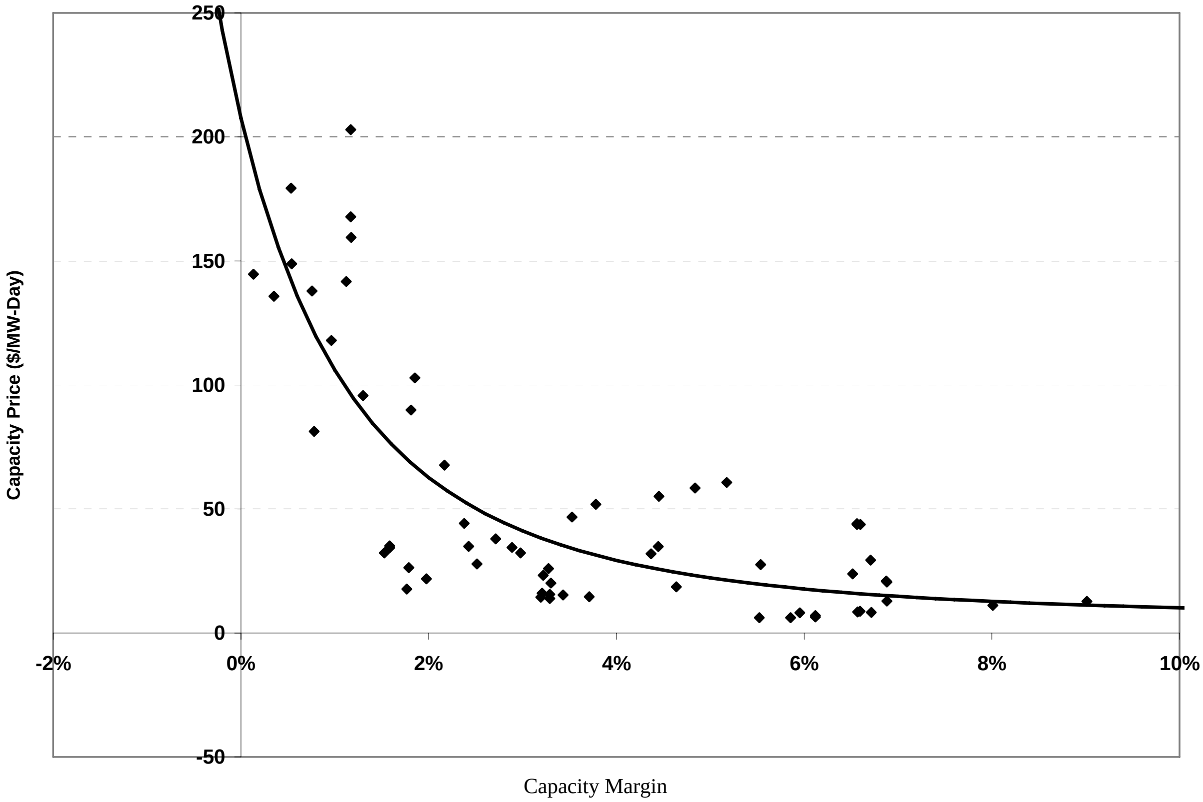
Figure 2: Relationship Between Capacity Margin and Capacity Price Using Linear Regression (PJM Interconnect, June 1999 – August 2004)




While this linear relationship matches the expectation that capacity prices should be negatively related to CM (i.e., that prices go down as reserve margins increase), it also has a number of undesirable properties. Most notably, prices would be forecasted to be negative at CM values above about 7 percent (a problematic result as capacity prices can not be negative). In addition, using a linear formulation, forecasted capacity prices do not increase more quickly as margins become very small, a result that seems both intuitively unlikely and appears to poorly match the observed data. A better approach, therefore, is to use a curve instead of a line to express the relationship between CM and the price of capacity. The relationship between CM and capacity price is developed and shown in Figure 3.[28]

[28] Historical data were explained more effectively by transforming the independent variable (CM) using a function of the form $X' = (X - X_0)^P$ where $X_0$ is a constant and P is a constant that is negative. The resulting nonlinear regression equation is of the form $Y = m(X - X_0)^P + b$, where m and b are the standard constants in a linear equation.

Figure 3: Relationship Between Capacity Margin and Capacity Price Using Nonlinear Regression (PJM Interconnect, June 1999 – August 2004)




This new equation explained the observed data much better.[29] In addition, the function has two characteristics that better match the relationship between CM and capacity price that would be expected: a) The capacity price drops near to but does not fall below zero as CM increases to high values; and b) The capacity price increases quickly as CM approaches a low value. For these reasons, this equation was selected as the basis for forecasting future reserve prices.[30]

One additional expected characteristic of capacity prices could not be estimated using historical data. Market participants that fail to fulfill their capacity obligations are obligated to pay a deficiency charge based on a deficiency rate that is currently set at about $170/MW-day.[31] Because parties that are short pay a fixed penalty, the use of a deficiency charge will tend to limit capacity auction prices. In particular, rational bidders will not wish to purchase capacity through the auction at a price greater than the penalty that they would be forced to pay should they fail to

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[29] The resulting in a correlation coefficient is 0.810 ($R^2$ = 0.6558).

[30] Redefining X as the CM and Y as the forecasted capacity price, the following equation is obtained:

$P = 0.0111(CM + 0.038)^{-3} + 5.978$, where P = Forecasted Capacity Price and CM = Capacity Margin.

[31] This value is based loosely on the levelized cost of a new combustion turbine.

procure adequate capacity. Thus, clearing prices above the $170/MW-day penalty level are unlikely, but may still occur under certain circumstances.[32]

Very little experience exists with auction prices at these high levels – certainly not enough to estimate a mathematical relationship based on historical data. Nevertheless, the impact of deficiency penalties seems likely to have a large effect on auction prices in forecast periods where prices would otherwise exceed the deficiency level. For this reason, forecast prices above $170/MWH were heavily dampened to simulate this effect. This was accomplished by applying the following formula in instances where the forecast equation presented above produces prices above $170/MW-Day:

$$P_F = (P_I - 170)^{0.7} + 170$$

Where: $P_F$ = Final Forecasted Capacity Price; and
$P_I$ = Initial Forecast Capacity Price (from forecast equation)

While insufficient historical data with such high prices exists to estimate a specific relationship, this additional procedure provides a reasonable and necessary adjustment in instances where capacity is short and prices might not otherwise be limited in any rationale manner. The deficiency penalty provides a backstop that will discourage participants from buying capacity at very high prices through the PJM administered auctions and should be accounted for in forecasting. The adjustment described above becomes progressively more important as prices rise. Initial prices below $170/MW-Day are unaffected. If prices are initially forecast to be slightly more than $170/MW-Day, results are not greatly affected. For example, at $180/MW-Day, the adjustment would produce a final forecast of $175/MW-Day ($170 + 10^{0.7} = 175$). The impact of the adjustment increases, however, as prices rise. For example, if prices are initially forecast to be $500/MW-Day, the adjustment would produce a final forecast of $227/MW-Day ($170 + 330^{0.7} = 227$).

4. Capacity Price Forecast Assumptions and Results

Five capacity price forecasts are completed for the period for the period September 2004 through December 2010 – one baseline case and four sensitivity cases. Table 6 presents the assumptions for each of these forecasts.

[32] Penalties may be assessed over a longer period than that for which capacity is being sold in an auction. For example, bids above $170/MW-Day in daily auctions may be made in order to avoid $170/MW-Day penalties over a much longer period. The basis for the $170/MW-Day penalty is the daily carrying cost of a gas turbine.

Table 6: Summary of Assumptions for Capacity Price Forecasts

| | Queue Treatment - by Project Status | | | Projects in 2009-10 (Post Queue) | Capacity Imports | Capacity Retirements |
|---|---|---|---|---|---|---|
| | Partially In-Service | Under Construction | Under Study | | | |
| **1) Baseline** | 100% Likely to be Completed | 90% Likely to be Completed | 35% Likely to be Completed | Equal to 2008 Queue Levels | Approximately 25% Drop from 2003 Levels | 25 MW per Month in 2005-06 (600 MW) |
| **2) Low Expansion** | 100% Likely to be Completed | 85% Likely to be Completed | 25% Likely to be Completed | Equal to 2008 Queue Levels | Approximately 25% Drop from 2003 Levels | 25 MW per Month in 2005-06 (600 MW) |
| **3) High Expansion** | 100% Likely to be Completed | 100% Likely to be Completed | 50% Likely to be Completed | 150% of 2008 Queue Levels | Approximately 25% Drop from 2003 Levels | 25 MW per Month in 2005-06 (600 MW) |
| **4) Low Imports** | 100% Likely to be Completed | Same as Baseline | Same as Baseline | Same as High Expansion | Decreases to About 15% of 2003 Levels | 25 MW per Month in 2005-06 (600 MW) |
| **5) High Retirements** | 100% Likely to be Completed | Same as High Expansion | Same as High Expansion | Same as High Expansion | Same as Baseline | 150 MW per Month in 2005-06 (3,600 MW) |

The assumptions chosen for these analyses were selected to span a wide range of possible future pricing scenarios. Differences between forecasts focus on the variables likely to have the most significant impact on capacity prices. Of particular importance is the fraction of capacity assumed to be constructed that is currently listed in PJM's interconnection queue. In addition, forecasts varied by levels of capacity imports and retirements, two additional factors subject to significant uncertainty over the forecast period that are capable of producing large swings in capacity prices.[33]

Table 7 presents annual average values for the five price forecasts. Results vary significantly depending on assumptions.

[33] Assumptions regarding load growth affect the capacity market indirectly through PJM's load forecast and resulting capacity requirements. Such forecasts are likely to vary less significantly than actual load over the forecast period and thus are likely to have a less significant impact on price forecasts.

Table 7: Summary of Results for Capacity Price Forecasts
(PJM Interconnect, September 2004 – December 2010)

| Forecast ($/MW-Day) | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Baseline | 19.85 | 24.81 | 32.73 | 49.02 | 66.63 | 98.43 |
| Low Capacity Expansion | 21.11 | 28.48 | 41.70 | 72.92 | 119.57 | 168.98 |
| High Capacity Expansion | 18.09 | 20.47 | 23.78 | 30.18 | 29.84 | 27.10 |
| Low Capacity Imports | 26.42 | 42.70 | 62.95 | 108.04 | 130.74 | 143.52 |
| High Capacity Retirements | 24.01 | 58.00 | 114.13 | 154.63 | 150.37 | 126.86 |

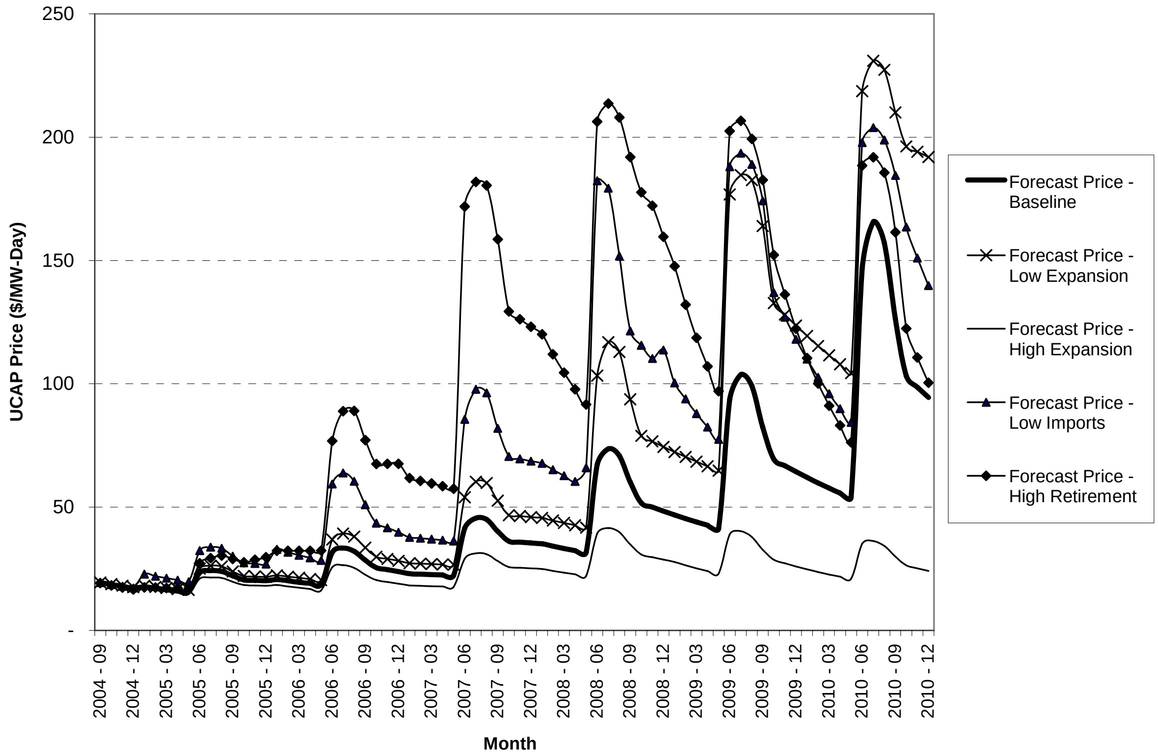
Table 8 provides the actual and forecasted capacity benefits of the CEACP using the baseline forecast and the capacity benefits by utility presented in Table 3. Capacity values utilize the baseline case forecast.

Table 8: Baseline CEACP Unforced Capacity Benefits
(PJM Interconnect, 2005 – 2010, Thousands of Dollars)

| **Utility** | **2005** | **2006** | **2007** | **2008** | **2009** |
|---|---|---|---|---|---|
| Conectiv | $ - | $ - | $ - | $ - | $ - |
| JCP&L | $ 449 | $ 551 | $ 713 | $ 1,047 | $ 1,394 |
| PSE&G | $ 1,085 | $ 1,356 | $ 2,091 | $ 3,131 | $ 4,256 |
| TOTAL | $ 1,534 | $ 1,907 | $ 2,804 | $ 4,178 | $ 5,650 |

A complete picture of the forecasted prices can be seen by graphing monthly results as shown in Figure 4. Significant monthly variation occurs in later years of the forecast where CM is smaller and small monthly variations in the amount of capacity assumed available have a substantial impact on price. Each forecast is discussed in more detail below.

Figure 4: Summary of Results for Capacity Price Forecasts
(PJM Interconnect, September 2004 – December 2010)




a) Baseline Forecast

The baseline case assumes new projects will be completed at a rate that is consistent with current PJM forecasts and that capacity imports continue at about 2003 levels. Modest levels of retirement are also assumed. Prices are forecast to increase slowly, reaching $50 per MW-Day in the Summer of 2008. (Values are slightly less - $49.02 when shown as an annual average – See Table 4). Prices reach $100 per MW-Day in the Summer of 2009 when surplus capacity drops to about 1% and continue upward in 2010. Prices stay relatively low through 2007 due to the current excess of capacity and continued capacity additions from queue projects. Prices increase sharply beginning in 2009 due to load growth and reduced levels of capacity additions.

b) Low Capacity Expansion Forecast

The low capacity expansion forecast assumes only a quarter of capacity under study in the queue is completed. Such lower levels of completion may occur, for example, if investor sentiment regarding the attractiveness of PJM’s markets is particularly negative and relatively few projects are pursued to completion.

Due to this reduced level of capacity additions, prices in this forecast increase more quickly than in the baseline case, exceeding $100 per MW-Day in the Summer of 2008 when surplus capacity drops below 1%. Prices continue to increase and are significantly dampened by the presence of the deficiency penalty/price limit in 2010. Price are suppressed initially by the current surplus which still manages to contain prices through 2007. By 2010, the pool is no longer meeting its capacity obligation and some participants opt to pay the deficiency penalty rather than purchase capacity through the auction.

c) High Capacity Expansion Forecast

The high capacity expansion forecast assumes that fully half of capacity under study in the queue is completed. Given the current levels of capacity reserves, such higher levels of completion appear likely to occur only if actions are taken that significantly increase overall revenue expectations from the markets. More capacity may be constructed, for example, if the PJM energy market became significantly more attractive in the near term. In this forecast, due to increased levels of capacity additions, capacity prices stay below $50 per MW-Day and margins stay above 3% throughout the forecast period.

d) Low Capacity Imports Forecast

Much of the current surplus of capacity results from capacity imports. For example, in 2003, net capacity imports provided an average of about 2,000 MW of capacity to the PJM market, or almost 3 percent of the overall market requirement.[34] The level of net imports varied over the year, tending to be higher in non-summer months when capacity margins are higher in neighboring pools. This forecast assumes that annual average capacity imports drop to 15% of their 2003 levels by 2006. In addition, net imports of capacity are assumed to drop to zero in key summer months. Such changes in the import/export balance for capacity are not unreasonable given the large change in the recent history of PJM and potential for tighter reserve margins with load growth in neighboring regions. In fact, this scenario may underestimate the potential impact of capacity trading with neighboring pools if PJM were to become a net exporter as it was as recently as 2000. Finally, the low capacity imports forecast also assumes that somewhat higher levels of capacity additions for years 2009 and 2010 as a result of higher capacity prices in the 2006 to 2008 timeframe.

For this forecast, capacity prices exceed $50 per MW-Day as early as 2006 and continue to rise above $150 per MW-Day in 2008. The impact of decreased imports is mitigated somewhat by the assumption that more capacity would be added in 2009 and 2010, but the pool still becomes short of capacity in the summer months in these years. As a result, prices are forecast to be above $150 during most months of 2009 and 2010. The impact of the deficiency penalty dampens prices somewhat during the summer months of this period.

- High Capacity Retirements Case.

The high capacity retirements case assumes that more significant amounts of capacity (3,600 MW) retire in the years 2005 and 2006. Such increased levels of retirement may occur, for example, due to the low prices currently prevailing in the pool and the potentially high costs of keeping aging, and less efficient units operable.

[34] See section 4 of PJM's "2003 State of the Market Report," prepared by PJM's Market Monitoring Unit (March 4, 2004).

This case produces the most significant increase in capacity prices in the near-term. The increase is prices, however, is mitigated significantly by 2010 due to assumptions that increased capacity additions (based on the high expansion case) will result.[35] Capacity prices remain low in 2005 but approach $100 per MW-Day in the Summer of 2006 and exceed $200 by the Summer of 2008 due to a shortage of capacity pool-wide. Prices drop somewhat in 2009 and 2010 due to increased additions. By 2010, the pool almost meets its capacity obligation in all months. The impact of the deficiency penalty plays a significant role in dampening prices, particularly during 2008 and 2009 when the pool is significantly short of capacity in the summer and some participants are forced to pay the deficiency penalty.

### 5. Discussion of PJM Capacity Price Forecast

#### a. Overview Discussion

Capacity prices appear likely to remain relatively low through Spring of 2006. According to all forecast scenarios, capacity prices will stay below $50 per MW-Day at least until the requirement is increased for the 2006-07 Power Year (i.e., in June 2006). This conclusion is supported by forward auctions for capacity held by PJM, which includes sales for months extending through May of 2005.[36] Beginning with the Summer of 2006, capacity prices are subject to significantly greater uncertainty. Prices are likely to increase notably when CM falls below the 2 percent level. When such relatively small amounts of capacity are available, even very small changes in assumptions have very large impacts on pricing.

Of particular importance to any forecast are the assumptions regarding the level of capacity likely to be added within the PJM control area. Current market trends as well as the number of projects in the interconnection queue suggest that the pace of capacity additions is likely to slow in the near term. Thus, at least some increase in capacity price above the current relatively low level appears inevitable. The extent and duration of capacity price increases will depend in large part on the willingness of investors to further invest in PJM's markets. The forecasts presented here are intended to capture a full range of possible results. There is general recognition that significant concern currently exists among investors about the attractiveness of newly deregulated electricity markets. While each scenario presented here clearly lies within the range of possibility, specific assertions about the likelihood of each are outside the scope of this study.

It is equally important to note that PJM is in the process of making significant changes to its capacity market, including changes that affect the calculation of required capacity, the manner in which the market clears, and the definition of the capacity product. Thus, as discussed further below, changes in the structure of PJM's capacity market are also likely to significantly affect future capacity pricing.

#### b. Characteristics of Pricing

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[35] This forecast could be renamed the High Capacity Turnover" case due to increased levels of both retirements and construction.
[36] For example, a capacity auction for the months of January through May of 2005 held by PJM in May of 2004 cleared at $25/MW-Month.

The forecasting equation developed in this study was presented in Figure 3. As shown in the forecast equation, capacity pricing can be broken into two distinct conditions. At Capacity Margins above 2 percent, the forecasted price of capacity does not vary significantly – ranging from about $10 to $60 per MW-Day. Prices observed to-date in the market behaved as expected. In no instances when a greater than 2 percent CM existed did average monthly prices exceed $68 per MW-Day. When CM drops below 2 percent, forecasted prices change quickly with changes in capacity. At 1 percent, forecasted prices exceed the $100 per MW-Day level. Taken as a whole, historical data also is considerably more volatile, ranging all the way from just under $20 to just over $200 per MW-Day. While a higher CM always produces relatively low average monthly prices, lower CMs may produce prices that are high or low, but result in much higher expected values.

Thus, each of the forecasts is most easily understood through the factors (or combination of factors) that result in the pool reaching the 2 percent threshold level. This threshold is reached most quickly in the high capacity retirement scenario with significant price increases by the Summer of 2006. Changes in the mix of capacity imports and exports also have the potential to significantly affect prices in this timeframe.

By the Summer of 2008, all forecasts except the high capacity expansion case include months with CMs of 2 percent of less. Thus, in the later years of the forecast period, forecasts are extremely sensitive to small changes in the level of capacity assumed. Of particular importance to any forecast are the assumptions regarding the level of capacity likely to be added within the PJM control area.

In the baseline case – the case consistent with PJM's own forecasts of capacity additions and resultant reserve margins – CM first falls below the 2% level in the Summer of 2008. While this scenario provides a reasonable baseline forecast, it is extremely important to note that even small changes in baseline assumptions produce wide swings in the forecasted price for capacity in the 2007 to 2010 timeframe. Thus, relatively small changes in the portion of proposed projects assumed to be completed as well as changes in import or retirement assumptions all greatly impact resulting capacity revenue forecasts. In short, accurate capacity prices are extremely difficult to forecast beginning in the Summer of 2007.

While the forecast equation produces prices that are progressively more and more volatile as CM decreases, the presence of the deficiency penalty significantly dampens prices as CM reaches near the 0% level (below levels of about 0.25%). In three of the five forecasts conducted, prices reached the $170 per MW-Day deficiency level and were adjusted to account for this factor. This is a reasonable result. Under current market rules, for example, it is very unlikely that prices could be sustained over $200 per MW-Day as participants would prefer to pay deficiency penalty. While this effect could not be confirmed based on historical data, it may prove an important factor in determining future capacity prices.

c. Impact of Proposed Market Reforms

The particular manner in which PJM's capacity market has historically cleared – at low and predictable prices at CM above 2 percent and at volatile and potentially very high prices at CM below two percent – has been the subject of considerable criticism. Market stakeholders have noted that such pricing may do little to provide incentives for investment because it does not create a stable, long-term investment signal. The current market design may also be unduly subject to efforts to exercise market power because even small changes in available capacity may have a substantial impact on clearing prices. In efforts to address these concerns and others, two neighboring pools have already taken action to reform their capacity markets by introducing a price clearing mechanism likely to provide a more stable and substantial capacity price signal. In 2003, the New York Independent System Operator implemented a capacity "demand curve." Rather than utilize a single capacity requirement and limit prices through the use of a single deficiency penalty, New York now clears its capacity market using a capacity requirement that varies depending on the offer price at which capacity is available in the region. The demand curve provides a downward sloping price schedule whereby the market clears at progressively lower prices as CM increases. ISO New England has proposed use of a similar curve, but has not received approval for a specific market design from federal regulators.[37]

PJM now appears poised to adopt the use of a demand curve intended to better align the price paid for capacity with the reliability benefits that capacity provides. PJM is also developing a capacity pricing mechanism, the "Reliability Pricing Model" or RPM, that would produce prices for capacity that distinguish between a much more extensive number of attributes, including location, the ability to cycle on and off quickly, as well as the type of fuel utilized. In the current market design, all capacity is treated as a single product, "unforced capacity," in which the only distinction made between resources is an adjustment in capacity rating that takes into account the forced outage rates of individual capacity resources.

Key details regarding these proposed reforms are still in draft form.[38] Design decisions that will have a substantial impact on future capacity prices include the shape of the demand curve, the specific attributes of capacity that are recognized and valued, and the method of calculating requirements for capacity with those attributes. In addition, the exact treatment of demand-side resources is unclear, though PJM has indicated that demand-side resources would be included on a comparable basis.

PJM is currently targeting the Power Year from June 2006 through May 2007 for implementation of the RPM. Thus, capacity forecasts based on the existing design (including the forecasts presented here) may prove inadequate. At the same time, given the lack of detail in the proposed RPM, any attempt to forecast prices based on its use would be highly speculative and premature.

Nevertheless, it is possible to draw some qualitative conclusions about the likely impacts of PJM's proposal. In particular, the use of a demand curve smoothes prices, producing prices that are more consistent at low capacity levels. Higher prices are particularly likely to result when CM is in the range of about 3 to 9 percent (i.e., when sufficient capacity exists to produce low capacity prices absent use of a demand curve). In addition, using the RPM, capacity

[37] The Federal Energy Regulatory Commission (FERC) approved use of a demand curve in New England, but established hearing procedures regarding specific issues related to the shape and use of the curve. Implementation is currently set for January 2006 (See Docket No. ER03-563-030 and EL04-102-000).
[38] The RPM is being developed, in part, through a stakeholder process. Key documents describing PJM's proposal and open issues are located at: http://www.pjm.com/committees/working-groups/pjmramwg/pjmramwg.html.

resources with particular attributes will receive higher capacity payments. Of particular importance, resources in import-constrained areas are likely to receive higher payments. Premiums may also result for resources that are flexible (e.g., can be called within 30 minutes, as the CEACP). These proposals, if adopted, should increase the value of the CEACP but the amount of the increase cannot be determined at this time. Some of these factors may be applicable to the New Jersey situation.

## D. Energy Benefits of the CEACP

The second category of benefits resulting from the CEACP is the reduction in energy costs due to shifting energy demand from high priced hours, e.g., 1 pm, to lower cost hours, e.g., 6 pm. The amount the CEACP reduces the total net energy that is consumed depends on the temperature and humidity.[39]

To evaluate the energy benefits of the CEACP, the activation history of the program was reviewed. Only JCP&L operates the program to reduce energy costs. Conectiv has not triggered the program since 1997 and did not report any historical energy benefits or forecast any in its response to the data request. For JCP&L, the energy savings from the program were reported.[40] PSE&G indicated only that the historical and forecasted energy benefits would be positive and did not provide any specific values. Using the same methodology that JCP&L used, however, the energy benefits for PSE&G were determined.[41] Table 9 reports the energy savings for all three utilities during the years 2000 through 2004.[42]

Table 9: Energy Benefits from the CEACP for Years 2000 through 2004 Based on Current Activation Criteria (Thousands of Dollars)

| Utility | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|
| Conectiv | $0 | $0 | $0 | $0 | $0 |
| JCP&L | $105 | $973 | $207 | $76 | $0 |
| PSE&G | $0 | $223 | $10 | $0 | $0 |
| TOTAL | $105 | $1,196 | $217 | $76 | $0 |

Three observations should be made regarding Table 9. First, note that the annual energy benefits are volatile. The annual total across all three utilities range from a low of a low of $0 in 2004 to a high of almost $1.2 million with an average over these five years of $335,000 (adjusted for inflation in 2005 $)[43]. This volatility should not be surprising since the causes of high prices are due in part to random events such as generation and transmission outages and weather. Second, PSE&G's energy benefits are small compared to JCP&L even though the number of MW in its program is larger than JCP&L's because PSE&G does not activate the program based

[39] Final Report 2001 Direct Load Control Evaluation, Xenergy (prepared for PSE&G), March 7, 2002, Section 3.
[40] See response to Question 3.
[41] The methodology used was provided in RAR-DSM-12 in the above-cited document. It consists of taking the difference between the average locational marginal prices during the hours that the program was activated minus the average of the two subsequent hours and multiplying by the amount of load activated.
[42] See the responses to Questions 3 and 8.
[43] Inflation assumed to be 2.5% per year.

on energy prices. If PSE&G were to activate its program in a manner similar to JCP&L, the energy benefits would be larger. (This issue is discussed more extensively in Section V including re-calculating the energy benefits assuming Conectiv and PSE&G operated their programs similar to the way JCP&L operates its program.) Third, the amount of energy savings is relatively small compared to the cost of the program, which exceeded $5.9 million in 2003 as indicated in Table 2.

For the cost-benefit analysis, the forecasted annual energy benefit combined from all three programs is assumed to be $335,000 in 2005 (average of 2000 to 2004) and is escalated at 5% per year. This escalation rate accounts for rising natural gas prices and expected supply tightening in the PJM market over the next 5 years.

### E. Transmission, Distribution and Reliability Benefits

Each utility was asked to provide an estimate of the transmission and distribution (T&D) benefits of the CEACP. In theory, the CEACP should result in some avoided T&D expenditures by reducing peak demand. This information is specific to each utility, however.

Two of the three utilities did not provide quantifiable T&D benefit estimates.[44] Conectiv mentioned that it has not activated its program since 1995. Such lack of use may suggest that if any T&D benefits exist they are likely to be negligible. JCP&L stated: "The Company has no current assessment of potential avoided costs for transmission or distribution as the potential of appliances cycling as a viable supply planning substitute is situational and unproven."[45] The company also noted that the program "enables cycling of customers in the Larabee to Point Pleasant area, independently of other programs participants and has been used during a transformer bank failure to support reliability."[46] In response to Question 10, which requests that the company provide the reason for each activation event, JCP&L only listed "PJM Event" as a reason and only for some of the activations. No reason was provided for the remaining activations. It is not clear if and how many times the program was activated for local T&D reasons as opposed to high locational marginal prices. During the technical review process, JCP&L supplemented its response in this area by stating that quantifying T&D system reliability improvements from the CEACP program is difficult, that at best, the CEACP program will temporarily defer the need for upgrades, but does not provide the opportunity to reduce permanently the need for upgrades.

PSE&G's reported $0 for avoided transmission costs both historically since 1995 and in the future. For avoided distribution costs, PSE&G reported "not available." PSE&G also noted that all of the times it activated the program since 1998 were initiated by PJM except when the program was activated for evaluation purposes in 2000 and during the blackout in August 2003. The lack of readily available estimates for T&D benefits of the CEACP is and of itself is not an indication that the benefits are small, but the activation history suggests that these benefits are not substantial. (In Section V below, this issue is also discussed in the context of evaluating

[44] See response to Question 3.
[45] See response to Question 3.
[46] *Op cit.*

options to changing the existing program.) As a result, for the purposes of the cost-benefit analysis, these benefits were treated as a modest qualitative benefit that should be considered when assessing the numerical results.

The vast majority of the time that the program is activated by the utilities, appliances of all participating customers are activated as opposed to activating targeted customers, for instance those in a distribution hot spot.[47] JCP&L, in the times it has triggered the program, always activated all of the participants. Only during the recovery after the August 14, 2003 blackout did PSE&G activate a subset of participants (with the one other exception being during a program evaluation study). JCP&L has only activated a subset of its participants' appliances three times out of sixty-four times.[48] This activation pattern suggests that the program does not provide targeted T&D benefits for particular parts of the utilities' systems.

### F. Increased PJM Market Efficiency Benefits and Temporary Economic Transfers

The CEACP's reduction in demand may also improve the efficiency of the PJM wholesale energy market and result in transfers from producers to consumers. To be specific, the transfers are from generators to the winning BGS auction suppliers and eventually end-users of electricity, assuming competitive market conditions. As JCP&L noted, "Additional value may exist in 'market pricing effects' that can result from reduced load during extreme pricing periods. The value of market effects is speculative."[49] By reducing demand during peak hours, the CEACP would reduce the wholesale market locational marginal price. Even a small reduction in price, according to this view, would result in a substantial benefit since all of the megawatt-hours bought in the market would be paying this lower price.[50] For instance, JCP&L concludes that assuming savings due to this effect could have been an additional $1.8 million dollars for JCP&L customers over the period from 2000 to 2001.[51]

The reduction in locational marginal prices due to the ECACP consists of two parts. One is an efficiency benefit beyond the energy benefits described in Section IV. D previously by reducing market power; the other is a transfer of money from suppliers to consumers. Given how the New Jersey BGS Auction is structured, in this context, the suppliers are generators and the consumers are load-serving entities. To explain the importance of this distinction, some background is necessary.

Figure 4 illustrates the consumer and producer surplus associated with illustrative supply and demand curves in a market. The greater the sum of consumer and producer surplus, the larger the societal benefits. Consumers who were willing to pay a price above $P_o$, as reflected in

[47] See responses to Question 10.
[48] This does not include the two times JCP&L activate the program but did not state whether the total population or a subset was activated.
[49] *Op cit.*, RAR-DSM-7.
[50] Although much of the load in PJM purchases energy via bilateral contracts and not through the day-ahead or real-time energy spot markets, prices in the bilateral market reflect prices in the spot markets since buyers and sellers can always forgo a bilateral contract for the spot market.
[51] *Op cit.*, RAR-DSM-7. This $1.8 million assumes that the program is triggered when market prices exceed $100/MWh.

the downward sloping demand curve, experience consumer surplus. This surplus derives from only having to pay $P_o$ when they would have been willing to pay more to obtain the product. Conversely, producers that would be willing to produce at a price below $P_o$ are better off by being paid $P_o$ than being paid at the lower price many would have been willing to accept. The difference between $P_o$ and the minimum price at which they would be willing to produce (normally their production costs) is the producer surplus that they experience.

Figure 4: Illustration of Consumer and Producer Surplus

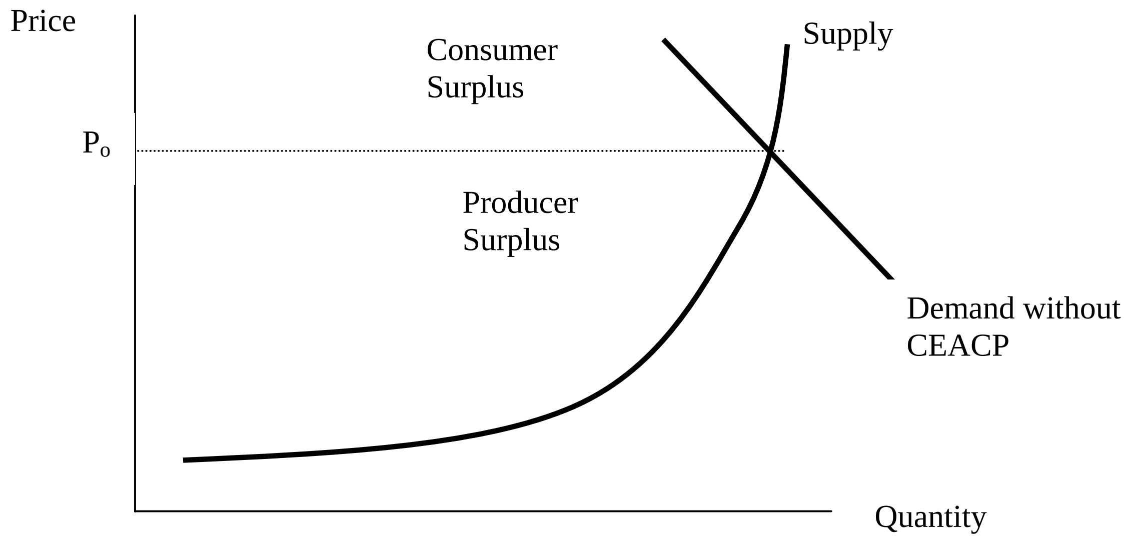
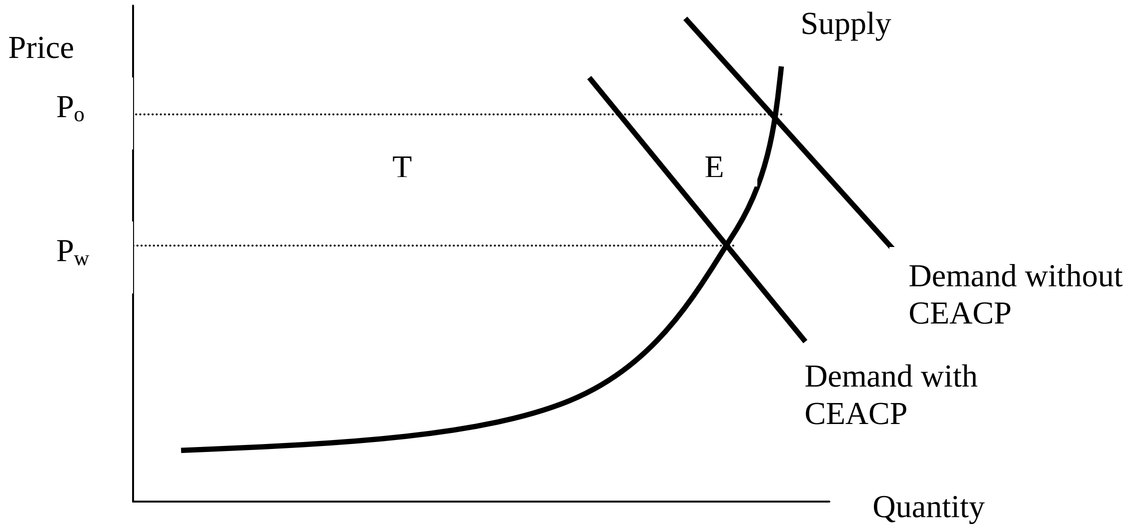



Figure 5 illustrates the difference between the efficiency benefit, denoted by the triangle-like shape labeled E, and the transfer from suppliers to consumers, denoted by the trapezoid-like shape T.[52] Notice that the area denoted as T is much larger relative to the area denoted as E.

[52] The actual changes in the demand curve due to the CEACP are more complicated than illustrated in this figure.

Figure 5: Reduction in Demand due to the Appliance Cycling Program Results in Efficiency Benefits and a Transfer from Suppliers to Consumers




The transfer from suppliers to consumers is not an efficiency gain because it does not result in a better use of society's limited resources, but only in the level of payment made for those resources. Policymakers and regulators concerned about consumers may want to count the transfer also as a benefit, but whether it is permanent benefit to consumers is more complicated. For example, if market power exists, then the CEACP reduces the ability of suppliers to exercise market power, which provides efficiency and transfer benefits that tend to permanently accrue to consumers. If the market is competitive, however, the reduction of payments to suppliers may result in some suppliers not being able to cover all of their fixed costs from the capacity market alone, requiring them to exit the market or forego future investment, which may ultimately result in higher prices to consumers than an analysis that does not consider this effect would suggest. Consequently, the competitiveness of a market is a crucial determinant in the permanency and amount of the transfer payments.

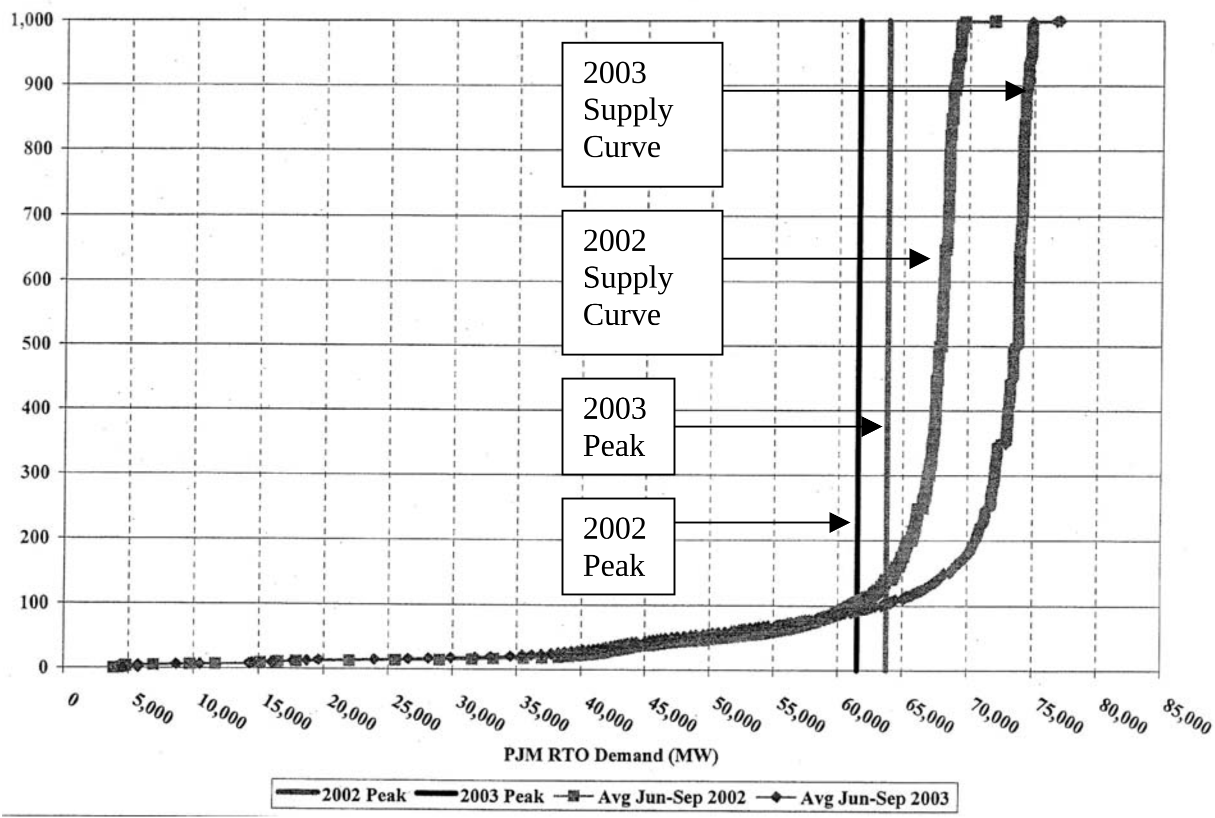
Based on the PJM Market Monitoring Unit's *2003 State of the Market* study, the PJM market is assumed to be generally competitive during periods of peak demand. Whether this is the case is a critical factor in assessing the benefits of the ACP. According to PJM's Market Monitor, the energy and capacity market results were competitive in 2003 but there are potential threats to competition in both these markets. Market participants have some ability to exercise market power under certain conditions and increasing demand-side responsiveness should be evaluated.[53] In general, energy market power becomes a concern during periods of tight supply and demand conditions, such as on hot summer days when the program is triggered. The PJM Market Monitor noted the importance of demand side participation in the wholesale market: "A functional demand side of the wholesale energy market will also tend to induce more competitive behavior among suppliers and will tend to limit the availability to exercise market power."[54] The

[53] PJM Market Monitoring Unit, *2003 State of the Market*, March 4, 2004, pp. 15-16.
[54] PJM Market Monitoring Unit, *Assessment of PJM Load Response Programs*, Compliance Report to the Federal Energy Regulatory Commission, Docket No. ER02-1326-006, December 31, 2003, p. 3.

PJM Market Monitor states that quantifying these benefits are difficult to assess and that only focusing on what may be quantifiable "may be significantly misleading."[55]

Figure 6 is the PJM System Aggregate Supply Curves for years 2002 and 2003 along with the peaks for those years.[56] If demand is high, an approximate 210 MW load reduction, which is approximately the size of the CEACP if all three utilities participated in the PJM ALM program, out of hourly demand of 70,000 in 2003 may result in a meaningful reduction of wholesale prices and result in a substantial transfer from producers to consumers. During lower load periods, however, there would not be a measurable reduction. Figure 6 indicates that in 2003 the price increases from approximately \$400/MWh at a demand of 72,500 MW to \$900/MW at a demand of 75,000 MWh. This means that for every 1 MW of reduction at prices above \$400/MWh, the wholesale price would decrease by \$0.25.

Figure 6: PJM System Aggregate Supply Curves for 2002 and 2003 and Associated Peak




To provide an estimate of this transfer, the number of hours that the PJM wholesale prices equaled or exceed \$400/MWh were counted during each summer from years 2000 to 2004

[55] *Op cit.*
[56] *Op cit.* The aggregate supply curve does not account for transmission constraints. Specific nodal prices in New Jersey may be different from average PJM prices.

inclusive.[57] There were 30 hours such hours.[58] Assuming that when prices exceed $400/MWh, triggering the CEACP of 210 MW results in a $52.5/MWh (= 211 MW*$0.25/MW) drop in price and that the amount of demand throughout PJM is approximately 70,000, the total transfer from producers to consumers over this five-year period would be $110.25 million. This would average out to be $22 million per year. For the purpose of the cost-benefit analysis if the transfer were to be counted as a benefit, for illustration purposes it is assumed that only 10%[59], or $2.2 million, of this transfer results in a permanent benefit to consumers throughout PJM. The less competitive one believes PJM is, the larger amount of the transfer payment would be permanent because the reduction in generation profits above competitive levels would not result in associated retirements and would merely be reducing their market power. It is important to note that this is under the assumption that all three utilities activate the program when energy prices are high; currently only JCP&L does so.[60] However, since all three utilities do not currently activate the program when energy prices are high, this benefit was considered negligible and was not monetized in the cost benefit analysis under current program operation. It is, however, considered in the analysis assuming that all three utilities activate the program in a coordinated fashion when energy prices are high.

Whether and how this potential transfer should figure into the evaluation of the CEACP is a decision that the Staff should confront. In addition, New Jersey consumers that are supplied electricity via the BGS Auction are already hedged; thus, the CEACP could be a hedge for the suppliers under the BGS Auction if they could trigger the program or if firm protocols existed that triggered the program during high energy prices. These suppliers, however, may have alternative and less expensive ways of managing their portfolio risks.

### G. Cost-benefit Calculation of the Existing CEACP

This section conducts the cost-benefit analysis of the CEACP as currently operated.[61] The next section re-calculates the cost-benefit analysis assuming that a range of improvements is made to the program. The cost-benefit analysis uses the total resource cost test, sometimes referred to as the societal resource test.

Annual comparisons of the costs and quantifiable benefits are conducted under the various capacity price forecasts. Payments to customers that are in the CEACP are costs

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[57] The PSE&G zonal prices were used as reported by PJM. All three New Jersey zonal prices for Conectiv, JCP&L, and PSE&G are extremely highly correlated (with correlation coefficients above 0.99). PSE&G's zonal prices were used since it is the largest participant in the CEACP.
[58] There were 20 hours during these five summers when the price was between $200/MWh and $400/MWh inclusive.
[59] The figure 10% was chosen only to illustrate the possible permanent benefit of the transfer from producers to consumers. It is assumed for purposes of this study that most of these savings from the reduction in demand are short-term. If the market is not competitive, however, such savings would be likely to be permanent and the 10% assumption may underestimate the amount of transfer benefit that consumers would receive.
[60] These 30 hours occurred on nine separate days. On five of these nine days, both PSE&G and JCP&L activated their programs. On one of the remaining two days, PSE&G activated the program and JCP&L on the other three.
[61] In some cases the benefits of the CEACP are New Jersey specific and in other cases they accrue to all of PJM. Other states may have similar programs with some benefits accruing to New Jersey electricity consumers.

necessary to compensate them and therefore are included as costs in the cost-benefit analysis.[62] Since in the past customer compensation has been treated as a transfer payment and not as a cost, the cost-benefit analysis is also reported as if these costs were a transfer payment. It does not include any T&D benefits since a monetary quantification of this benefit is not available. Consequently, the cost-benefit analysis understates the total value of the program.

Table 10 compares annual benefits to annual costs from 2005 through 2009 of the CEACP using the baseline capacity prices developed above along with the energy and market efficiency benefits. Energy prices are based on New Jersey, real-time, zonal prices for each utility. <u>It does not include any market transfer benefits since only one of the three utilities triggers the program due to high-energy prices nor does it include any reliability or avoided T&D benefits.</u> The costs exceed the benefits but that difference decreases as the PJM capacity market tightens. Also, the capacity benefits provide the largest share of the benefits (equal to or exceeding 80% for all years).

Table 10: Annual Costs and Benefits of the CEACP Using the Baseline Capacity Prices (in Thousands of Dollars - Numbers may not add to total due to independent rounding)

| | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|
| <u>Costs</u> | | | | | |
| Total Costs | $ 7,193 | $ 7,325 | $ 7,140 | $ 7,068 | $ 7,093 |
| Costs Not Including Customer Payments | $ 2,823 | $ 2,991 | $ 2,842 | $ 2,806 | $ 2,867 |
| | | | | | |
| <u>Benefits</u> | | | | | |
| Capacity | $ 1,534 | $ 1,907 | $ 2,804 | $ 4,178 | $ 5,650 |
| Energy | $ 335 | $ 352 | $ 369 | $ 388 | $ 407 |
| Transmission and Distribution | Company estimates were not available | | | | |
| Market Efficiency and Transfers | Assumed to be negligible without coordinated program operation | | | | |
| TOTAL QUANTIFIABLE BENEFITS | $ 1,869 | $ 2,258 | $ 3,173 | $ 4,566 | $ 6,057 |
| | | | | | |
| Benefits Minus Costs | $ (5,324) | $ (5,067) | $ (3,967) | $ (2,503) | $ (1,036) |
| Benefits Minus Costs Not Including Customer Payments | $ (954) | $ (733) | $ 331 | $ 1,759 | $ 3,190 |
| | | | | | |
| Net Present Value (NPV) of Benefits Minus Costs (2005 to 2009) | $ (15,451) | | | | |
| NPV of Benefits Minus Costs Not Including Customer Payments (2005 to 2009) | $ 2,429 | | | | |

Uncertainty about the future value of capacity is an especially important factor in assessing the program because it has such a large impact on net benefits. Table 11 summarizes the benefits minus the costs under each of the capacity forecast scenarios for years 2005 through 2009. The results for the baseline capacity forecast are repeated for ease of comparison. Table 11 assumes the same amount of energy benefits for each capacity scenario, although the energy

[62] Including customer compensation as a cost should be done as part of the total resource cost test; doing is not the creation of a new methodology but the correct application of the existing one.

benefits depend, in part, on the amount of capacity relative to demand. A larger surplus of capacity to demand would likely result in less energy benefits than with a smaller surplus.

Table 11: Annual Benefits Minus Costs of the CEACP Using the Various Capacity Price Scenarios (in Thousands of Dollars)

| Capacity Forecast Scenario | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|
| Baseline | $ (5,324) | $ (5,067) | $ (3,967) | $ (2,503) | $ (1,036) |
| Low Capacity | $ (5,226) | $ (4,785) | $ (3,198) | $ (466) | $ 3,453 |
| High Capacity | $ (4,448) | $ (4,246) | $ (3,602) | $ (2,660) | $ (2,711) |
| Low Capacity Imports | $ (4,891) | $ (4,433) | $ (2,829) | $ (78) | $ 3,860 |
| High Capacity Retirements | $ (3,659) | $ 754 | $ 8,435 | $ 13,920 | $ 13,347 |

Using a real discount rate of 6.5% based on the utilities' cost of capital,[63] the forecasted net present value of the CEACP for each of the capacity forecast scenarios is provided in Table 12. The net present value analysis is calculated from 2005 through 2020 based on Table 10 through year 2009.

Table 12: Cost-Benefit Analysis of the CEACP Under Different Capacity Price Forecasts 2005 through 2020 (in Thousands of Dollars)

| Capacity Forecast Scenario | NPV |
|---|---|
| Baseline | ($15,451) |
| Low Capacity | ($9,615) |
| High Capacity | ($14,948) |
| Low Capacity Imports | ($8,086) |
| High Capacity Retirements | $24,774 |

For the baseline capacity price forecast, the net present value of the costs exceeds the benefits by $15.5 million. The program achieves a positive benefit in scenarios where capacity values exceed the baseline forecast. This result is driven by higher capacity prices beginning sometime after the year 2006. In the nearer term, net benefits are generally not seen (See Table 11). For example, only the high capacity retirement scenario would achieve a positive benefit for the 5-year period 2005 through 2009. As noted above and in Table 10, the net benefits would increase substantially if customer payments were treated as a transfer payment instead of as a cost as was done herein.

## V. Program Options for Maximizing the CEACP's Future Value

In this section, a preliminary evaluation of different program options that are not necessarily mutually exclusive is conducted. A fundamental management difficulty with the CEACP is that its benefits cross industry sectors and include market benefits (capacity, energy, and market efficiency) and T&D system support. Designing a program to capture all of these benefits is therefore challenging. With the assistance of Lawrence Berkeley Laboratory, Staff is

[63] See responses to Question 7. Inflation of 3% is assumed to convert the cost of capital to a real cost of capital.

drafting a multi-year plan for the CEACP. Another important consideration is whether the potential transfer of value from producers to consumers due to the CEACP is an important objective for policymakers.

The one overriding recommendation is that whatever the structure of the program that Staff settles upon, the program should have clear objectives and consistent and coordinated implementation.

### A. Option A: Consistent and Coordinated Implementation of Program Activation by Utilities

One option is to require the three utilities to coordinate their activation of the program to obtain larger energy and market efficiency benefits. By activating their programs at the same time and at the same frequency, the impact of activation and benefits would be increased. This option would have no impact on the amount of capacity benefits, since coordination of activating the program is not required to maximize this value.

Although high-energy prices and T&D limitations are likely to be highly correlated, increasing the number of times the program is activated for energy purposes may limit the number of times it can be activated for T&D benefits assuming that the total number of activations per year is restricted. Two of the three utilities limit the number of activation events, therefore any increase in activation for energy reasons reduces the number available for T&D reasons. JCP&L limits activation to 20 times per year; PSE&G's limit is 15 and from this limit reserves 5 activations for local distribution purposes.[64] JCP&L, the only utility that cycles for energy reasons, triggered its program 15 times in 2001 and 19 times in 2002. Therefore, it may be necessary under this option to consider increasing the permissible number of times PSE&G is permitted to activate its program so that it has the ability to also activate the program for T&D reasons. PSE&G may need to change the terms of its agreement with customers, which would need to be reviewed. In addition, Conectiv and PSE&G may incur additional staffing and other costs to be able to trigger the CEACP when energy prices are high.

Table 13 presents the annual costs and benefits of having Conectiv obtaining PJM capacity credits and having both PSE&G and Conectiv operate their portion of the CEACP to obtain proportional energy benefits as JCP&L currently does. It also assumes that the PJM market during periods of peak demand is generally competitive and therefore most savings from a reduction in demand is a transfer payment and not an efficiency benefit. <u>Under these assumptions the net present value is negative 1.8 million, which is substantially greater than the negative $15.5 million net present value calculation under current operations.</u> This large swing in the NPV of the cost-benefit analysis is due to the inclusion of 10% of the estimated transfer from producers to consumers amount as a benefit. Both the amount of this transfer and the percentage that is a permanent benefit to consumers are difficult to quantify. In addition, it should be noted that this transfer benefit is not unique to the CEACP. Building a 210 MW generation facility that dispatches at $400/MWh provide the same transfer and corresponding benefit. Also, this cost-benefit analysis does not consider increases in program costs that may result from the changes

[64] See response to Question 14.

such as conducting the study to qualify Conectiv's capacity for the program and any costs associated with triggering the program due to high energy prices.

Table 13: Annual Costs and Benefits of Having Conectiv and PSE&G Operate Their Portion of the CEACP Similar to the Way JCP&L Operates Its Program (in Thousands of Dollars)

| | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|
| Costs | | | | | |
| Total Costs | $ 7,193 | $ 7,325 | $ 7,140 | $ 7,068 | $ 7,093 |
| Costs Not Including Customer Payments | $ 2,823 | $ 2,991 | $ 2,842 | $ 2,806 | $ 2,867 |
| | | | | | |
| Benefits | | | | | |
| Capacity | $ 1,534 | $ 1,907 | $ 2,804 | $ 4,178 | $ 5,650 |
| Energy | $ 1,203 | $ 1,281 | $ 1,521 | $ 1,621 | $ 1,729 |
| Transmission and Distribution | Company estimates were not available | | | | |
| Market Efficiency and Transfers | $ 2,200 | $ 2,200 | $ 2,200 | $ 2,200 | $ 2,200 |
| TOTAL QUANTIFIABLE BENEFITS | $ 4,937 | $ 5,387 | $ 6,524 | $ 7,999 | $ 9,579 |
| | | | | | |
| Benefits Minus Costs | $ (2,256) | $ (1,938) | $ (616) | $ 930 | $ 2,485 |
| Benefits Minus Costs Not Including Customer Payments | $ 2,114 | $ 2,396 | $ 3,682 | $ 5,192 | $ 6,711 |
| | | | | | |
| NPV of Benefits Minus Costs (2005 to 2009) | ($1,799) | | | | |
| NPV of Benefits Minus Costs Not Including Customer Payments (2005 to 2009) | $16,081 | | | | |

### B. Option B: Require Conectiv to Qualify their Program Under PJM's ALM Program

Currently, Conectiv capacity does not qualify for PJM capacity credit. Assuming that approximately 11 MW would be eligible, which would require documentation in accordance with PJM's requirements, this would provide an additional stream of benefits identified in Table 14 (not including any cost associated with satisfying the PJM requirements). According to the Conectiv representative, it is not clear that 25 MW of demand reduction exists today. As stated earlier, the 11 MW number is based on Conectiv cycling the program in 1997.[65]

If the BPU continues the CEACP, it should consider having Conectiv report the costs and timetable of qualifying its CEACP as PJM capacity. If these costs are less than the net present value of the projected capacity value, then the BPU should consider having Conectiv participate in the PJM ALM program as the JCP&L and PSE&G programs do. The Conectiv representative provided a range of estimates to conduct the study to qualify for the PJM ALM between

[65] Based on CEEEP's conversations with Conectiv.

$100,000 and $300,000.[66] Streamlining the PJM approval process and having the utilities perform one coordinated evaluation of the capacity reductions may reduce these study costs.

Table 14: Additional Capacity Benefits of 11 MW - Baseline Capacity Forecast, Not Including the Costs of Satisfying PJM's Requirements 2005 – 2009 (in Thousands of Dollars)

| | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|
| Costs | | | | | |
| Total Costs | $ 7,193 | $ 7,325 | $ 7,140 | $ 7,068 | $ 7,093 |
| Costs Not Including Customer Payments | $ 2,823 | $ 2,991 | $ 2,842 | $ 2,806 | $ 2,867 |
| | | | | | |
| Benefits | | | | | |
| Capacity | $ 1,614 | $ 2,006 | $ 2,935 | $ 4,375 | $ 5,918 |
| Energy | $ 1,203 | $ 1,281 | $ 1,521 | $ 1,621 | $ 1,729 |
| Transmission and Distribution | Company estimates were not available | | | | |
| Market Efficiency and Transfers | $ 2,200 | $ 2,200 | $ 2,200 | $ 2,200 | $ 2,200 |
| TOTAL QUANTIFIABLE BENEFITS | $ 5,017 | $ 5,487 | $ 6,655 | $ 8,195 | $ 9,846 |
| | | | | | |
| Benefits Minus Costs | $ (2,176) | $ (1,838) | $ (484) | $ 1,127 | $ 2,753 |
| Benefits Minus Costs Not Including Customer Payments | $ 2,194 | $ 2,496 | $ 3,814 | $ 5,389 | $ 6,979 |
| | | | | | |
| NPV of Benefits Minus Costs (2005 to 2009) | ($1,179) | | | | |
| | | | | | |
| NPV of Benefits Minus Costs Not Including Customer Payments (2005 to 2009) | $16,701 | | | | |

### C. Option C: Selling the Program to a Third Party or Turning it Over to PJM

The benefits of the program are currently allocated to winning BGS bidders at no cost thereby reducing their capacity obligation and presumably resulting in lower BGS costs. Representatives of Reliant Energy, Inc. and PSEG Power, LLC were contacted. According to these representatives, the capacity value is quantifiable (along the lines performed by this study). The energy value is quantifiable in theory but may be too small to be considered as a meaningful part of a BGS supplier's bid. One representative noted that historical data reflects the performance of the program and therefore, to the extent that bidders base their bids on past data, their bids reflect the value of the program even if bidders cannot specifically identify the exact impact on their bid.

A limitation of having the utilities trying to maximize the capacity and energy value (and therefore increase the market efficiency benefit) of the program is that they do not have a strong financial incentive to do so. Having a third party, which may or may not be a BGS supplier, with this financial incentive may increase these values but this entity would not have the incentive to trigger the program for T&D reasons, which would reduce this potential benefit. A third party

[66] Based on CEEEP's conversations with Conectiv.

may be able to increase the amount of capacity eligible for the program by including the use of new technology and activate the program to provide additional energy savings.[67] The underlying value to a third party is the potential capacity and energy benefits of the program, which are reflected in the forecasted revenue streams in the cost-benefit analysis. As part of its continued stakeholder process on the CEACP, the Staff should consider soliciting additional information from third party providers, perhaps via the State Technologies Advancement Collaborative (STAC), who may be interested in operating this program or instituting a replacement.[68] If there is sufficient interest, the BPU may want to consider conducting a formal request for proposals to evaluate potential third party providers. In addition, multiple activation authorities may need to be considered so that if the program is operated by a third party, PJM and the utilities can still activated the program.

Another option, if legally permissible, is selling the program over to PJM. PJM, unlike a third party provider, would be expected to operate the program to maximize the efficiency and reliability of the PJM bulk power system. How PJM would structure and operate this program would need to be determined to see if it would result in a more cost effective program than it is now. PJM's management of the program, however, would not likely consider any avoided distribution system benefits in its decision-making process. Some number of activations, however, could be retained by each utility to allow it to trigger the program for local reasons. Another consideration would be that although the benefits are region-wide, New Jersey is now bearing the costs of the CEACP.

Besides its ALM program, PJM has an Economic Load Response Program and an Emergency Load Response Program. Both of these programs are for energy only, are due to expire at the end of the year, and are in the process of being reviewed by a PJM working group.[69] In the Economic Load Response program, the trigger is based on PJM clearing prices and load receives a payment when the program is triggered. As of the end of 2003, the Emergency Load Response program had only been triggered once. Load is triggered day-ahead and is paid $500/MWh. Participation is restricted to one of these three programs. The Staff should continue participating in and tracking these programs developments. Given the importance of capacity value in the benefits of the CEACP, switching the CEACP from the ALM program to one of the other demand response programs is unlikely to prove beneficial if alternatives do not provide capacity credits.

### D. Option D: Expand the Program

Any decision regarding whether the existing program should be expanded depends on whether the incremental benefits exceed the incremental costs.

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[67] Conectiv points out in its September 1, 2004 comments that direct load control demand response technologies are rapidly evolving from the ones deployed in the 1980s and early 1990s. See page 3 of their comments.
[68] Honeywell International and Comverge, Inc. participated in the July 29, 2004 stakeholder meeting. See the Discussion Summary of the July 29, 2004 Air Conditioning Cycling Program Meeting.
[69] Materials for this working group can be found at: http://www.pjm.com/committees/working-groups/dsrwg/dsrwg.html

Although existing capacity prices are low, which suggests that immediately expanding the program may not be cost effective, possible future developments, however, may make it desirable to expand the program. For example, changes proposed in the PJM capacity market could greatly impact the value of capacity and the resulting benefits from the program. The BPU should continue to monitor PJM capacity prices and consider expanding the program if capacity prices are expected to reach and remain at relatively high levels. (e.g., in the neighborhood of $150/MW-day, or higher). In addition, expansion of the program may be warranted in specific areas as a cost-effective means of avoiding transmission and distribution costs, such as in load pockets. If PJM reports changes in its market power assessment, expansion of the CEACP should be considered as a possible policy response in consultation with the PJM Market Monitor. Finally, the Staff should consider tracking technological and programmatic developments in appliance cycling programs for innovative approaches that may be cost-effective.

### E. Option E: Reducing the Cost of the CEACP

If consideration is given to discontinuing the CEACP, the costs of stopping and restarting the CEACP must be analyzed. Terminating the program would require customer outreach and costs associated with deactivating the infrastructure used to run the program. Moreover, if the BPU restarted the program in several years, then additional marketing costs and infrastructure reactivation costs would be required. The Staff should consider requesting utilities to provide such costs in order to assess the tradeoff between discontinuing the program with the possibility of restarting it with the associated re-start up costs versus costs of maintaining the program.

Ways to reduce the program's cost should also be evaluated before considering discontinuing the program. For instance, reducing fixed payments to customers for participating and increasing payments when appliances are cycled would reduce costs. Conectiv's program is an example of this approach. Care would have to be taken to maintain similar levels of program participation. The Staff should consider requiring the utilities to report alternative means of structuring payments and their likely affect on participation. If pursued, this approach would also require customer outreach to communicate and explain the new terms and conditions. During the October 29, 2004 meeting, some utilities raised possible issues of information technology (IT) limitations in changing payment options, for example, changing from payment per month to payment per cycling event.

Another option that has been raised in informal discussions is to discontinue part of the program, such as the water heater portion. Water heaters, if the PSE&G program is representative, are a small part of the CEACP. Central air conditioners constitute 96.6% of its program; water heaters only 0.84%.[70] Thus, discontinuing this part of the program is likely to provide little savings. According to a PSE&G representative at the October 29, 2004 meeting, PSE&G does not nominate water heaters to PJM and therefore does not obtain capacity credit for them.

[70] See response to Question 22. Only PSE&G provided this level of detail.

### F. Option F: Improving the Assessment of Transmission and Distribution Benefits

The lack of more specific estimates of benefits that were provided in response to the data request raises the issue of whether the CEACP programs are appropriately integrated into T&D planning and expansion practices. The Staff should consider determining whether the problem is that load response is not currently considered as an option far enough in advance to make a difference with respect to T&D expenditures. The BPU Staff should consider requiring utilities to study potential impacts of load control on circuits that may need future upgrades to see if it is less expensive than upgrades.

### G. Option G: Establishment of the Energy Price Trigger to Activate the CEACP

One important issue is the establishment of the energy price trigger to activate the CEACP. Table 16 presents the highest energy prices for the PSE&G zone for the Summers of 2000 through 2004. The rows in Table 16 are ranked from highest price during any hour of the day to lowest prices for all days in which at least one hour's price equals or exceeds $150/MWh. Highlighted hours indicate prices equal to or above $200/MWh; boxed hours are prices that equal or exceed $150/MWh. Since the prices in the JCP&L and Conectiv zones are highly correlated with those in the PSE&G zones, similar tables exist for the prices in these two other zones. Dates are shaded by year to indicate the frequency in a year that high prices occur.

Table 16: Summary of High PSE&G Zonal Prices ($/MWh) during the Summers of 2000 through 2004

| Date | 1100 | 1200 | 1300 | 1400 | 1500 | 1600 | 1700 | 1800 | 1900 | 2000 | 2100 | 2200 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20010809 | 156.79 | 763.10 | 955.04 | 969.98 | 970.11 | 970.04 | 970.12 | 970.15 | 721.49 | 366.03 | 946.40 | 338.00 |
| 20010808 | 147.08 | 182.96 | 386.10 | 907.67 | 885.77 | 887.11 | 945.92 | 944.48 | 307.04 | 123.50 | 170.14 | 109.18 |
| 20010807 | 101.32 | 168.00 | 187.78 | 444.48 | 921.90 | 152.10 | 253.61 | 388.74 | 155.40 | 102.50 | 338.00 | 78.99 |
| 20000626 | 66.21 | 72.47 | 93.14 | 108.68 | 235.13 | 848.21 | 280.70 | 81.82 | 70.93 | 70.80 | 58.81 | 66.28 |
| 20010725 | 219.07 | 445.01 | 555.44 | 815.12 | 814.72 | 811.55 | 806.15 | 498.98 | 125.25 | 126.91 | 124.93 | 82.20 |
| 20010810 | 205.93 | 537.00 | 814.10 | 728.59 | 274.35 | 36.80 | 37.72 | 51.15 | 38.87 | 36.43 | 139.35 | 48.06 |
| 20020723 | 65.41 | 72.86 | 109.98 | 148.01 | 203.54 | 226.38 | 702.19 | 90.40 | 44.09 | 38.39 | 38.75 | 35.57 |
| 20020729 | 68.43 | 56.08 | 75.03 | 74.73 | 151.57 | 693.49 | 289.44 | 172.40 | 137.25 | 63.15 | 90.44 | 80.81 |
| 20010724 | 87.61 | 175.40 | 168.40 | 191.77 | 295.80 | 554.64 | 610.63 | 369.86 | 272.89 | 97.92 | 134.45 | 106.68 |
| 20020814 | 75.83 | 97.07 | 331.05 | 267.42 | 397.36 | 125.43 | 127.45 | 94.80 | 71.23 | 54.57 | 48.77 | 44.12 |
| 20010628 | 84.77 | 103.15 | 127.92 | 198.77 | 264.62 | 389.53 | 214.00 | 137.94 | 114.91 | 61.69 | 75.04 | 54.10 |
| 20020802 | 74.34 | 86.37 | 103.37 | 288.12 | 141.06 | 148.16 | 167.00 | 145.71 | 122.31 | 75.09 | 69.10 | 46.54 |
| 20010608 | 32.67 | 28.64 | 25.69 | 35.76 | 37.26 | 34.10 | 75.94 | 250.45 | 137.25 | 91.23 | 84.78 | 39.20 |
| 20020813 | 47.65 | 54.21 | 95.39 | 181.85 | 148.36 | 215.08 | 224.85 | 92.52 | 106.26 | 44.77 | 75.08 | 46.34 |
| 20030815 | 128.25 | 177.38 | 140.95 | 206.51 | 127.69 | 148.41 | 131.78 | 114.14 | 105.01 | 81.42 | 92.76 | 73.46 |
| 20010710 | 61.70 | 61.40 | 70.94 | 103.50 | 206.28 | 83.27 | 79.41 | 82.35 | 99.29 | 77.45 | 76.95 | 61.50 |
| 20010806 | 91.44 | 133.52 | 172.67 | 171.40 | 194.02 | 164.67 | 179.10 | 187.73 | 145.95 | 101.17 | 139.92 | 78.36 |
| 20040820 | 119.08 | 131.13 | 136.33 | 159.61 | 185.83 | 152.00 | 118.79 | 92.30 | 61.55 | 55.39 | 57.65 | 48.10 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20040609 | 78.60 | 99.94 | 95.62 | 80.26 | 129.88 | 146.28 | 180.42 | 152.05 | 140.38 | 138.17 | 137.08 | 108.34 |
| 20040802 | 90.50 | 99.88 | 128.53 | 145.69 | 155.17 | 167.09 | 168.37 | 137.82 | 125.34 | 115.00 | 79.77 | 53.59 |
| 20020703 | 108.30 | 167.78 | 75.13 | 162.12 | 100.29 | 90.69 | 161.55 | 157.00 | 95.16 | 61.02 | 53.94 | 58.65 |
| 20040705 | 95.13 | 135.93 | 142.76 | 133.73 | 139.66 | 143.40 | 131.80 | 133.49 | 154.84 | 133.98 | 134.73 | 136.27 |
| 20040803 | 60.73 | 88.18 | 125.53 | 98.97 | 153.31 | 143.56 | 139.38 | 121.61 | 115.89 | 78.13 | 77.31 | 71.95 |
| 20040624 | 82.09 | 126.07 | 103.18 | 125.44 | 144.05 | 138.76 | 152.28 | 132.57 | 63.45 | 48.15 | 75.17 | 66.79 |
| 20040708 | 101.04 | 112.25 | 125.13 | 152.24 | 125.47 | 145.31 | 139.46 | 133.75 | 99.09 | 102.66 | 118.36 | 89.45 |
| 20010627 | 83.67 | 125.31 | 83.26 | 152.22 | 139.69 | 89.16 | 120.60 | 112.36 | 83.93 | 74.56 | 106.89 | 75.00 |
| 20030627 | 94.97 | 103.41 | 152.09 | 111.58 | 90.20 | 78.32 | 80.55 | 53.93 | 25.75 | 21.54 | 47.17 | 48.79 |
| 20040702 | 90.45 | 104.32 | 119.61 | 133.98 | 136.47 | 139.90 | 152.02 | 150.03 | 127.65 | 116.04 | 114.23 | 106.04 |
| 20040804 | 84.12 | 127.74 | 118.08 | 120.59 | 151.03 | 117.85 | 143.61 | 84.80 | 85.52 | 144.44 | 116.29 | 97.60 |

Notice that most of the very high prices occur in two summers, 2001 and 2002, out of five summers. Prices exceeded $500/MWh nine times in three of these five summers, but six of these times occurred in one summer. High prices can last up to twelve hours, although prices typically exceed $200/MWh for approximately four to six hours. Overall, there were sixteen days in which prices exceeded $200/MWh and twenty-nine days in which prices exceeded $150/MWh during these five summers.

During summers with tight demand and supply conditions, a higher price trigger, for instance at least $200/MWh, is appropriate. In summers with surplus, a lower price trigger may be appropriate, such as $150/MWh. An important consideration in setting the trigger is the attrition rate when the program is cycled. Longer and more frequent cycling may result in customers withdrawing from the program, which would reduce the capacity, energy, and T&D-reliability benefits of the program. Thus, there is a tradeoff between frequent cycling, which increases the energy value of the program, and attrition. Of course, given the random nature of prices along with changing market and regulatory conditions, future price patterns may not be similar to past price patterns. Consideration should be given to the establishment of a process that sets a price trigger for each summer based on market and T&D conditions consistent with the CEACP objectives.

## VI. Summary of Findings and Recommendations

The CEACP provides demand response in the PJM wholesale market. As the PJM market continues to develop, demand response is an important component to ensuring market efficiency. This report raises the question as to whether the CEACP as currently structured provides the most value for New Jersey, and puts before the Staff a range of options that may improve the efficacy of this program.

The one overriding recommendation is that whatever the structure of the program that Staff settles upon, the program should have clear objectives and consistent and coordinated implementation.

To provide in one place, a summary of findings, considerations and recommendations for Staff's review are listed below:

Findings

1. Conectiv's program does not participate in PJM's ALM and therefore does not qualify as capacity in the PJM capacity market.

2. Conectiv and PSE&G do not use the CEACP to reduce customers' energy costs.

3. All three utilities operate the program in a maintenance mode.

4. Capacity prices appear likely to remain relatively low through Spring of 2006, but at least some increase in capacity price above the current relatively low level appears inevitable.

5. Prices are likely to increase notably when CM falls below the 2 percent level.

6. PJM is in the process of making significant changes to its capacity market, which may significantly affect future capacity pricing. If adopted, these changes should increase the value of the CEACP but the amount of the increase cannot be determined at this time.

7. The energy and capacity market results were competitive in 2003 but there are potential threats to competition in both these markets.

8. Given that certain benefits are difficult to quantify, the cost-benefit analysis understates the total value of the program. That is, a negative cost-benefit amount does not in and of itself demonstrate that the program is not beneficial. The additional, difficult to quantify benefits should be considered by regulators in assessing the full value of the program and to inform future program direction.

9. For the baseline capacity price forecast, the net present value of the CEACP as it is currently operated is negative $15.5 million, although in one capacity price forecast scenario the net present value is positive $24.8 million.

10. Not including payments to customers participating in the CEACP as a cost but as a transfer payment, which is how previous analyses were conducted, results in a net present value of positive $2.4 million as the CEACP is currently operated.

11. The net present value of the benefits minus the costs from years 2005 through 2009 if the CEACP were to be operated similarly by all three utilities the net present value is negative $1.8 million due to the inclusion of 10% of the estimated transfer from producers to consumers amount as a benefit. Both the amount of this transfer and the percentage that is becomes a permanent benefit to consumers are difficult to quantify. In the year 2008, assuming that CEACP were to be operated similarly by all three utilities, the annual benefits begin to exceed the annual costs. Calculating the net present value of the CEACP beyond 2009 is difficult to do because it depends on the amount of

switches that would need to be replaced and on future capacity and energy prices. Assuming relatively few switch replacements beyond the ones assumed in the cost figures provided by the three utilities and higher capacity and energy prices than today, the CEACP could have a positive net present value over the next 10 to 15 year horizon.

12. A fundamental management difficulty with the CEACP is that its benefits cross industry sectors and include market benefits (capacity, energy, and market efficiency) and T&D.

13. According to BGS suppliers' representatives, the capacity value is quantifiable as part of their bid; however the energy value is quantifiable in theory but may be too small to be considered as a meaningful part of a supplier's bid.

14. A limitation of having the utilities trying to maximize the capacity and energy value of the program is that they do not have a strong financial incentive to do so.

15. Having a third party with this financial incentive may increase these values but this entity would not have the incentive to trigger the program for T&D reasons, which would reduce this potential benefit.

16. Given the importance of capacity value in the benefits of the CEACP, switching the CEACP from the ALM program to one of the other demand response programs is unlikely to prove beneficial if alternatives do not provide capacity credits.

17. Discontinuing the water heater portion of the program is likely to provide little savings.

18. Creating a new CEACP from scratch for Rockland Electric Co. would cost even more than expanding an existing program due to the additional program start-up costs.

<u>Recommendations for Staff's Review in Order to Improve the Cost Effectiveness of the CEACP</u>

1. The BPU needs to provide clear policy direction regarding the goals and operation of this program.

2. Conectiv should be required to report the costs of conducting a study to qualify for the PJM ALM program, and if those costs are below the expected benefits, then Conectiv should participate in the PJM ALM program.

3. The three utilities should coordinate their activation of the program to obtain larger energy and market efficiency benefits.

4. Whether and how the potential transfer from producers to consumers should figure into the evaluation of the CEACP is a decision that the Staff should confront.

5. If PJM reports increasing concerns of market power, expanding the CEACP should be considered as a possible policy response in consultation with the PJM Market Monitor.

6. Additional information, perhaps through the State Technologies Advancement Collaborative (STAC), from third party providers should be solicited who may be interested in operating this program or instituting a replacement. If such information indicates that third parties are a viable option, consideration should be given for conducting a formal request for proposals to evaluate potential third party providers and compare offers to the existing program.

7. Utilities should provide the necessary information in order to be able to assess the tradeoff between discontinuing the program with the possibility of restarting it with the associated re-start up costs versus costs of maintaining the program.

8. Utilities should be required to report alternative means of structuring payments and their likely affect on participation to reduce program costs, especially the feasibility and program impacts of replacing fixed payments to participating customers with payments based on when the program is activated.

9. Utilities should report how load response is currently considered as an option and whether it is considered sufficiently and far enough in advance to make a difference with respect to T&D expenditures.

10. Utilities should be required to study potential impacts of load control on specific circuits that may need future upgrades to see if load control is less expensive than upgrades. If so, the study should identify potential changes to the T&D planning and cost recovery processes needed for load control to be given proper consideration as an alternative to system upgrades.

11. PJM capacity prices should be monitored and if capacity prices are expected to reach and remain at relatively high levels. (e.g., in the neighborhood of $150/MW-day, or higher) consideration should be given to expanding the program.

12. Developments in the PJM capacity market, load response programs and the Mid-Atlantic Distributed Resources Initiative (MADRI) should be tracked and coordinated as applicable with the CEACP.

13. Technological and programmatic developments in appliance cycling programs should be tracked for innovative approaches that may be cost-effective.

14. Efforts should be pursued with PJM to lower the cost of conducting the studies needed by PJM to obtain capacity credit for individual utility appliance cycling programs.

15. The utilities should investigate the potential for performing a coordinated statewide evaluation of the program as required by PJM as a means of reducing the cost of verifying capacity credits.