IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S "BLUEPRINT FOR THE FUTURE," ESTABLISHING AN ADVANCED METERING INFRASTRUCTURE PROGRAM, DEMAND-SIDE MANAGEMENT INITIATIVES, UTILITY-PROVIDED DEMAND RESPONSE PROGRAMS AND OTHER PROGRAMS, AND REQUESTING BPU APPROVAL OF COST RECOVERY MECHANISMS RELATED THERETO	STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES BPU Docket No. ____________________ VERIFIED PETITION

ATLANTIC CITY ELECTRIC COMPANY (hereinafter referred to as "Petitioner," "ACE" or the "Company"), a public utility corporation of the State of New Jersey (the "State"), respectfully requests that the Honorable Board of Public Utilities ("BPU" or the "Board") approve cost recovery mechanisms and implementation authorizations, as appropriate, related to the Company's "Blueprint for the Future" (referred to herein as the "Blueprint" or the "Plan"). In support thereof, Petitioner states as follows:

1. The Company is engaged in the purchase, transmission, distribution and sale of electric energy to residential, commercial and industrial customers. ACE's service territory comprises eight (8) counties located in southern New Jersey and includes approximately 540,000 customers.[1]

2. In an effort to further the articulated goals of the New Jersey Energy Master Plan (herein, the "EMP") and assist the Board and the State in achieving their multi-faceted energy priorities, Petitioner, through its Blueprint, is prepared to institute a comprehensive complement

[1] ACE is part of the Pepco Holdings, Inc. ("PHI") family of companies. It is a wholly-owned subsidiary of Conectiv, a Delaware corporation, which is, in turn, a wholly-owned subsidiary of PHI, a Delaware corporation. PHI is an energy holding company engaged in regulated utility operations and sale of competitive energy products and services to residential and commercial customers. PHI companies deliver electricity and natural gas to more than 1.8 million customers in Delaware, the District of Columbia, Maryland, New Jersey and Virginia.

of demand response, advanced metering and energy efficiency programs for the Company's New Jersey customers. Each program and initiative is specifically set forth in the Blueprint attached as **Exhibit A** hereto. As proposed, the Blueprint will give Petitioner's New Jersey customers the tools, technology and information needed to reduce energy use and make more informed decisions about their energy use. It will also further the Company's ability to improve the operation and reliability of its electric distribution system.

3. Petitioner seeks the cost recovery authorizations requested herein to enable the Company to commit the necessary financial resources to make the Blueprint a reality for ACE's New Jersey customers. As described in summary fashion below, and in greater detail in **Exhibit A** (as supplemented and supported by **Exhibit B** and **Exhibit C** hereto), Petitioner is seeking authorization to:

(i) establish a separate Advanced Metering Infrastructure ("AMI") rate adjustment mechanism to recover the substantial costs associated with the installation of AMI and the associated meter data management system ("MDMS") that will enhance reliability and better serve Petitioner's customers;[2]

(ii) recover program costs for the Direct Load Control ("DLC") programs proposed in the Plan through the existing System Control Charge ("SCC") across all electric distribution customers;[3] and

(iii) to implement utility-provided energy efficiency and conservation programs and to recover costs related to those proposed low income conservation programs, solar programs, large customer Internet-based platform and other demand-side management

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[2] *See* **Exhibit A** at 60-61.

[3] *See* **Exhibit A** at 61-62.

("DSM") initiatives outlined in the Blueprint through the existing Societal Benefits Charge ("SBC").[4]

4. As stated in Paragraph 2 above, the Plan is designed to better enable customers to manage electricity usage through energy efficiency programs and offer an expanded opportunity to view and react to price signals in the market. With this enhanced customer access and interaction, it is expected that regional electricity wholesale capacity and energy prices will ultimately be reduced, particularly as a result of reduced peak demands.

A recent study prepared by The Brattle Group and commissioned by the Mid-Atlantic Distributed Resources Initiative ("MADRI") and the PJM Interconnection, LLC, found that a modest reduction in electricity use during peak hours would reduce energy prices by $57 million to $182 million annually in the Mid-Atlantic Region.[5] The study examined the effects of reducing electricity use by three percent during the highest use hours for five utility areas. It notes: "[m]ore widespread participation...and deeper curtailments would result in even greater price impacts...."[6] Finally, it underscores the importance of demand response to New Jersey and provides further support for the authorizations requested by the Company in this filing.

This Petition respectfully requests Board authorization to implement or expand existing surcharges, as detailed herein, that will enable the future cost recovery of these initiatives, programs and proposals. Such authorization will enable ACE to implement these programs, as well as provide necessary assurances to the investment community that costs incurred in

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[4] *See* **Exhibit A** at 62.

[5] *See* **Exhibit C**, "Quantifying Demand Response Benefits in PJM" (January 29, 2007) (herein, the "Brattle Report").

[6] *See* **Exhibit C** at 32.

developing and executing them will be fully recovered in a timely manner through appropriate mechanisms.

BLUEPRINT OVERVIEW AND SUMMARY

5. Petitioner's Blueprint involves a substantial investment in new technologies such as AMI, distribution automation, smart thermostats linked to the AMI system, and an improved communications network. Although the Company provides details on the components of the Plan in **Exhibit A**, a brief summary of Blueprint features and benefits is included below.

6. **Energy Efficiency/Energy Management Features**

Over the past several years, the rising cost of energy nationwide has affected all customers, who have only a limited ability to curtail their energy use and lower their energy costs. Despite this, the Company has provided customers with options to more efficiently manage their energy use. In 2006, for example, PHI and ACE launched the "Energy Know How Solutions" campaign. PHI invested over $1 million to implement state-of-the-art energy auditing software. This investment enabled ACE customers to go on the Internet and view data about their monthly bills in order to better understand how they use energy and what changes might reduce their overall costs.

The Blueprint is the next step in responding to customer concerns by giving them more robust and sophisticated energy efficiency tools to manage electricity consumption and reduce costs for electricity through reduced consumption. The Company's Plan includes utility provision of energy efficiency, conservation and demand response programs designed to influence consumer behavior in energy use to reduce on-peak energy demands, thereby reducing total electricity costs for New Jersey customers. The data and communications capabilities inherent in the advanced metering proposal that the Company outlines in this filing will give each customer a platform from which overall energy costs can be managed and controlled. ACE envisions that, in the future, the technology proposed herein will enable customers' appliances to receive and automatically react to real-time electricity prices. Some of these technologies will take time and need to be tested, but many are ready to be implemented immediately.

With the participation of the Board Staff, the Division of Rate Counsel ("Rate Counsel") and other interested stakeholders, the Company fully expects that a collaborative process will prove beneficial to the interests of all parties to assist Petitioner's customers to more thoughtfully and effectively manage their energy consumption and costs. The key components of this filing -- advanced metering, energy efficiency and demand response -- require key stakeholders to work collaboratively to identify best practices and achieve the best results for ACE customers.

A. Advanced Metering and Related Technology: Infrastructure

As stated in greater detail in **Exhibit A,** AMI will provide customers and the Company with more detailed and timely information on energy use. Petitioner proposes to replace 540,000 existing electric distribution meters with new computer-imbedded advanced meters by 2012. These advanced meters will allow the Company to collect and transmit customer information such as billing data, usage patterns, voltage levels and outage information, where the Company can process the data and use it to better serve customers. The AMI system can also be used to communicate directly with customers' thermostats and appliances and control the operation of this equipment based on energy prices. In the future, this same system will permit Petitioner to send information to customers, through a display in the customer's homes or to an Internet site, the price of electricity - either real time prices or day ahead pricing.

In addition to direct customer benefits, Petitioner anticipates service quality improvements from the AMI technology proposed herein, including the ability to remotely turn customers on or off (an advantage in areas with high turnover in occupancy), theft detection and -- as the Company will be able to monitor (as opposed to estimate) actual load -- more accurate service transformer and wire sizing. Customer restoration will be improved due to detailed information concerning the number and location of customers out-of-service being received from the advanced meters. Not only will this allow Petitioner to more quickly respond, but it will also help ACE pinpoint the location of the problem. Finally, there are added benefits to retail suppliers regarding access to immediate and detailed information regarding their customers' accounts. Petitioner estimates that the universal deployment of AMI to all New Jersey customers will cost approximately $128 million, depending upon system capability and configuration.

To expedite the roll-out of this technology, Petitioner has proposed the creation of an ACE AMI Advisory Group. Petitioner will share with the ACE AMI Advisory Group a more detailed plan supporting implementation of AMI technology.

The AMI component of the Plan includes preliminary cost estimates for the installation of remotely controllable programmable thermostats for residential and small commercial customers. These "smart thermostats" will permit the Company to install state-of-the-art technology designed to reduce residential and small commercial customer air conditioning load during periods of high electricity demand. The smart thermostats will serve as an easy mechanism for customers to control overall annual electric cooling *and* gas or electric heating costs.

B. AMI Communication Technology and Network Upgrades

Currently, there are two customer information systems and a variety of meter inventory management systems within PHI. One new PHI-wide system -- MDMS (an allocated portion of which will be attributed to Petitioner's New Jersey customers) -- will allow Petitioner to more efficiently and effectively use the greatly increased information coming from the automated meter reading system and new automated field devices. Implementation of the AMI facet of the Plan will improve the Company's communications network to accommodate the increased flow of customer and distribution system data to and from ACE's operational centers. A fixed communications network provides the most robust and secure communications platform for AMI and Distribution Automation. This network would take information to ACE's substations; from there it would travel over a private fiber network to Petitioner's main offices. All of ACE's transmission substations are currently served by fiber and the Company has plans to install fiber to selected distribution substations as well. It is important to leverage this network across all of ACE's technology investments, as it will support all applications if they share a common communications network. The New Jersey allocated cost for MDMS is estimated to be $2.8 million.

7. Demand-Side Management Initiatives

The Board's Office of Clean Energy ("OCE") has assumed primary responsibility for designing, implementing, administering and evaluating all publicly-funded electric-related energy efficiency and conservation programs since July 1, 2007, with the exception of the low income program known as "Comfort Partners." ACE has more than 15 years of experience in the provision of demand-side management programs to New Jersey customers and is prepared to work closely with the Board to design and implement utility-provided energy efficiency and conservation programs that would augment or supplant OCE's programs.[7] Petitioner respectfully submits that direct utility involvement in the design and management of these programs will be an essential part of the activities needed to meet the ambitious energy consumption reductions desired by New Jersey policymakers and expected in the final version of the EMP.

Although described in greater detail in **Exhibit A**, Petitioner's Plan supports the introduction of four new demand-side management programs: (a) a residential/small commercial remotely controllable smart thermostat program to permit the utility to reduce summer air conditioner load during peak periods;[8] (b) a dynamic pricing program that would offer all Basic Generation Service ("BGS") customers a default or optional critical peak pricing or critical peak rebate rates; (c) an Internet-based demand response platform to support larger-size customer participation in the PJM demand response program; and (d) a Comprehensive Energy Saving Pilot ("CESP") Program that will seek to maximize individual customer electric grid-sourced electricity consumption through an integrated approach consisting of the installation of energy efficiency and conservation measures, installation of renewable on-site generation, installation of

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[7] Petitioner continues to operate a residential air conditioner/heat pump, water heater and electric motor control program known as the "Peak Savers Club." During the summer of 2007, more than 24,000 residential and small commercial New Jersey customers participated in this program, providing more than an estimated 17 MW of peak electricity demand reduction. From 2001 through 2006, ACE's total lifetime energy efficiency savings achieved by historic utility energy efficiency and conservation programs exceeded 300,000 MWh.

[8] The DLC program proposed in the Blueprint is consistent with a proposal that was made by the Company in August 2007. On May 23, 2006, the Board issued an Order approving a settlement agreement regarding the future operation of existing New Jersey DLC programs. New Jersey utilities were directed to work with Board Staff and Rate Counsel to evaluate existing utility DLC programs and recommend the "future direction" of such programs. On June 7, 2007, in conformance with the May 2006 Order, ACE, Jersey Central Power & Light Company and Public Service Electric and Gas Company filed a proposal entitled "New Jersey Direct Load Control Program Proposal" to expand their existing DLC programs. That filing stated that each utility would submit its company-specific plan to the Board for consideration. On August 20, 2007, ACE filed its Company-specific plan in connection with BPU Docket No. EO06040297. Petitioner's filing provided program details for 2008 and stated that proposed program details for the period 2009 through 2012 would be presented at a later date. Hence, this filing. (*See* ACE, August 20, 2007 Filing at 3.) As of this date, the Board has not acted on Petitioner's August 20th DLC filing.

demand response enabling equipment, and, over time, integration of installed measures with a dynamic electricity pricing structure supported by AMI deployment. Preliminary utility-incurred projected pilot costs for the CESP Program are estimated to be $5 million.

These programs, coupled with appropriate investments in technology, will provide the tools for all of Petitioner's electric distribution customers to manage their electricity costs, including reducing the cost of energy consumption. More detail, including cost estimates and cost benefit analyses, is provided in **Exhibit A**.

8. Petitioner has also proposed several low income programs that are intended to buttress ACE's continuing commitment to meet the needs of low income electricity customers.[9]

9. The Company's Plan also seeks to establish two programs that will result in the installation of 3.5 MW of additional photovoltaic distributed generation capacity over a five year period in New Jersey. These installations will help achieve the State's aggressive solar renewable portfolio standards goal. The installations are expected to provide additional generation capability during periods of high summer peak electricity demand, while simultaneously reducing power plant air emissions.

10. **Cost Recovery Mechanisms**

Petitioner's Blueprint is an aggressive, forward-thinking Plan that has been designed to provide real and substantial benefits to ACE's New Jersey customers and to assist the State in achieving its ambitious EMP goals. To implement the Plan and achieve its many benefits, ACE will be required to make significant capital and financial commitments. Such commitments require companies, regulators and other interested parties to implement innovative, yet appropriate, regulatory and cost recovery approaches.

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[9] *See* **Exhibit A** at 50-52.

11. To facilitate the timely cost recovery of prudently incurred AMI expenditures and provide adequate cash flow for the deployment of new technologies and innovative programs, Petitioner has proposed cost recovery mechanisms for each of the initiatives proposed herein. *See* Paragraph 3, *supra* and the "WHEREAS"paragraph, *infra.*

In one case, Petitioner has requested that the Board create a base rate adjustment mechanism -- or surcharge -- that would permit ACE to recover capital costs associated with AMI on a timely basis.[10] In another -- Petitioner's DLC program proposals -- ACE proposes to recover program costs through the existing SCC. Petitioner further requests that consideration be given to a cost recovery approach that removes electric distribution utility financial disincentives related to the promotion of DSM, energy efficiency and renewable programs and better aligns the financial interests of the Company and its shareholders with the interests of New Jersey consumers and policymakers. Mindful of the myriad, competing priorities in New Jersey's energy and environmental landscape, Petitioner respectfully submits that this mechanism -- referred to as the "Bill Stabilization Adjustment" ("BSA") -- is ripe for discussion with, and favorable consideration by, the Board.

12. Under PHI's proposals in other jurisdictions, individual customer distribution charges are related to consumption, but overall distribution charges are adjusted at agreed-upon

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[10] A traditional utility cost recovery approach would involve the filing of an electric base rate case. This mechanism has the significant disadvantage of delaying a utility's cost recovery for significant capital cost projects. Base rate cases can also have an adverse impact upon a utility's cost of capital.

intervals so that utility earnings remain constant, regardless of total throughput.[11] Distribution rate decoupling is supported by the National Action Plan for Energy Efficiency Coalition, the Clinton Global Initiative, the Natural Resource Defense Council and MADRI.

13. Petitioner submits that the BSA is fiscally sound and consumer sensitive because, as designed, it stabilizes distribution revenue fluctuations resulting from unanticipated changes in usage and ensures that the utility only recovers the Board-approved level of distribution costs.

The BSA creates an adjustment to customers' bills that reflects differences between Board-approved delivery revenue levels and actual delivery revenues. This would be a financial benefit for the consumer who would pay only the amount determined by the Board as required to provide safe, adequate and reliable distribution service. It would be a benefit to the electric utility shareholders because the utility would maintain a stable revenue stream year-to-year consistent with the costs of providing safe, adequate and reliable service. An electric utility's costs for providing services are generally fixed, regardless of the volume of sales that the distribution company delivers to its customers. The BSA provides for a matching of revenues in quarterly periods with the corresponding amounts that the Board has approved as adequate compensation for providing service. Thus, the customer *and* the electric distribution utility's shareholders are better off when a stabilization mechanism is in place. A cost recovery methodology that severs the link between increased sales of electricity and increased profits

[11] PHI's Maryland distribution utilities, Potomac Electric Power Company ("Pepco") and Delmarva Power & Light Company ("Delmarva"), recently received approval of the Maryland Public Service Commission to decouple distribution rates from energy throughput. (Maryland Commission Order No. 81517, Formal Case No. 9092, issued on July 19, 2007 and Maryland Commission Order No. 81518, Formal Case No. 9093, issued on July 19, 2007.) Pepco has proposed a similar mechanism in its District of Columbia electric base distribution rate case. (District of Columbia Formal Case No. 1053.) Delmarva has recommended a similar proposal in Delaware. (Delaware PSC Docket No. 05-304.)

eliminates the potential for utilities to unenthusiastically promote demand-side resources or energy efficiency programs.[12]

14. In light of the above and the rationale reflected in the attached Plan, Petitioner respectfully requests that the Board establish a working group or other form of collaborative in order to explore instituting the BSA or similar proposal in New Jersey that separates electric distribution rates from energy throughput.

15. Communications and correspondence regarding this matter should be sent to Petitioner's counsel at the following address:

Philip J. Passanante
Assistant General Counsel
Atlantic City Electric Company - 89KS42
800 King Street, 5th Floor
P.O. Box 231
Wilmington, DE 19899-0231
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with copies to the following representatives of the Company:

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[12] It is important to remember that a decoupling mechanism would only be applicable to the *distribution* portion of the customer's bill. Currently, the distribution portion accounts for approximately 18% of the average residential bill. The supply portion of the bill, which accounts for almost 60%, would not be subject to the mechanism.

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Stephen L. Sunderhauf
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WHEREFORE, the Petitioner, **ATLANTIC CITY ELECTRIC COMPANY,** respectfully requests that the Honorable Board of Public Utilities, consistent with the analysis expressed in the Blueprint Plan attached hereto, issue an Order as follows:

A. With respect to Petitioner's proposed deployment of AMI technology,

1) **establish** and adopt an AMI adjustment mechanism in the form of an AMI surcharge, which will permit ACE to recover capital costs associated with the installation of AMI on a timely basis and permit the Company to recover, on an accelerated basis, the cost of existing meters that are being retired; and

2) **establish** an ACE AMI Advisory Group so that Board Staff and Rate Counsel can be kept apprised of the progress, status, components, development and implementation of Petitioner's AMI initiatives; and

B. with respect to Petitioner's proposed DLC program, **approval** to recover program costs through the existing SCC, as outlined in the Plan, with adjustments on January 1st of each year through an annual reconciliation/cost recovery filing; and

C. with respect to Petitioner's proposed low income initiatives, programs to install additional photovoltaic equipment on Company-owned and/or leased buildings and substations and qualified customer property, establishment of an Internet-based platform for load curtailments, and CESP Program, **approve** recovery of such costs through the existing SBC. The Company will reconcile applicable program costs on an annual basis.

D. Petitioner further requests that it be permitted to design, administer and manage utility-provided demand-side management programs that would augment or, with Board approval, supplant programs currently administered by the Board, through the OCE and the recovery of these program costs through the SBC.

E. Petitioner further, finally and respectfully requests that the Board establish a working group or other collaborative for the purpose of examining and implementing alternative approaches to traditional electric distribution cost recovery, which, like the BSA, preserve appropriate Board oversight over utility rates, but reduce the volatility in the distribution charge component of customers' bills.

Respectfully submitted,
ATLANTIC CITY ELECTRIC COMPANY

Passanante

Dated: November 19, 2007

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STATE OF NEW CASTLE)
)SS:
COUNTY OF DELAWARE)

AFFIDAVIT OF VERIFICATION

J. MACK WATHEN, being duly sworn, upon his oath, deposes and says:

1. I am the Vice President of Regulatory Affairs of Atlantic City Electric Company ("ACE"), the Petitioner named in the foregoing Verified Petition, and I am duly authorized to make this Affidavit of Verification on ACE's behalf.

2. I have read the contents of the foregoing Verified Petition. I verify that the statements of fact and other information contained therein are true and correct to the best of my knowledge, information and belief.

J. Mack Wathen
J. MACK WATHEN

SWORN TO AND SUBSCRIBED before me this 16th day of November, 2007.

Julia R. Swintek/Reilly
Julia R. Swintek/Reilly
Notary Public
My Commission Expires: April 30, 2009

JULIA R. SWINTEK
NOTARY PUBLIC
STATE OF DELAWARE
My Commission Expires April 30, 2009

EXHIBIT
A

IN THE MATTER OF **APPLICATION AND PETITION OF ATLANTIC CITY ELECTRIC COMPANY'S "BLUEPRINT FOR THE FUTURE," ESTABLISHING AN ADVANCED METERING INFRASTRUCTURE PROGRAM, UTILITY-PROVIDED DEMAND RESPONSE PROGRAMS, AND OTHER PROGRAMS AND REQUESTING BPU APPROVAL OF COST RECOVERY MECHANISMS RELATED THERETO**	**STATE OF NEW JERSEY** **BOARD OF PUBLIC UTILITIES** **EXHIBIT A**

Dated: November 19, 2007

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I. INTRODUCTION

This document contains the details of the Atlantic City Electric Company's ("ACE", "the Company") Blueprint for the Future Plan ("Blueprint Plan," "Plan"), which is being introduced across all of Pepco Holdings Inc.'s ("PHI") electric distribution companies and their various jurisdictions.[1] The purpose of the Company's Blueprint for the Future is to set forth ACE's comprehensive vision of the future to achieve the following:

- To support the New Jersey Energy Master Plan and to assist the Board of Public Utilities ("Board"), Governor Corzine, and other New Jersey state policymakers achieve their publicly articulated aggressive energy efficiency and renewable electricity generation goals.
- To assist ACE's customers to reduce and manage their energy costs.
- To continue to reliably distribute electricity to ACE customers.
- To increase transmission import capability into southern New Jersey to meet current and projected needs and to support additional renewable generators.
- To improve the operation of the electric distribution system through the deployment of new technology that provides increased monitoring of both the distribution system and each customer's electric service.
- To improve electric distribution service quality.
- To reduce electric distribution operations and maintenance expense.

[1] PHI is the holding company of Atlantic City Electric Company, Delmarva Power & Light Company, and Potomac Electric Power Company. Collectively these companies deliver electricity to customers in New Jersey, Delaware, Maryland, the District of Columbia, and Virginia. In addition, Delmarva delivers natural gas to customers in Delaware. The Delmarva Power & Light Company is selling its Virginia service territory to A&N Electric Cooperative and Old Dominion Electric Cooperative, subject to receipt of regulatory approval.

- To reduce power plant air emissions by reducing overall electricity use.
- To increase the installation of photovoltaic renewable generators and to maintain their long-term reliability.
- To support customer adoption of new, environmentally friendly, plug-in vehicles, by supporting dynamic pricing to permit vehicles to be charged during less costly night time hours.
- To increase job opportunities within New Jersey.
- To work collaboratively with the Board of Public Utilities and other New Jersey electricity market stakeholders to establish the regulatory framework necessary to make these initiatives a reality.

The critical components of ACE's Blueprint Plan are: 1) cost-effective demand response programs designed to reduce electricity demand during periods of high market prices;[2] 2) utility provision of energy efficiency and conservation programs directly to ACE customers to either augment or in lieu of the programs currently administered by the Board's Office of Clean Energy; 3) deployment of an advanced metering infrastructure system for all ACE customers; 4) ACE ownership and installation of photovoltaic systems directly connected to Company facilities; 5) ACE provided financing, installation, and maintenance of New Jersey residential and commercial photovoltaic installations; 6) proposed cost recovery mechanisms that permit ACE to make the substantial utility investments necessary to implement the Blueprint Plan; and

[2] The Company's and competitive suppliers' ability to offer new time differentiated rates, such as critical peak pricing, will be supported by the deployment of an AMI System. These pricing options are expected to significantly support appropriate demand response activities.

7) ACE's willingness to work collaboratively with the Board and New Jersey electricity market stakeholders to make these proposals a reality as rapidly as possible.

In addition to providing direct customer savings, over time the resulting reductions in peak electricity demand are expected to help the Company maintain the reliable supply of electricity in southern New Jersey to serve demand. New Jersey's increasing reliance on limited regional transmission system capabilities for imports of electricity is a significant concern of the Company. As a result, PHI has designed and proposed a major new transmission line into southern New Jersey. Additional energy efficiency improvements and increasing reliance on renewable electricity generation are expected to help reduce power plant air emissions and associated greenhouse gases.

On September 27, 2007 former President Bill Clinton announced on behalf of the Clinton Global Initiative[3] ("CGI") the commitment of PHI and seven other U.S. utilities[4] to work to reduce over 29 million tons of greenhouse gas emissions, equivalent to the emissions of 6 million cars or 25,000 MW of peak demand over the next ten years. The eight utilities are committed to working with state regulators to enable them to make the required substantial investments in energy efficiency related products and services to achieve these air emissions reductions and to improve the productivity of the electricity sector. PHI and the other companies, together with the Edison Electric Institute, have agreed to form the Institute for Electric Efficiency ("IEE").

[3] CGI is a non-partisan catalyst for action lead by former President Bill Clinton, bringing together a community of global leaders to devise and implement innovative solutions to some of the world's most pressing challenges. CGI has approximately 1,000 members, diverse and influential leaders from all over the world, who make tangible commitments to take action to address specific global challenges.

[4] The eight electric utilities are Pepco Holdings, Inc., Consolidated Edison, Inc., Duke Energy Corporation, Edison International, Great Plains Energy, Inc., PNM Resources, Inc., Sierra Pacific Resources, and Xcel Energy, Inc.

IEE will promote the sharing of information, ideas, and experiences on effective means of delivering energy efficiency.

Each year, ACE conducts an extensive customer satisfaction survey of its residential customers. This survey outlines key drivers of customer satisfaction. Through the implementation of the technologies and programs contained in this filing, many of the key drivers of customer satisfaction can be positively impacted. For example, primary and secondary customer satisfaction drivers that will be positively impacted include Reliability and Restoration performance, Energy Information, Overall Customer Service, and a number of related areas. Company annual survey findings also indicate that customer satisfaction is driven by ACE's ability to address customer problems, offer energy information/conservation solutions, demonstrate environmental stewardship, offer billing options and have customer service representatives who are knowledgeable about energy management and related solutions. Implementation of our Blueprint will enhance customer experience when interacting with ACE.

Over the past several years the rising cost of energy has affected ACE's customers. Recently, the Company has provided its customers with options to more efficiently manage their energy use. Last year PHI and ACE launched the "Energy Know How" campaign. PHI and ACE invested over $1,000,000 to implement state of the art energy auditing software. This investment now enables ACE's residential and commercial customers to go on the internet and view data about their monthly bills to better understand how they use energy and what changes might reduce their overall costs.

New metering technology that supports time differentiated pricing options is expected to improve customers' ability to manage their electricity use so that overall energy reductions can be readily obtained. In addition, these pricing options will provide electricity market financial incentives for the installation of renewable generation technologies capable of producing energy during periods of high electricity demand and accelerate customer adoption of plug-in vehicles. The new metering technology will help ACE integrate these technologies into the grid effectively. The increasing use of plug-in vehicles and renewable generation technologies will help to reduce the nation's dependence upon foreign sources of energy, improve regional air quality, and reduce future quantities of greenhouse gas emissions.

An important element supporting ACE's recommended demand response programs is the deployment of an Advanced Metering Infrastructure ("AMI") System capable of providing hourly energy consumption data for all customers that can support voluntary pricing options, whereby electricity prices for customers more closely track wholesale electric energy and capacity prices. In this manner, customers will be incented to reduce their electricity consumption during high priced periods. In addition to helping participating customers manage their electricity bills, the optional rate structures will help to place significant downward pressure[5] on regional wholesale electric energy and capacity prices during peak load periods, thereby reducing future electricity supply costs for all New Jersey consumers.

ACE has designed the rollout of its proposed remotely controllable smart thermostat deployment to be integrated into the deployment of its proposed AMI System for the following reasons: First, the advanced metering system and the smart thermostats ("smart stat") can be designed in a manner whereby the communications infrastructure is shared by both systems –

[5] A recent study issued on January 29, 2007, entitled "Quantifying Demand Response Benefits in PJM," which was prepared by The Brattle Group on behalf of the PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative ("MADRI"), has quantified the significant reduction in regional wholesale electricity market prices that occur as a result of a 3 percent reduction in electricity load. The study found that curtailing 3 percent of the BGE, Pepco, PECO, Delmarva, and PSEG load during the highest 133 to 152 load hours would reduce energy prices during those hours by 5 to 8 percent or $8 to $25 per MWh. The price benefits for the MADRI states are estimated to be $101.9 million annually under normal weather conditions for a three percent reduction.

helping to reduce the total cost of the system. Second, it may be possible to install a system where the advanced meter and the smart thermostat can communicate directly with one another to enhance future program opportunities. Third, a critical problem with existing air conditioner cycling programs, including ACE's Peak Savers Club Program, is the inability to determine remotely whether cycling equipment is functioning properly – a problem that is remedied by the integration of a smart thermostat system with the planned AMI System. Fourth, the value to an individual customer of a smart thermostat is significantly enhanced if the consumer receives an hourly market based price signal that directly rewards the participating customer for achieved load reductions. Any delay in deploying an advanced metering system in ACE's service territory will delay ACE's ability to create the optimal smart thermostat program to manage residential and small commercial customer air conditioner load – the primary driver of summer peak electricity demand.

It is important to note that the deployment of an advanced metering system will help to support all demand-side management ("DSM") program efforts. Customers will learn when and how they use electricity, DSM program administrators will be able to refine DSM program design for individual customers, DSM evaluators will have greater certainty that savings have been achieved, and electricity suppliers will be able to reduce their hedge premium required to serve customers without interval data. Adoption of optional or default innovative pricing options for ACE customers will help customers directly capture the benefits of reducing their electricity demand during high priced periods through energy efficiency improvements, demand response, and the installation of distributed generation. Additionally, the availability of hourly consumption data for all customers greatly improves the Company's ability to optimally design and operate the electric distribution system.

ACE looks forward to implementing its Blueprint Plan over the coming years and to working collaboratively with the Board and New Jersey electricity market stakeholders on its implementation of the Blueprint initiatives. The Company's leadership and employees are strongly committed to this initiative that is designed to assist our customers to manage and reduce their electricity use, reduce future air emissions from power plants, and help achieve New Jersey policy makers' energy consumption reduction and renewable generation goals.

II. ADVANCED METERING AND RELATED TECHNOLOGY[6]

ACE plans to deploy an AMI system[7] and the associated meter data management system for all of its New Jersey electric customers as part of an overall PHI AMI deployment plan to better serve its electric and gas distribution customers. ACE's affiliated electric distribution company, Potomac Electric Power Company ("Pepco"), submitted a similar plan to the District of Columbia Public Service Commission on April 4, 2007. Pepco submitted a similar plan to the Maryland Commission on March 21, 2007 that is expected to result in the installation of AMI equipment for all Pepco Maryland electric distribution customers. ACE's affiliated electric distribution company, Delmarva Power & Light Company ("Delmarva Power"), submitted a similar plan to the Delaware Commission on February 6, 2007 and to the Maryland Commission

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[6] The Board initiated a Transitional Rate Design Working Group on March 14, 2006 to examine issues related to rate design and smart metering as a result of the U.S. Energy Policy Act of 2005. ACE filed its comments on March 29, 2006.

[7] ACE agrees with the electric AMI system definition developed by the Federal Energy Regulatory Commission Staff:

> Advanced metering is a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point. (Federal Energy Regulatory Commission Staff Report entitled "Assessment of Demand Response & Advanced Metering," August 2006, p. 17.)

on March 21, 2007 that will result in the installation of AMI equipment for all of Delmarva's Maryland and Delaware electric distribution customers and Delmarva's Delaware gas distribution customers. ACE recognizes that the costs of such a deployment are significant; however, the resulting benefits to ACE's New Jersey electric customers will exceed those costs.

Due to the magnitude, complexity, and importance of this project, ACE recommends that the Commission establish an ACE AMI Advisory Group comprised of representatives of ACE, the Board Staff, the Division of Rate Counsel ("Rate Counsel") and any other parties the Board deems appropriate. ACE will share its AMI project plans with the AMI Advisory Group and provide a copy of its detailed AMI project plan to the Board. ACE's technical staff will be responsible for the evaluation, vendor negotiations, and final vendor selection. After vendor selections are made, ACE will share its detailed implementation plan and refined project cost estimates with the Advisory Group. The detailed implementation plan will also be shared with the Board.

Due to the significant utility costs expected to be incurred and the type of utility asset, ACE recommends that the Board establish an AMI specific cost recovery mechanism in the near-term. Approval of the proposed cost recovery mechanism will permit the Company to recover its prudently incurred AMI capital expenditures over an appropriate time period that is fair to both ACE customers and PHI shareholders.

The significant benefits of AMI deployment have recently been recognized by other utilities and state regulatory commissions. Pennsylvania Power & Light Company completed the installation of 1.3 million electric meters in 2004 for all of its electric distribution customers. Southern Company (4.5 million electric meters) and Detroit Edison (3 million electric meters) have received Commission approval to replace all of their meters with an AMI system and are currently in the vendor RFP phase of this work. The Pacific Gas & Electric Company has received California Commission approval for universal deployment of an AMI system and is currently deploying 5.2 million electric meters and 4.1 million gas meters. Southern California Edison Company (5.1 million electric meters for an estimated cost of $1.3 billion) submitted a filing on December 21, 2006 to the California Commission proposing to initiate AMI pre-deployment activities leading to full deployment beginning in early 2008. San Diego Gas & Electric Company has agreed to revise its AMI deployment plan for all of its customers (1.3 million electric meters and 800,000 gas meters) and is awaiting approval of a settlement agreement. On January 23, 2006, the Baltimore Gas & Electric Company filed with the Maryland Commission for approval of the deployment of an AMI system beginning in 2007. The Maryland Commission Order No. 81637, Formal Case No. 9111, issued on September 28, 2007 recognized several of the important benefits of AMI: "Of course, we also recognize that the peak load reductions occasioned by AMI and an appropriate rate structure will provide significant benefits in terms of maintaining reliable service, as well as reductions in capacity and energy costs." (Order, p. 4).

ACE has prepared a detailed financial business case supporting its AMI System deployment. A copy of the business case, entitled "Advanced Metering Business Case Including Demand-Side Management Benefits" is provided as **Exhibit B**. The financial benefits of AMI that have been estimated by the Company are monetized distribution utility operational savings and expected reductions in electricity commodity costs for ACE consumers. Consumers receive additional benefits through improvements in electric distribution service. The value of these improvements has not been estimated by ACE due to their non-pecuniary nature. ACE retained the Brattle Group[8] to estimate the peak demand reduction resulting from AMI deployment through AMI supported dynamic pricing, such as critical peak pricing, and AMI enabled reduction in New Jersey customer electricity commodity costs. A copy of the Brattle report, entitled "Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," is attached as **Exhibit C**. ACE's business case indicates that the deployment of an AMI System is expected to result in no additional total electricity costs to ACE's customers under conservative assumptions and is reasonably likely to result in financial benefits if significant numbers of customers are placed on dynamic prices. The New Jersey state-wide net present financial benefits achieved by ACE's AMI enabled demand response are expected to range between $102 million to $218 million if dynamic pricing is widely adopted by ACE customers.[9] ACE believes that these estimates of financial benefits are conservative and therefore, reasonably likely to be exceeded. The Brattle Group projects that additional peak demand response capability will exceed 145 MW if dynamic pricing enabled by AMI deployment is widely adopted within the ACE service territory.

The Company plans to deploy an AMI System within the ACE service territory for the following reasons: 1) the cost of electricity has risen significantly within the Mid-Atlantic region in recent years thereby greatly increasing the need for detailed consumption data for all ACE New Jersey electricity customers; 2) AMI deployment will provide significant ACE New Jersey electricity customer benefits and overall New Jersey customer benefits; 3) AMI equipment is

[8] The Brattle Group was also retained by PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative ("MADRI") during 2006 to estimate the financial benefits related to the introduction of additional demand response within the PJM Mid-Atlantic electricity market.

[9] The net present value benefits to ACE's customers alone range between $100 million to $126 million. *See* Table A.1, PHI Brattle Report, Exhibit C, p. 64.

currently available from vendors at a reasonable cost, but availability may become more limited in the future as additional utility AMI deployments are initiated; and 4) metering technology has evolved sufficiently to make this practicable.[10]

A. AMI Infrastructure

The Company intends to implement an AMI System and the associated MDMS for all of its New Jersey electric customers as part of an overall PHI-wide deployment beginning with the planning phase during 2007. The Company's adoption of this approach is based upon its recent completion of a multi-year effort to examine the technical and operational aspects of AMI Systems, further development of AMI technology and supporting systems, and the increasing benefits associated with providing New Jersey consumers with additional information about their electricity consumption in order to help to manage energy bills.

The near-term tasks for ACE's New Jersey AMI project include the following:

- Assess Customer/Utility Requirements;
- Establish Recommended Systems Capabilities;
- Review Available Technology and Communications Systems;
- Participate in Vendor ACE RFP Development;
- Develop Detailed Project Plans;

[10] ACE's affiliated company, Pepco is currently working with the Smart Meter Pilot Program, Inc. to implement a smart metering pilot program in the District of Columbia during 2007. This pilot was initiated as the result of the Pepco/Conectiv merger settlement agreement, whereby the Company agreed to contribute $2 million towards a smart metering pilot initiative. A portion of pilot program participants will receive a smart thermostat to help them to reduce their summer air conditioning load during high priced periods. The purpose of the District of Columbia pilot is to test customer response to different rate options and billing statements rather than to test any AMI or smart thermostat technology. The pilot is designed to test residential customer response to three rate options based upon Pepco Zonal day-ahead PJM Locational Marginal Prices: 1) hourly pricing, 2) critical peak pricing, and 3) critical peak rebates. The results gathered from the study will be used by PHI to develop appropriate rate options for customers that will be supported by the Company's universal AMI deployment plan.

- Identify Project Risks;
- Refine Project Cost Estimates;[11]
- Prepare Detailed ACE New Jersey AMI Implementation Plan; and
- Install Information Technology Systems and Associated Interfaces;

B. AMI Project Timeline

PHI is developing an AMI implementation timeline applicable for all of its electric distribution companies that will result in completion of all AMI meter installations by 2012.[12] At this time, ACE New Jersey AMI meter installations are expected to begin during 2011 and be completed by 2012. PHI will optimize the installation of AMI equipment in a manner that helps to minimize capital and labor related installation costs and that is achievable with the expected availability of required labor and AMI equipment. ACE anticipates that as AMI metering equipment is installed some of the benefits related to AMI will be available to each customer that receives the new metering equipment.

C. AMI Implementation Cost

The Company estimates that the cost of a universal deployment of AMI for all of its approximately 540,000 New Jersey electric distribution meters will be approximately $128 million, depending upon system capability and configuration. The major components of this cost include new smart meters with household communication links, communication equipment, and the build out of the local area network ("LAN") and the wide-area network ("WAN"), and supporting software systems. It is important to recognize that ACE will not be able to provide

[11] Final project cost estimates will be available after vendor selection and negotiations have been completed.

[12] A limited number of meters may require additional installation time due to access or location problems.

refined project cost estimates until vendor selection and contract negotiations have been completed. The purchase and installation of a MDMS will be required to process the significant quantities of meter data collected through the AMI System. Based upon full PHI AMI implementation, the ACE New Jersey allocated cost for the MDMS is estimated to be $2.8 million.[13] Potential additional expenses that are not included would be incurred for interfaces to Control Center outage management software, upgrades to the utility settlement system, future customer information system upgrades or replacement, customer educational materials, utility personnel training, and any deployed demand response technology.

ACE's demand-side management response program proposals contained in this filing include preliminary cost estimates for the installation of remotely controllable programmable thermostats for residential and small commercial customers. These smart thermostats will permit ACE to install state of the art technology designed to reduce residential and small commercial customer air conditioning load during periods of high electricity demand. The smart thermostats will serve as an easy mechanism for customers to control both their overall annual electric cooling and gas or electric heating costs.

D. AMI Communication Technology

The primary component of an AMI System is the communication system. At this time, five alternative communication methods exist: power line carrier, broadband over power line, fixed radio, cellular, and landlines. Under power line carrier, data pass through the electric distribution network and are gathered at electric distribution substations for transmittal back to the utility. Broadband over power line ("BPL") permits an even greater quantity of digital data

[13] The total cost of MDMS is estimated to be $10 million. Ultimately, PHI proposes to spread this cost across all of its electric distribution companies and the jurisdictions that adopt the Blueprint for the Future.

to be passed through the electric distribution network; however the data are effectively blocked by distribution transformers necessitating the installation of additional equipment to bypass each transformer. BPL systems are more expensive to install than other AMI communication systems due to the additional required equipment. PHI has participated in a BPL test in Montgomery County, Maryland for several years.

Radio based systems directly communicate with individual meters. Mesh systems permit meters that are unable to directly communicate with the radio tower due to insufficient signal strength, to communicate with nearby meters that have the capability of passing data to the towers. Alternative radio communication techniques for difficult to communicate with meters include the installation of additional antennas or special data collectors that have the capability of communicating with the towers. (An existing radio communication system was selected for the advanced meter pilot program in the District of Columbia.) Cellular or landline systems typically rely on available communication networks established by cellular telephone companies and hard-wired telephone systems. The limitations of these systems include monthly access fees, rapidly changing cellular communication protocols, and cellular service coverage limitations. (PHI has piloted a hybrid Cellnet AMI System since 2005 to evaluate the capabilities of this communication system for the purposes of outage detection, AMI, and distribution automation.) Any deployment of AMI could include one or more of these communication systems.

ACE plans to deploy a two-way AMI system versus a one-way system due to the numerous operational advantages of doing so. The advantages of two-way communications include the following capabilities to support advanced applications related to: the ability to send price signals directly to customers, the ability to verify power outages and restoration, the ability to verify directly connected demand response enabling technology and remote turn on/off.

ACE will improve the Company's communications network to accommodate the increased flow of customer and distribution system data to and from ACE's operational centers. A fixed communications backbone based on optical fiber and licensed microwave communications provides a robust and secure communications platform to backhaul AMI and Distribution Automation (DA) as well as enhance the overall efficiency and reliability of its electric system. These networks will be leveraged with advanced wireless communications to provide secure communications to ACE's distribution substations, AMI data concentrators and various DA devices. Presently many of ACE's transmission substations are served by fiber and the Company has plans to install fiber and microwave to the balance of those stations as well as select distribution substations. It is important to leverage these networks across all of ACE's technology investments, as it will support all applications if they share a common communications network**.**

E. Overview of AMI Benefits

ACE has identified the following major benefits that could be derived from the universal deployment of an AMI System in its service territory. These benefits are also examined in the Company's AMI business case.

1. Remote Meter Reading

- Enables Remote Meter Reading: A permanent AMI communication network can exchange data with meters and virtually eliminate the need for any utility employee or utility contractor to access the meters on a monthly basis for meter reading. Customer benefits include increased customer security, minimized billing anomalies (misread, estimated read etc.), elimination of meter reading access issues, and the immediate availability of energy consumption data to permit rapid utility response to bill inquiries. Together these customer benefits are expected to greatly enhance ACE New Jersey customer service and to increase ACE customer service satisfaction.

- Permits more frequent readings: An AMI System creates customer benefits by enabling meter reading on a daily basis, thereby collecting hourly electricity readings. This supports the provision of additional energy consumption data to customers to improve their ability to control energy costs. An AMI System's ability to collect interval data on a daily basis creates a valuable database. This rich database, in conjunction with an internet accessible energy services portal, enables customers to readily determine how and when they use energy and to develop strategies for lowering their bills.

- Supports enhanced customer service capabilities: Resulting customer service improvements are expected to include customer selectable billing dates, improved utility response to bill inquiries, the ability to readily obtain meter readings that coincide with customer requested move dates, and the rapid utility notification of customer outages.

- Improves reading accuracy: An AMI System improves the accuracy of meter readings and, thereby, the calculation of all customer bills.

- Discovers malfunctioning meters: An AMI System includes numerous processes to verify that the meter is recording properly. Each meter includes software designed to detect meter and communication malfunctions that can be directly reported to the utility.

- Provides additional customer specific load research data: AMI Systems are designed to support customer specific load research by compiling interval data for all customers. The data can be used by ACE's distribution and transmission system planners to optimize the design of the electric system. Competitive electricity suppliers can use the data to refine their price offers to customers. Wholesale electricity suppliers participating in the Basic Generation Service auction process can improve their price bids based on the data. Additionally, the interval data support the evaluation of the impact of both energy efficiency and demand response programs.

2. Demand Response

- Integrates AMI System with demand response enabling technology: AMI Systems can support the installation of demand response technology, such as remotely controllable programmable thermostats, to directly reduce customer electricity demand during periods of high electricity demand. In the future, other electricity end-uses may be installed that have the capability to automatically reduce electricity demand during periods of high electricity prices.

- Supports demand response through pricing options that more closely track wholesale electricity market supply conditions: Examples of effective voluntary rate options that directly reflect existing electricity market conditions include: hourly pricing, critical peak pricing, and critical peak load reduction rebates. These alternative rate mechanisms can be designed to reflect either day-ahead or real-time PJM ACE Zonal Locational Marginal Prices. Participants in these rate options can reduce their monthly electricity bills by reducing their electricity consumption during high priced periods and thereby place significant downward pressure on regional electricity energy and capacity prices – benefiting all ACE New Jersey electricity customers.[14] These rate options combined with the availability of direct load control technology are a powerful tool for reducing the overall peak electricity demand in New Jersey, in a customer friendly manner.

- Enhances customer control over monthly bills through additional billing information regarding electricity consumption: As discussed above, AMI enables utilities to empower better customer control over energy costs in ways as simple as showing the customer on their monthly billing statements when they use energy.

[14] A study released on January 29, 2007 and commissioned by the Mid-Atlantic Distributed Resources Initiative ("MADRI") and the PJM Interconnection, LLC, found that electricity day ahead prices would be reduced by 5 to 8 percent or by $57 to $182 million assuming a 3 percent peak demand reduction in the Mid-Atlantic area. These saving figures will be significantly greater if price impacts on the following PJM market components are included: real time energy market prices, capacity prices, and PJM ancillary market prices.

3. Distribution System Monitoring

- Improves distribution system design, reliability and performance: Smart Grid concepts are now available that permit the utility to deploy an array of sensors and control devices supported by an AMI System to provide additional near real-time monitoring. Examples include transformer load management, feeder load analysis, recloser control, fault indicator monitoring, voltage and phase monitoring, and capacitor bank switch control.

4. Distribution System Asset Management

- Enhances Outage Reporting: Supports more rapid customer restoration time: An AMI System can detect outages without customer calls. This enables ACE to respond to outages as quickly as possible and often before the customer even knows an outage has occurred. AMI Systems are also capable of reporting momentary outages that could indicate a loose conductor coupling, loose neutral or other service issues including a rubbing tree branch.

- Dispatches Repair crews with improved accuracy: AMI data allow utilities to dispatch repair crews in a more efficient manner. The data permit the utility to acquire outage data within minutes of an event -- permitting ACE to determine the location of repair likely to restore power most quickly to the greatest number of customers. Customer benefits from this include minimization of outage inconvenience, reduction in lost revenues, and minimization of lost product (restaurants, manufacturing etc).[15]

5. Remote Service Disconnect

- Reduces utility service visits: AMI coupled with remote Service Connect and Disconnect ("SCD") enables the utility to remotely disconnect customers. This enables the utility to disconnect service for a departing customer and thereby lessening disagreements over departing/arriving customer energy use. Additionally the utility can turn on service for a new customer virtually in real time rather than the customer having to wait for a utility crew to perform the task. This increases customer satisfaction while reducing utility costs especially for locations with high levels of SCD activity. This technology is currently available for services rated up to 200 amps. AMI enables a future vision of self service for many activities allowing customers greater flexibility and increased satisfaction.

Similarly, AMI can reduce service calls and outages attributable to a customer based outage event such as a circuit breaker opening during a storm. Most customers assume the problem is utility based and the normal process is for the utility to dispatch a field crew. Conceptually, an AMI system could be used by a customer service representative for a real time meter service audit to determine if power is being supplied and if the

[15] Pennsylvania Power and Light claims that its Hurricane Isabel efforts were substantially aided by its AMI system resulting in an estimated 10% reduction in restoration costs and a 6 hour improvement in system wide recovery.

meter is operational and has not lost supply to a meter leg. In response to many of these events, ACE can assist customers to restore service in minutes without the need or expense of a field crew visit.

6. Tamper Detection

- Informs utility of possible meter tampering: AMI systems are designed to support revenue assurance and the minimization of meter tampering. This is accomplished with sensors that can detect some of the major methods of tampering to detect anomalous patterns of energy use that are otherwise difficult or expensive to detect. This helps to ensure that other customers are not unfairly burdened.

7. Supports New Rate Options

- Renewable Generators: Pricing tariffs that reward renewable generators (or other distributed generation resources) for their production of electricity during periods of high energy prices will be supported. This is particularly valuable for resources such as photovoltaic systems, which supply energy during summer weekdays. Additionally, utility monitoring of the production of all distributed generators can be accomplished remotely to ensure the adequate supply of electricity and to provide the data necessary for these resources to participate in the regional Renewable Energy Credit ("REC") market.

- Plug-In Vehicles: Rate designs that support the expected surge in the use of plug-in vehicles through pricing that is substantially lower during nights and weekends can be readily accommodated. These electricity rates will encourage greater numbers of customers to purchase these vehicles by helping to reduce their operating costs. All ACE customers will benefit through reductions in vehicle air emissions – a major source of air pollution in the State. Simultaneously dependence on foreign sources of energy will be lessened.

- Time Differentiated Pricing Options: Electricity rate pricing options that include critical peak pricing, critical peak rebate, and/or hourly prices related to day ahead or real time wholesale energy market prices can be offered by the utility and competitive suppliers. Customers electing these rates will have the opportunity to reduce their electricity bills by reducing their use of electricity during high priced hours. These rates will result in lowered demands for electricity during high priced periods, thereby lowering regional market electric energy and capacity prices and costs for ACE and all New Jersey consumers. These dynamic rates will encourage customer participation in demand response programs, including the Company's proposed smart thermostat program.

III. DEMAND-SIDE MANAGEMENT INITIATIVES

The Board's Office of Clean Energy has assumed responsibility for designing, implementing, administering, and evaluating all publicly funded electric related energy efficiency and conservation programs since July 1, 2007, with the exception of the low income (Comfort Partners) program. ACE is prepared to work closely with the Board to design and implement utility provided energy efficiency and conservation programs beginning immediately that would augment or supplant the Office of Clean Energy's programs. ACE notes that direct utility involvement in the design and implementation of these programs will be an essential component of the activities needed to help meet the aggressive energy consumption reductions desired by New Jersey policymakers and expected in the final version of the pending New Jersey Energy Master Plan. ACE's affiliated utilities, Pepco and Delmarva Power, have submitted comprehensive DSM program proposals for every customer segment. Pepco and Delmarva Power have recommended that they be responsible for designing, implementing, and managing these programs within their respective service territories.[16]

ACE is in the best position to develop, design, implement and manage energy efficiency, conservation, and demand response programs (collectively, demand-side management programs) and to provide comprehensive demand-side management programs for its electric distribution customers for numerous reasons, including the reasons described below.

A. Experience Providing Demand-Side Management Programs

ACE and its affiliated utility distribution companies have significant experience providing cost-effective demand-side management programs. ACE has more than fifteen years of experience in the provision of such programs directly to New Jersey consumers. In New Jersey, ACE achieved energy efficiency and conservation improvements in all customer segments through utility sponsored demand-side management programs impacting individual end-uses and building envelopes. ACE continues to operate a residential air conditioner/heat pump, water heater, and electric motor control program, the Peak Savers Club Program. During

[16] The Delaware Legislature has approved the establishment of an independent Sustainable Energy Utility ("SEU") within Delaware. Delmarva Power is working with representatives of the SEU to work cooperatively to implement DSM programs in Delaware.

the summer of 2007, more than 24,000 residential and small commercial New Jersey customers participated in the Peak Savers Club Program, providing more than an estimated 17 MW of peak electricity demand reduction. ACE's total lifetime energy efficiency savings achieved by historic utility energy efficiency and conservation programs from 2001 through 2006 exceeded over 300,000 MWh.

Historically, each of Pepco Holdings, Inc.'s electric distribution companies, ACE, Delmarva Power, and Pepco, have offered their customers a wide array of energy efficiency, conservation, and demand response related programs, ranging from direct control peak demand reduction programs to extensive energy efficiency loan, audit, and rebate programs. These programs were subject to the oversight of the Mid-Atlantic state and District of Columbia commissions and funded through various nonbypassable rate surcharge mechanisms. For example, Pepco's aggressive demand-side management programs achieved nearly 790 MW of peak demand reduction and over 1.9 million MWh of annual energy savings by 2001. PHI is able to apply its collective experience with DSM to implement aggressive and successful programs in New Jersey.

B. Customer Information System

ACE maintains a detailed customer information system containing specific customer address and telephone contact information, monthly electric usage data, and monthly electric billing amounts for every electricity customer it serves. This invaluable data set provides the data necessary to successfully design, implement, market, and evaluate demand-side management programs the utility provides to its New Jersey electric customers.

C. Financial Accounting System

ACE maintains a detailed financial accounting system to track all expenditures in a manner sufficient to satisfy internal budgetary requirements, meet Sarbanes Oxley and standard accounting requirements, meet regulatory Commission requirements, and fulfill Federal and State reporting requirements. The availability and careful maintenance of a detailed financial accounting system is critical to ensuring that demand-side management program funds are accounted for and spent appropriately.

D. Monthly Customer Contact

ACE communicates with each of its customers on a monthly basis through its billing system. Additionally, the Company has extensive customer contacts through its customer service and call centers. These extensive customer contacts provide the Company with significant opportunities to educate customers about demand-side management programs and to directly market demand-side management programs to customers. Existing Federal "do not call" requirements have significantly hampered the ability of entities without pre-existing customer relationships to market demand-side management programs directly to consumers.

E. Brand Awareness

ACE is a widely recognized and respected brand in New Jersey. Consumers are significantly more likely to listen and believe in messages from a known, knowledgeable, and respected entity. Other lesser known entities within New Jersey would need to spend considerable additional funds to provide energy efficiency, conservation, and demand response related information to consumers.

F. Utility Professional Staff

ACE's staff and those of its related companies have expertise and significant experience in each of the areas required to implement demand-side management programs successfully. This expertise ranges from skilled call center representatives, marketers, program managers, engineers, economists, and a skilled and committed leadership team. It is important to recognize that a skilled staff is required to implement large scale demand-side management programs requiring comprehensive planning, design, marketing, administration, and evaluation efforts.

If additional staff is needed to implement demand-side management programs, the Company has the ability to readily hire staff and/or contractors. The Company typically selects contractors through a competitive bid process, helping to ensure contractor costs are minimized, quality is maintained, and that contracting opportunities are open to all.

G. Distribution System Planning

Integrating demand-side management programs into electric distribution system planning and operation is essential to capturing all of the benefits available from demand-side management. This is particularly important for the proper implementation of demand response programs. ACE is the only entity within its service area that has this critical capability.

H. Control Center Operations

ACE operates a control center on a 24/7 basis. The Control Center interfaces directly with the PJM Interconnection, L.L.C. and monitors the flow of electricity on a real time basis in New Jersey. ACE dispatchers currently work with PJM dispatchers to operate demand response resources in the most economic and beneficial manner for the electric grid. No other entity maintains this capability for ACE's electricity customers. This capability is essential for the provision of demand response programs in New Jersey, such as the Company's proposed remotely controllable smart thermostat system program.

I. Announced Demand-Side Management Program Plans In Other Jurisdictions

ACE's affiliate utility, Delmarva Power has announced plans to provide similar demand-side management programs to its customers in Maryland and Delaware. PHI's affiliate utility, Pepco has announced plans to provide similar programs to its customers in the District of Columbia and Maryland. Operating and offering similar demand-side management programs across multiple jurisdictions offers significant economies of scale for the Company and advantages to our more than 500,000 New Jersey customers. For example, a demand-side management customer awareness campaign conducted in Maryland will have positive spill over affects in Delaware and the costs of administering one program across multiple jurisdictions will be significantly less per participant than doing so for one jurisdiction alone. The Maryland Commission has recently approved PHI's first Delmarva Power and Pepco Blueprint proposed DSM programs – a three year residential efficient lighting campaign and accompanying customer awareness campaigns. (Commission Order No. 81618, Formal Case No. 9111, issued on September 20, 2007)

The types of DSM programs recently recommended by ACE's affiliated electric distribution utilities, Pepco and Delmarva Power, for utility implementation include the following:

1. General Energy Awareness Campaign

- Customer DSM Education/Marketing Effort

2. Residential Programs

- Home Performance w/ENERGY STAR® Program – Home Audit Based Program;
- High Efficiency Central Air Conditioner/Heat Pump Rebate/Installer Training Program – Promotes Proper Sizing/Installation of High Efficiency Units;
- High Efficiency Window Air Conditioner Rebate Program – Promotes Selection of High Efficiency Modes at Point of Purchase;
- Residential High Efficiency Lighting Program[17] – Promotes use of Compact Fluorescent Lighting through Participating Retailers through a Mid-Market Campaign;
- Residential New Construction Program – Promotes Installation of Energy Efficient Equipment and Measures at Time of Construction;
- Smart Thermostat Program – Remotely Controllable Thermostats to Reduce Peak Electricity Demand and Provide Cooling and Heating Related Energy Savings (linked with AMI deployments).

[17] ACE, Delmarva Power, and Pepco are active participants in the national ENERGY STAR® "Change a Light Change the World" campaign.

3. Non-Residential Programs

- Building Commissioning and O&M Program – Consulting/ Engineering Services to Improve Energy Efficiency of Existing Buildings and to Identify Peak Demand Savings Opportunities**;**
- New Construction Program – Consulting/Engineering Services to Improve the Design of Energy Efficient Buildings Prior to and During their Construction;
- HVAC Efficiency Program – Promotes Installation of High Efficiency HVAC Equipment up to 30 Tons through Rebates, Education, and Contractor Training;
- Prescriptive Program – Energy Efficiency Measure Incentives for Electric Motors and Lighting;
- Custom Incentive Program – Provides Rebates for Installation of Site Specific Energy Efficiency Measures;
- Smart Thermostat Program – Remotely Controllable Thermostats to Reduce Peak Electricity Demand and Provide Cooling and Heating Related Energy Savings (linked with AMI deployments);
- Internet Platform – Internet Based Platform to Facilitate Participation in PJM Demand Response Market.

Detailed program descriptions are contained within the Delmarva Power Maryland and Delaware Blueprint filings and within the Pepco Maryland and District of Columbia Blueprint related filings.[18] ACE proposes to build upon the successful elements of the existing DSM programs within its service territory to ensure that additional energy savings opportunities are captured. PHI anticipates that its DSM implementation experiences across its distribution company footprint will significantly improve program design and implementation in all of its service territories.

J. Regulatory Oversight by the Commission

Board oversight of ACE operations, together with the participation of the Division of Rate Counsel, ensures that utility demand-side management related expenditures are prudently made and that consumers benefit from funded programs. Similar comprehensive regulatory oversight is not provided over demand-side management expenditures made by other entities and therefore, there is little assurance that ACE customer are receiving the benefits they are paying for.

K. Commitment of Senior Leadership

ACE's senior leadership team is strongly committed to the provision of demand-side management programs and is prepared to dedicate the necessary resources to make the programs a success. The Company's leadership believes that providing demand-side programs to its customers will help them reduce their monthly energy costs, place downward pressure on energy commodity prices, mitigate generator market power, lessen power plant air emissions, and help lessen future constraints on the regional transmission system. Succinctly stated, the Company's leadership team believes that providing demand-side management programs to our customers is

[18] See Delaware Delmarva Power Blueprint Filing of February 6, 2007; Maryland Delmarva Power Blueprint Filing of March 21, 2007; Maryland Pepco Blueprint Filing of March 21, 2007; District of Columbia Pepco Blueprint Filing of April 4, 2007, DC Formal Case No. 1056; Maryland Delmarva Power Energy Conservation and Demand Response Plan Filing of October, 26, 2007, MD Formal Case No. 9111; and Maryland Pepco Energy Conservation and Demand Response Plan Filing of October 26, 2007, MD Formal Case No. 9111.

the "right thing to do" and that the Company must act to put programs in place to better serve our customers in New Jersey. PHI's recent commitment to the Clinton Global Initiative to boldly support energy efficiency initiatives to reduce power plant air emissions underscores this position.

L. Implementation Plans

ACE's implemented DSM programs in New Jersey will build upon the existing DSM programs currently operated by the Board's Office of Clean Energy. The Company is prepared to assume management responsibility for existing DSM programs in the near-term and to work with the Office of Clean Energy to establish an appropriate transition process and time period. ACE will work collaboratively with the Board and New Jersey electricity market stakeholders to refine, improve, and augment existing DSM programs. An important near-term step for ACE will be an evaluation of the successes of existing and recent DSM programs in southern New Jersey. ACE proposes to submit planned utility DSM program additions and improvements to the Board for its approval prior to implementing any new or revised programs. The Company is committed to implementing aggressive DSM programs within its service territory that fully use collected SBC funds to assist the State in achieving its aggressive energy savings goals. ACE will submit quarterly DSM program reports to the Board for its review.

IV. DEMAND RESPONSE PROGRAM PROPOSALS

ACE's planned installation of an AMI System supports the introduction of three new proposed ACE demand response programs: 1) a residential/small commercial remotely controllable smart thermostat program to permit the utility to reduce summer air conditioner load during peak periods, 2) a dynamic pricing program to offer all Basic Generation Service customers[19] a default or optional critical peak pricing or critical peak rebate rates, and 3) an Internet based demand response platform to support larger-size customer participation in the PJM demand response program.

A. Direct Load Control Program

As noted earlier, ACE continues to operate its Peak Savers Club Program to reduce summer peak electricity load through the direct control of residential air conditioners, water heaters, and electric motors. This Program relies upon the use of aging one-way direct load control switches. The only method to validate the operability of this equipment is to inspect the switches through costly field inspections by qualified technicians.

On May 23, 2006, the Board issued an Order approving a settlement agreement regarding the future operation of existing New Jersey direct load control programs. In the May 2006 Order, the Board directed New Jersey utilities to work with the Board Staff and the Division of Rate Counsel to evaluate existing utility direct load control programs and to recommend the "future direction" of the programs. In consultation with the Board Staff and the Division of Rate Counsel, the utilities hired Summit Blue Consulting, LLC to work with the parties to develop recommendations regarding these direct load control programs. On June 7, 2007, in conformance with the May 2006 Order, ACE, Jersey Central Power and Light Company, and Public Service Electric & Gas Company, jointly filed a proposal, "New Jersey Direct Load Control Program Proposal" to expand their existing direct load control programs in the manner recommended by Summit Blue. That filing stated that each utility would subsequently submit its

[19] The availability of dynamic pricing for customers receiving electricity through the BGS process is expected to also support and encourage the provision of dynamic electricity supply pricing by competitive retail electricity suppliers.

Company specific plan to the Board for consideration. On August 20, 2007, ACE filed its Company specific plan, Docket No. EO06040297. ACE's filing provided proposed program details for 2008 and stated that proposed program details for the period of 2009 through 2012 would be presented in this filing. (ACE, August 20, 2007 Filing, p. 3). As of this filing, the Board has not acted on ACE's August 20th filing.

ACE hereby sets forth the specifics of its remotely controllable smart thermostat program for the period of 2008 through 2012. The Company's proposed smart thermostat program has been designed to be linked to the deployment of the AMI System as that System is deployed by ACE. In this manner, ACE will establish two-way communication with each smart thermostat. The AMI enabled communications system will enable ACE to integrate its smart thermostat program with a dynamic pricing program, provide messaging information through the thermostat display (daily consumption data, energy price data, etc.), and verify that the thermostat is operational.

In accordance with the joint New Jersey utility filing on June 7, 2007, the Company proposes to install new direct load control ("DLC") equipment for residential central air conditioning and electric heat pump systems in the ACE service territory beginning in 2008. By 2012, it is expected that 42,200 ACE customers will voluntarily[20] participate in the new program and provide peak electricity demand reduction capability of approximately 50 MW. The overall cost of this program during the 2008 through 2012 period is estimated to be $16.6 million.

[20] ACE notes that an alternative approach that would significantly increase customer participation and reduce marketing expense would be for the Board to mandate residential and small commercial customer participation in the program. ACE is willing to work with New Jersey stakeholders to examine the benefits and appropriateness of such an aggressive approach. ACE's expected market penetration rate is based upon the market projections made by Summit Blue.

ACE's new residential DLC program has been designed based upon the program recommendations contained in the recent Summit Blue Consulting Report, "New Jersey Central Air Conditioner Cycling Program Assessment," issued on June 4, 2007 and submitted to the Board as part of the June 7, 2007 joint utility filing.[21] This filing sets forth the expected program participation levels during the period of 2008 - 2012, the expected peak electricity demand impacts, proposed program budgets, and the proposed cost recovery method. The Company seeks Commission approval of ACE's new residential direct load control program and proposed cost recovery method in the near-term to permit time for vendor selection, marketing, and installation of equipment prior to the 2008 summer.

1. Program Summary

ACE proposes to install remotely controllable smart thermostats at residential customers' homes and later expand the program to small commercial customers to enable the Company to reduce peak electricity demand during periods of high summer electricity use. The program will be created in a manner that comports to the requirements of the PJM demand response wholesale market. Residential customer participation will be voluntary and incented by the one time payment of $50 and the receipt of a smart thermostat, in accordance with the recommendations of Summit Blue. (Report, p. 80). The deployed remotely controllable smart thermostats are expected to have the following minimal capabilities: 1) operate as programmable thermostats for customers, 2) be uniquely addressable by ACE, 3) have the capability of communicating in the near-term through cellular or radio communications and in the near future through the deployed AMI System, and 4) be capable of reducing central air conditioner system load through both

[21] Board Staff, the Division of Rate Counsel, and the New Jersey electric distribution utilities participated in the preparation of the Summit Blue Report. This Report contains the cost-effectiveness justification for the implementation of new utility sponsored direct air conditioning load programs. (Report, p. 60 -72).

temperature setback and cycling options. Consideration will be given to selecting equipment that can be retrofitted to communicate with future deployment of advanced metering equipment. Recruitment of residential customers and installation of equipment is expected to begin during 2008 and conclude during 2012, when 17 percent of eligible residential customers are expected to participate in the program.[22]

Smart thermostats offer significant advantages over the equipment used in ACE's existing direct load control program, the "Peak Savers Club Program." These very significant advantages include the following:

- Unique addressability by the utility for each customer participant – enabling utility individual feeder load control and utility ability to remotely modify individual customer program enrollment.
- Indoor smart thermostat location compared with outdoor direct load control switch location – significantly reducing the likelihood of the removal of direct load control equipment by HVAC contractors or customers.
- Alternative cycling control strategies that can be selected by the utility, subject to participant agreement.
- The potential ability over time to provide utility messages to customers that include such information as the current price of electricity, current cycling activities, and bill-to-date information after supporting advanced metering equipment has been installed.

[22] Expected New Jersey new DLC program participation rates were developed by Summit Blue. Mandatory participation of eligible customers would achieve a significant penetration rate.

- Programmable thermostat capability to permit customers to automatically revise cooling and heating system settings. Customers who take advantage of this capability can significantly reduce their energy use for cooling and heating. (Deployed smart thermostats will be initially programmed at the time of installation in conformance with each participant's preference.)
- The potential future ability to communicate directly with a deployed smart meter that enables a customer to automatically respond to high electricity prices during periods of high summer electricity demand.
- The future possibility of being used by New Jersey gas distribution companies to reduce residential gas heating use during periods of high winter gas demand, subject to participant heating equipment and their agreement.

Near-term communication with each smart thermostat is anticipated to be one-way via radio. Beginning in 2011, when ACE deploys its planned AMI System,[23] thermostat communication will be upgraded to two-way through the AMI System for newly installed smart thermostats and potentially for smart thermostats that have already been installed. Two-way communication capability through the AMI System offers significant benefits that include numerous customer service benefits and a variety of utility operational improvements, including the ability to verify the operational capability of direct load control equipment remotely, thereby avoiding costly site inspections. AMI supported dynamic pricing options could permit the smart

[23] ACE plans to submit a filing to the Board later this year describing its planned deployment of an Advanced Metering Infrastructure for all of its electric distribution customers.

thermostat to receive energy pricing information directly through the meter and greatly increase the quantity of customer demand response available within the ACE service territory.

2. Deployment/Participation Plan

The targeted residential customer deployment participation rate is contained in Table 1. As noted previously, recruitment of residential customers and installation of equipment is expected to begin during 2008 and conclude during 2012 when 42,200 participants (17 percent of eligible residential customers) are participating in the program. This approach is consistent with Summit Blue's recommendations. During 2008, ACE proposes to recruit 5,000 residential customer program participants that are electrically connected to a limited number of specific distribution system feeders with high summer peak electric loads. In 2009 and 2010, customers located on additional feeders will be invited to participate. Beginning in 2011, additional customer participation eligibility will be related to ACE's planned deployment plan. Eligible residential customers must have an electric central air conditioner or heat pump. Existing residential Peak Savers Club participants located on the eligible feeders will have the option of upgrading their current DLC equipment to smart thermostats, subject to all of the terms of the new program.

The Company plans to select equipment and installation vendors through a competitive vendor RFP process after receipt of Board approval to implement the program, to recruit customer participants during the first and second quarters of 2008, and to install equipment during the second and third quarters of 2008. Load research metering equipment will be installed on a statistical sampling of homes and feeders to permit the Company to verify the magnitude of resulting summer load reductions.

Table 1
ACE Residential DLC Program Deployment Schedule

Year	2008	2009	2010	2011	2012
Incremental Participants	5,000	9,300	9,300	9,300	9,300
Total Participants	5,000	14,300	23,600	32,900	42,200

The future deployment of an AMI System will provide advanced metering for all of its distribution customers. As noted previously and described in the Summit Blue Report, the availability of AMI is expected to support two-way communications to future DLC equipment, to provide detailed interval data supporting load reduction estimates, and to offer supporting electricity dynamic pricing options[24] that reflect wholesale PJM electricity market prices on either a day ahead or real time basis. ACE concurs with the Summit Blue conclusion that the coupling of direct load control equipment with AMI will be the most cost-effective approach to direct load control programs over future years.

ACE will recommend future program revisions to the Board based upon achieved customer participation levels, achieved load reductions, equipment operational capability, and the timing of planned AMI System deployment. Therefore, ACE anticipates that it will be necessary to modify the deployment schedule for the 2009 through 2012 time period displayed in Table 1 after the 2008 summer.

3. Peak Electricity Demand Impact

Summit Blue has estimated that peak electricity demand reductions will average 1.2 kW per residential program participant. Table 2 contains the peak electricity demand reduction

[24] Future pricing options might include hourly prices, critical peak prices, or critical peak rebates. Dynamic pricing options could be mandated or made optional by the Board, depending upon policy objectives.

estimates that will be achieved by ACE, if the deployment schedule contained in Table 1 is achieved. By 2012, resulting peak demand reductions are expected to exceed 50 MW. Additional demand reductions will be achieved when an AMI System is deployed and dynamic pricing options are available to residential customers.

Table 2
ACE Residential DLC Program Peak Demand Impact
(MW)

Year	2008	2009	2010	2011	2012
Incremental	6	11.2	11.2	11.2	11.2
Cumulative	6	17.2	28.3	39.5	50.6

4. Program Budget

ACE has developed a program budget based upon the deployment schedule contained in Table 1. Actual expenditures will vary based upon vendor selection and negotiations and customer participation rates. A brief description of each program element is provided below:

- Smart Programmable Thermostats – Summit Blue estimates the cost per thermostat to equal $200 for capital and $100 for installation.[25]
- Load Research Meters – 100 whole house load research meters, providing adequate sampling for a residential control group and adequate sampling of participants. (When the AMI System is deployed, future load research metering

[25] No additional communication costs are included at this time. The Company plans to rely upon existing radio communication capability. If this equipment is determined to be inadequate to provide the necessary communications to the new DLC equipment, ACE will incur additional expense for any required upgrade. The deployed thermostats will be designed to be compatible or upgradeable to communicate through the AMI System when it is deployed.

related expense will be avoided by the availability of hourly interval load data for all customers.)

- Load Research Feeders – ACE has included funds to support the monitoring of three feeders so that the feeder level impact of deployed smart stats can be monitored. The Company plans to install three phase metering on each of the monitored feeders and to expand this monitoring capability as the program is expanded.
- Marketing expenses will be incurred for direct mail recruitment materials, mailing expense, and the handling of customer inquiries. Actual customer response rates will determine direct mail related expenses.
- Incentive amounts are assumed to be $50 per participant, as recommended by Summit Blue.[26] Additional incentive amounts may be required if targeted market penetration is not achieved.
- PJM demand response market earnings may be available for sharing with program participants or to offset utility program costs through participation in the PJM demand response market. Under current BGS market rules, these benefits are passed directly to generation suppliers. The current presumption is that BGS suppliers will reduce their supply bid prices to reflect the financial value they derive from existing direct load control programs. However, ACE recommends that BGS supplier rules for new utility sponsored direct load control programs be modified to permit ACE to capture all direct PJM market incentives to offset and

[26] The Company assumes that a minimum customer "stay" provision will be required.

lessen ACE DLC program costs for customers and/or provide additional incentives to program participants. ACE recommends that the existing BGS rules be modified to permit the utility to capture these financial benefits for the benefit of customers.

- Annual program maintenance expense is estimated based upon existing annual ACE Peak Savers Club Program maintenance expense.
- Load research monitoring expense represents the additional expense to retrieve and store program related load research data.

Program budgets for the period of 2009 through 2012 will be revised after program vendors are competitively selected and vendor contract negotiations completed.

Table 3
ACE Residential DLC Program Budget
(2007 Dollars)

Category	**2008**	**2009**	**2010**	**2011**	**2012**	**Total**
Capital						
T-Stats/Installation	1,500,000	2,790,000	2,790,000	2,790,000	2,790,000	12,660,000
LR Meters	30,000	0	0	0	0	30,000
LR Feeders	195,000	195,000	195,000	195,000	195,000	975,000
Subtotal	*1,725,000*	*2,985,000*	*2,985,000*	*2,985,000*	*2,985,000*	*13,665,000*
O&M						
Marketing	46,000	32,500	32,500	32,500	32,500	147,500
Incentive	250,000	465,000	465,000	465,000	465,000	2,110,000
Maintenance	17,500	90,000	90,000	90,000	90,000	450,000
LR Monitoring	90,000	46,000	46,000	46,000	46,000	230,000
Subtotal	*403,500*	*633,500*	*633,500*	*633,500*	*633,500*	*2,937,500*
Total	**2,128,500**	**3,618,500**	**3,618,500**	**3,618,500**	**3,618,500**	**16,602,500**

5. Tariff Rider

ACE recommends and respectfully requests that specific program operational rules and participation requirements be included as a rider to the Company's residential rate tariffs. As noted earlier, the new program will be designed to operate in a manner that permits the Company to operate the program in conformance with the existing PJM demand response market. The Company's proposed rate rider will be submitted to the Board for its approval as part of a compliance filing after receipt of Board approval to implement the proposed DLC program.

6. Small Commercial Customers

Beginning in 2011, at the expected time of AMI deployment, ACE proposes to expand the smart thermostat program to eligible small commercial customers at the time they receive an AMI meter. Summit Blue has examined the available small commercial load impact studies and determined that load reductions achieved by this program are "generally twice as high as residential impacts." (Summit Blue Report, p. 32) Summit Blue did not calculate cost-benefit ratios for small commercial customers, but stated that the small commercial cost-benefit ratios will be higher. (Summit Blue Report, p. 63) If the Board approves ACE's implementation of a residential remotely controllable smart thermostat program, the Company will work with the Board, the Rate Counsel, and market stakeholders to develop a detailed plan to expand the program to small commercial customers. This plan would be submitted to the Board for its approval during 2010. Preliminary Company estimates, suggest that if a small commercial smart thermostat were implemented on an optional basis for customers, 40 MW of additional peak demand could be achieved by year-end 2012.

Table 4 contains the anticipated market penetration rate of the small commercial program and Table 5 contains the projected peak demand impacts. Market penetration estimates are based upon an assumed customer participation rate of 17 percent, similar to that estimated by Summit Blue for the residential customers. Peak demand impacts are based upon an estimated 4.4 kW peak demand reduction per installed smart thermostat.[27]

Table 4
ACE Commercial DLC Program Deployment Schedule

Year	2008	2009	2010	2011	2012
Incremental Participants	0	0	0	4600	4600
Total Participants	0	0	0	4600	9200

Table 5
ACE Commercial DLC Program Peak Demand Impact
(MW)

Year	2008	2009	2010	2011	2012
Incremental	0	0	0	20.2	20.2
Cumulative	0	0	0	20.2	40.4

A preliminary budget for the small commercial smart thermostat program is contained in Table 6 and projects a total deployed expense of $3.8 million. [28]

[27] *See* Summit Blue report, p. 43.

[28] Additional load research metering related costs are not anticipated because of the expected availability of hourly energy use data through the deployed AMI System.

Table 6
Preliminary ACE Commercial DLC Program Budget
(2007 Dollars)

Category	2008	2009	2010	2011	2012	Total
Capital						
T-Stats/Installation	0	0	0	1,380,000	1,380,000	2,760,000
Subtotal	*0*	*0*	*0*	*1,380,000*	*1,380,000*	*2,760,000*
O&M						
Marketing				10,000	10,000	20,000
Incentive	0	0	0	460,000	460,000	920,000
Maintenance	0	0	0	45,000	45,000	90,000
Subtotal	*0*	*0*	*0*	*515,000*	*515,000*	*1,030,000*
Total	**0**	**0**	**0**	**1,895,000**	**1,895,000**	**3,790,000**

- Smart Programmable Thermostats – Summit Blue estimates the cost per residential thermostat to equal $200 for capital and $100 for installation.[29] ACE has assumed that these costs will be similar for small commercial customers.
- Marketing expenses will be incurred for direct mail recruitment materials, mailing expense, and the handling of customer inquiries. Actual customer response rates will determine direct mail related expenses. Overall marketing expense is projected to equal that of the larger residential program due to the greater diversity of the small commercial customer market segment.

[29] No additional communication costs are included at this time. The Company plans to rely upon existing radio communication capability. If this equipment is determined to be inadequate to provide the necessary communications to the new DLC equipment, ACE will incur additional expense for any required upgrade. The deployed thermostats will be designed to be compatible or upgradeable to communicate through the AMI System when it is deployed.

- Incentive amounts are assumed to be twice as high as they are for the residential program. Additional incentive amounts may be required if targeted market penetration is not achieved.
- PJM demand response market earnings may be available for sharing with program participants or to offset utility program costs through participation in the PJM demand response market
- Annual program maintenance expense is estimated based upon existing annual ACE Peak Savers Club Program maintenance expense.

B. PJM Market Earnings

As previously noted, BGS suppliers currently receive available market benefits from existing New Jersey direct load programs. The current presumption is that BGS suppliers will reduce their supply bid prices to reflect the financial value they derive from existing direct load control programs. However, ACE recommends that BGS supplier rules for new utility sponsored direct load control programs be modified to permit ACE to capture all direct PJM market incentives and that the Company be permitted to use those funds to offset and lessen ACE DLC program costs for customers. [30]

C. Dynamic Pricing Rate Structures

The deployment of an AMI System will enable ACE to expand dynamic pricing for electricity to all of its distribution customers. Under dynamic pricing, actual electricity prices are designed to reflect wholesale market energy prices at differing times of day. For example, ACE’s affiliated electric distribution company, Pepco is testing three alternative forms of

[30] Any modification to BGS rules must be established well prior to any bid period to ensure suppliers are able to factor the requirements into their bid prices.

dynamic pricing for residential customers at this time based upon day ahead sub-zonal hourly Locational Marginal Prices ("LMP") PJM energy prices for the District of Columbia. These alternatives forms are: 1) hourly prices, 2) critical peak period prices, and 3) critical peak rebate prices. In the District of Columbia, participants in the test will receive price signals on the day before the prices are effective. District of Columbia low income customers are restricted to participation in the critical peak rebate program only to ensure that their energy costs will only be equal to or lower than their current level.

PHI retained the Brattle Group to estimate the likely peak load reductions achievable from a critical peak pricing structure in the ACE service territory in New Jersey. Brattle estimates that 41 MW of ACE peak demand will be reduced if critical peak pricing is optional and 20 percent of eligible customers who participate are priced under the rate. If the critical peak pricing is mandated by the Board with an option for reverting to a non-dynamic price, 148 MW of ACE peak demand will be reduced, assuming 80 percent of eligible participants participate. These estimates were developed only for ACE customers who do not currently have interval metering.[31] If dynamic prices were adopted throughout the year, additional incentives would be available to reduce or shift energy use during weekday afternoons, when energy prices are higher.

Dynamic pricing will help to encourage customers to install photovoltaic systems by enabling the payment of a higher market based price for the output of each unit based upon the higher prices of energy during the day and particularly during the many hours of daylight on summer weekdays. Dynamic pricing will help encourage the adoption of plug-in vehicles and

[31] The existing ACE interval metering threshold is one Megawatt. Additional peak demand reductions are achievable if all of ACE's New Jersey distribution customers adopt a dynamic price structure.

ensure that the majority of these vehicles are recharged during the night during periods of lower energy costs.

ACE recommends that the Board convene a working group to discuss alternative forms of dynamic pricing rate structures in the near-term that would be submitted for Board approval and implemented at the time of AMI deployment.

D. Internet Load Reduction Platform for Load Curtailments

ACE proposes to establish an Internet Platform for load curtailments to motivate non-residential customers to participate in PJM load response programs by providing a convenient method to do so. The number of eligible customers will increase significantly as AMI is deployed, providing the PJM required hourly energy data. Participants will receive energy use information, ACE Zonal PJM Locational Marginal Prices for energy, and load reduction calculations will be provided through the Internet Platform. The minimum size for customer participation will be set at 100 kW to correspond with existing PJM market rules. Customer incentives will be based upon the load reductions that are achieved. ACE proposes to share 70% of the earnings with participants and retain a 30% to offset program costs. Payment to customers participating through ACE will appear as credits on the customer's electric distribution bill. Participants will have the option at any time to exit this Program and participate in any PJM demand response program through a competitive Curtailment Service Provider, a Load Serving Entity, or directly with PJM. ACE expects to enroll 10 MW of peak demand reductions in this program after three years. Three year program costs are presented below.

Table 7
ACE Demand Response Internet Platform Budget
(2007 Dollars)

Year	Utility Administration	Marketing	Outside Services	Capital Equipment	Evaluation	Total Non-incentive Costs	Incentives	Total Program Cost
Year 1	$30,000	$40,000	$25,000	$170,000	$0	$265,000	Mkt.	$265,000
Year 2	$20,000	$20,000	$25,000	$0	$0	$65,000	Mkt.	$65,000
Year 3	$20,000	$20,000	$25,000	$0	$12,000	$77,000	Mkt.	$77,000
Total	**$70,000**	**$80,000**	**$75,000**	**$170,000**	**$12,000**	**$407,000**	**Mkt.**	**$407,000**

E. Comprehensive Energy Saving Pilot ("CESP") Program

In an effort to assist New Jersey policymakers achieve Governor Corzine's ambitious electricity reduction goals, it will be necessary to create a holistic approach to reducing electric-grid sourced electricity consumption. Therefore, ACE proposes to establish a comprehensive energy savings pilot program that will seek to maximize individual customer electric grid-sourced electricity consumption through an integrated approach consisting of the installation of energy efficiency and conservation measures, installation of renewable on-site generation, installation of demand response enabling equipment, and over time, integration of installed measures with a dynamic electricity pricing structure supported by AMI deployment. The Company proposes to implement a three to five year pilot program that will demonstrate and examine the extent to which individual residential customers and select public schools can lessen their electric footprint. ACE will develop a pilot team to select and design measures that are appropriate for each participant and to work with participants to install selected measures. ACE proposes to initiate the first stage of the pilot program in 2008. Detailed pilot program design will be provided to the Board prior to project start.

1. Residential Component

ACE proposes to work with a new home builder designing a new subdivision in southern New Jersey to integrate as many energy efficiency, conservation, renewable generation, and demand response measures as are reasonably practicable. It is anticipated that approximately 25 new homes would participate in the program.

2. School Component

ACE proposes to work with three existing public schools to integrate these technologies into their daily operations.

3. Pilot Demonstration

ACE will work with participants to showcase each project, demonstrating achievable energy savings to developers, building operators, electricity consumers, and New Jersey policymakers.

4. Pilot Evaluation

ACE will monitor the energy consumption of each participant and conduct a detailed program evaluation at the conclusion of the five year pilot program. The Company will prepare a final evaluation report/case study detailing the findings of the pilot program. ACE will seek to partner with a local university to provide technical support for the project and educational benefits to the students.

5. Program Costs

ACE will seek to fund the installation of select measures through available DSM and renewable incentives and to work with participants to provide additional incentives, as needed.

Additional incentives could include low interest loan financing options. Participants are expected to cover a portion of installed costs for each installed measure. ACE recommends that all utility incurred pilot expense be recovered through the existing New Jersey Societal Benefit Charge ("SBC"). Preliminary utility incurred projected pilot costs are estimated to be $5 million at this time.

V. LOW INCOME PROGRAMS

ACE recognizes the continuing concern of affordable energy for low income customers. The Company continues to actively work with low income customers, county agencies, community groups, and other key stakeholders to help meet the needs of these customers. ACE holds an annual low income summit to facilitate an exchange of ideas to better serve low income electricity consumers. The Company's Vice President responsible for Business Transformation presented an overview of ACE's overall Blueprint for the Future Plan during the October 10, 2007 ACE and Delmarva Power Annual Low Income Energy Assistance Summit.

Currently, ACE and six other electric and gas utilities jointly manage New Jersey's statewide Residential Low Income Program, known as "Comfort Partners." Since the program's inception in 2001 under the New Jersey Clean Energy Program, ACE has contributed to the success of this low income program that is designed to improve energy affordability for low income households through the installation of comprehensive energy measures. The seven utilities have operated through a dynamic Working Group structure to jointly administer the Comfort Partners program. The Working Group also includes Board representation. ACE has developed a wealth of experience in designing, implementing and assisting in the evaluation of this low income program; and has contributed to all decisions made regarding its operation.

Selection of program delivery contractors and program delivery costs are shared between the participating gas and electric utilities.

To ensure that low income customers' electricity costs are not adversely affected or are reduced through AMI deployment, ACE recommends the following. First, any identified low income customer would be placed on critical peak rebate rates after AMI deployment. Under these rates, low income customers would receive a rebate for reducing their energy consumption during peak electricity demand periods and would not face any risk of a higher price from their inability to do so. Second, any additional AMI capital costs could be recovered from non-low income customers through distribution rates.[32] Third, ACE proposes to offer identified low income customers a choice of either a remotely controllable smart thermostat or an energy consumption display device[33] – both of which will communicate through the deployed meter.[34] Both devices are expected to provide customers with the ability to closely monitor daily energy consumption and energy prices so that customers can better control their monthly electricity bills rather than receive the information through the ACE bill.

In the District of Columbia, ACE's affiliated company, Pepco, is currently testing the provision of both energy consumption and estimated bill to date information via smart thermostats. ACE estimates that installed display devices will cost approximately $200 each and that 2,000 low income customers will select this option for a total deployed cost of $400,000.

[32] The state government or local governments would be responsible for identifying and coding low income residential customers.

[33] The Company will evaluate the benefits of making this device available to other customers, but anticipates if it does so, that customers would pay for the cost of any deployment.

[34] The timing of the availability of these devices for individual customers will be dependent upon the timing of smart thermostat availability or AMI meter installations.

Cost estimates for deployed smart thermostats are contained within the program budget projection. It is difficult to project the peak demand and energy savings that will result from the display devices, so these figures have not been included in the projected demand and energy savings.

VI. SOLAR PROGRAMS

ACE proposes to establish two new programs that will result in the installation of 3.5 MW of additional photovoltaic distributed generation capacity over a 5 year period in New Jersey. These installations will assist the State to achieve its aggressive solar renewable portfolio standards goal. Importantly, the installations are expected to provide additional generation capability during periods of high summer peak electricity demand while simultaneously reducing power plant air emissions. The Company respectfully requests that the Board approve the following two utility programs at this time.

A. **ACE Facility Installations**

Under this initiative, ACE would purchase and own photovoltaic equipment that would be installed at utility owned substations and used to serve substation load in addition to providing excess power to the electricity distribution network. Photovoltaic equipment would also be installed on company owned and leased buildings and used to serve facility load in addition to providing excess power to the electric distribution network. Photovoltaic equipment would be purchased from and installed by competitively selected vendors. Equipment costs would be recovered through base electric distribution rates. Earnings from energy sales and the New Jersey market sale of solar renewable energy credits would be used to offset distribution utility revenue requirements. ACE's preliminary engineering analysis suggests that 50 ACE facilities are potential photovoltaic sites and could provide a total of 500 kW of additional solar capacity. The Company estimates that photovoltaic equipment could be installed at selected company sites within 24 months of Board approval.

B. **ACE Customer Installation Program**

Under this program, ACE would arrange for the installation of a net metered/interconnected photovoltaic array on any qualified ACE customer's property. In addition to the turn-key installation of systems, the Company would provide a 15 year maintenance program to ensure that the installed units continue to generate electricity during that time period. Program costs would be recovered over a 15 year period through a line item charge on participating customer's ACE distribution bills. Interest charges would be discounted and set at a fixed interest rate of two percent below market, the discount of which could be lower or higher depending on subsidies available through New Jersey's Societal Benefits Charge. Customers would own the installed photovoltaic equipment, receive available Federal and State tax credits, receive any available State provided rebates, reduce their monthly energy supply costs, receive net energy metering related payments, and receive funds through the sale of generated renewable energy credits. Competitive photovoltaic equipment vendors and installers would be certified by ACE to provide these services directly to customers. Long-term maintenance of the installed equipment would be provided through competitively selected vendors. If approved by the Board, ACE proposes to establish a distribution rate tariff for this service.

ACE's customer photovoltaic installation program addresses several existing solar market problems: 1) it provides ready customer financing; 2) it provides turn-key installation services; 3) it ensures that systems are properly installed; and 4) it ensures that installed systems are properly maintained. The Company estimates that 1,000 photovoltaic systems would be installed under this program, increasing state photovoltaic generating capacity by 3.5 MW within a five year period. Actual achieved customer installations are expected to vary based upon the changing cost of systems, the availability and magnitude of State and Federal incentives, and actual loan interest rates.

Utility incurred program costs will include utility administration expense, marketing costs, evaluation costs, and the cost of buying down interest on the offered loans. Total program costs over a five year period are expected to be approximately $2 million, with the majority of the incurred cost representing the interest buy-down expense.

To assist customers with the installation of solar systems, the Company has developed a Green Power Connection portal located on its Internet Website. This site provides customers with detailed information regarding the installation of renewable energy-generating systems, such as solar panels and wind mills, on their property and to ensure they are safe and compatible with our electrical systems. The Website provides information to assist the customer to determine available State and Federal incentives. If the Commission approves the ACE customer installation program, this website will serve as another method of providing important program information to customers.

VII. COST RECOVERY

ACE's Blueprint for the Future is an aggressive plan designed to provide real and substantial benefits to the Company’s New Jersey customers. To successfully implement the plan and achieve its many benefits ACE will be required to make significant capital and financial commitments. Such commitments require companies, regulators and others to implement innovative, yet appropriate, regulatory and cost recovery approaches. Some of those innovations have been endorsed and encouraged by independent groups such as the National Action Plan for Energy Efficiency Coalition. Some have been adopted in other jurisdictions served by ACE's affiliated utilities, Pepco and Delmarva Power. ACE urges the Board to give serious and open-minded consideration to the following proposals designed to facilitate the many benefits to ACE's customers made possible by the Blueprint.

A. Distribution Rate Decoupling

ACE recommends that the Board establish a working group to examine alternative distribution utility rate methods in an effort to remove distribution utility financial disincentives related to the promotion of DSM and renewable programs, thereby better aligning the financial interests of the Company and its shareholders with the interests of New Jersey consumers and state policy makers. PHI’s Maryland distribution utilities, Pepco and Delmarva Power, recently received the approval of the Maryland Public Service Commission for its Bill Stabilization Adjustment (“BSA”), which decouples distribution rates from energy throughput. (Maryland Commission Order No. 81517, Formal Case No. 9092, issued on July 19, 2007 and Maryland Commission Order No. 81518, Formal Case No. 9093, issued on July 19, 2007.) Pepco has proposed a similar BSA mechanism in its District of Columbia electric base distribution rate case. (District of Columbia Formal Case No. 1053). Delmarva Power has recommended a similar BSA mechanism in Delaware. (Delaware PSC Docket No. 05-304). Under the BSA proposals in other jurisdictions, individual customer distribution charges are related to consumption, but overall distribution charges are adjusted so that utility earnings remain constant regardless of total throughput. Distribution rate decoupling is supported by the Clinton Global

Initiative, the Natural Resources Defense Council, the Mid-Atlantic Distributed Resources Initiative, and the National Action Plan for Energy Efficiency Coalition.

A critical component in the development of demand-side management programs that help customers meet the challenges of the current high costs of energy, without conflicting with the interests of utility shareholders, is the establishment of a mechanism such as the BSA, which decouples the revenue derived from the provision of electric delivery service with the level of electricity consumption. The BSA is a sound decoupling mechanism that should stabilize distribution revenue fluctuations resulting from unanticipated changes in usage, and ensure that the Company only recovers the Board approved level of distribution costs. In essence, it should provide for decreases in delivery rates if actual revenues per customer are above the Board approved level, and it provides for increases in delivery rates if actual revenues per customer are below the Board approved level.

The decoupling mechanism creates an adjustment to customers' bills that is designed to reflect differences between Board-approved delivery revenue levels and actual delivery revenues. This is good for the customer because the Company's customers will pay only the amount determined by the Board as required to provide safe and reliable service. This is a benefit to the Company because the Company can maintain a stable revenue stream year-to-year. The mechanism should provide the Company with a stream of revenues consistent with the costs of providing safe and reliable service. The Company's costs for providing service are generally fixed, regardless of the volume of sales that the Company delivers to its customers. This proposal provides for a matching of revenues in quarterly periods, with the corresponding amounts that the Board has approved as adequate compensation for providing service. Thus, both customers and the Company are better off under the mechanism. The mechanism also protects the Company from ongoing attrition due to the reduced usage by customers. This will help avoid frequent rate cases and the attendant costs.

The decoupling mechanism will promote demand-side management measures. In this filing, the Company is proposing utility implementation of energy efficiency, conservation, and demand response programs for all customers, as part of an overall response to the recent increases in supply prices, concerns over the adequacy of supply, and increasing environmental concerns related to power plant air emissions. Demand-side management programs reduce sales and, consequently, revenues and fixed cost recovery decline. This creates a disincentive for the utility to consider demand-side resources. The existing rate structure provides strong financial incentives for utilities to sell as much electricity as possible in order to maximize profit. The decoupling mechanism removes the incentive for the Company to maximize its sales in order to benefit shareholders. Without a decoupling mechanism, the Company's shareholders benefit with each additional kWh delivered. With a decoupling mechanism, the link between increased sales and profits is broken. The Company's interest in helping its customers use energy wisely and efficiently no longer seems at odds with the interests of shareholders. By decoupling the Company's revenues from changes in the volume of electricity delivered to customers, decoupling aligns the Company's interests with the interests of the customer.

The issues described above are not unique to ACE; many other utilities across the country, both gas and electric, are in a similar position, and have developed a variety of approaches to address the over-recovery and under-recovery issue and the disincentive towards demand-side resources. The issue of the mis-match between the structure of costs and rates has long been faced by gas distribution utilities, since gas unbundling preceded electric unbundling.

Hence, many gas distribution utilities have implemented these mechanisms. Broadly speaking, the approaches can be categorized as follows:

- Weather Normalization Clauses – riders that correct for weather related changes in usage;
- Revenue Decoupling Tariffs – riders that correct for any differences in the usage levels built into base rates;
- Return Stabilization Mechanisms – expedited rate proceedings or riders that correct for both differences in usage and differences in cost;
- Fixed Variable Rate Design – changes in base rates that shift all fixed costs into fixed rate elements; and
- Increased Customer Charge – shift additional fixed costs in the customer charge.

In principle, rate structure changes that collect all of the fixed costs in a fixed charge would provide for the best alignment of costs and rates. That approach would, however, significantly increase rates for small usage customers. Stabilizing the return also addresses the problem, but removes the incentive for a utility to manage costs. While different approaches to address this issue have strengths and weaknesses, the BSA mechanism is particularly appropriate. The BSA approach represents an appropriate balance between the objectives of cost alignment, gradualism and efficiency.

It is important to keep in mind that the BSA mechanism would only be applicable to the distribution portion of the customer's bill; currently, the distribution portion accounts for only 18% of the average residential customer bill. The supply portion of the bill, which accounts for almost 60%, would not be subject to the mechanism. This has several important ramifications. First, customers still have a strong incentive to use energy efficiently, based on the savings associated with the supply side of the bill. Second, by being applicable to only the distribution portion of the bill, the mechanism should create minimal fluctuation in the total amount of a customer's bill.

When implemented, a well designed distribution rate decoupling mechanism, such as the BSA, should have the following impact: 1) customer bills will be more stable; 2) revenues will be better aligned with costs; 3) disincentives toward energy efficiency will be reduced; and, 4) the Company will be better able to recover its fixed costs.

In summary, a well designed decoupling mechanism should address the following issues and include the following features:

- Provide a stable means for the recovery of essentially fixed costs, while maintaining an overall rate structure which is dependent on volumetric components.
- Position the Company in an economic and financial position to be a strong advocate in the promotion of energy efficiency and conservation initiatives.
- Provide customers with reasonably stable bills over the course of a year. The mechanism should appropriately consider each service classification on an individual basis. Additionally, an effort should be made to identify and exclude rate classes which, due to size or usage characteristics, may not benefit from the mechanism.

ACE is prepared to present its specific recommendations regarding appropriate electric utility decoupling mechanisms to New Jersey policy makers within a Board established distribution utility decoupling working group in the near-term.

B. AMI Adjustment Mechanism

The deployment of AMI technology will require the removal and disposition of existing meters that are not fully depreciated and may require replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure. To encourage the implementation of this new technology, the Board should adopt ratemaking policies that remove a utility's disincentive toward demand-side resources that reduce throughput. The Board should provide for timely cost recovery of prudently incurred AMI expenditures in order to provide cash flow to help finance new AMI deployment.[35]

ACE requests that a base rate electric adjustment mechanism ("AMI Adjustment Mechanism") be adopted to recover the capital costs associated with the installation of the AMI on a timely basis between base distribution rate cases. Specifically, the AMI Adjustment Mechanism would be set annually on the basis of total project expenditures during the previous 12 month period. ACE proposes to net utility cost savings[36] resulting from AMI deployment from the cost recovery sought each year. ACE requests that the cost of retiring all existing meters be recovered through the AMI Adjustment Mechanism over a three to five year period to recover stranded costs. ACE's rate of return on any unamortized expenditures would equal the Company's approved rate of return. The amount of the AMI Adjustment Mechanism would vary by customer class, reflecting any AMI or smart thermostat cost differences. These costs will be offset by energy cost reductions, utility cost reductions, and service quality improvements. The

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[35] ERE-1 *Resolution to Remove Regulatory Barriers to the Broad Implementation of Advanced Metering Infrastructure*, Adopted by NARUC Board of Directors on February 21, 2007, NARUC Winter Meetings, Washington, DC.

[36] Expected utility cost savings are detailed in **Exhibit B –** the ACE AMI business case.

amount of the AMI surcharge could be reset to zero at the conclusion of each base electric distribution rate case when electric base distribution rates are reset.

An alternative utility cost recovery approach could be obtained through electric base rate case filings; however, this mechanism has the significant disadvantage of delaying the timing of ACE's cost recovery for a significant capital cost project, and having a potentially adverse impact upon the Company's cost of capital.

C. Direct Load Control Programs

ACE proposes to recover program costs through the existing System Control Charge ("SCC") across all electric distribution customers. The Company proposes that program capital costs be recovered over a fifteen year period[37] to avoid significant customer bill impacts and that interest expense on unrecovered capital costs equal ACE's allowed rate of return. A fifteen year recovery period is recommended due to the increasing obsolescence rate of one-way direct load control technology. ACE proposes to annually adjust its SCC rates for this program effective January 1st of each year through an annual cost recovery filing. The Company recommends program cost recovery through the SCC beginning after Board approval of ACE's proposed program. If the Company's cost recovery proposal is accepted, the SCC would be adjusted from its current amount of $0.000066 to $0.000085 beginning in early 2008, representing a residential customer bill increase of approximately $0.08 per month. ACE is willing to discuss alternative cost recovery mechanisms with the Board Staff. In PHI's other jurisdictions, PHI has

[37] ACE recommended that program costs be expensed over a one year period in its August 20, 2007 New Jersey Direct Load Control Program Proposal Filing, Docket No. EO06040297. This recovery period was recommended at that time to facilitate near-term Board approval of that proposal; however the Board has not established a schedule for considering the proposal as of this time. Therefore, it appears that additional time available to consider a longer recovery period for these utility investments that will further lessen the monthly distribution bill impact on ACE's customers.

recommended that cost recovery of DLC equipment be recovered through an AMI surcharge because of the unavailability of a SCC equivalent mechanism in those jurisdictions.

D. Large Customer Internet Platform, Low Income Programs, Solar Programs, Comprehensive Energy Saving Pilot Program and New Utility Provided DSM Programs

ACE proposes to recover its costs related to establishing a large customer Internet-based platform, additional low income conservation programs, and its customer solar program through New Jersey's existing SBC. The Company proposes to recover program costs through an annual filing detailing program costs to the Board. It would be appropriate to recover program costs over a five year period with interest on unrecovered costs set at the utility allowed rate of return. This longer recovery period would ensure that costs to consumers are more closely related to the stream of resulting financial benefits. The existing Board practice of expensing DSM related costs significantly lessens the quantity of funds available to support these initiatives.

VIII. MID-ATLANTIC POWER PATHWAY TRANSMISSION PROJECT

The majority of ACE's Blueprint plan is focused on the implementation of demand-side programs or distributed generation programs. However, a comprehensive plan to meet the energy requirements of southern New Jersey must include the development of adequate transmission supply. Participation rates and the success of voluntary demand-side management and distributed generation initiatives are uncertain. Even with all of these initiatives, the transmission system must be enhanced to support and complement these efforts. Therefore, additional transmission supply resources must be built to ensure that the future electricity demand in southern New Jersey is served reliably to sustain future economic growth.

Another need for transmission enhancements is to move the energy around the state and respond to changing generation patterns. As generation is retired to comply with environmental regulations, the transmission system must be capable to deliver the energy from other facilities without any restrictions or limitation. In addition, a robust transmission system will support the growth of renewable energy sources – providing the ability to transmit power generated by dispersed renewable generation while reducing the cost for interconnection of these facilities to the transmission system.

PHI and Atlantic City Electric are meeting this need by constructing a 230 mile 500kV transmission line from Southern New Jersey across Delaware and Maryland and interconnecting into the existing transmission system in Virginia. This line has been termed the Mid Atlantic Power Pathway, MAPP. MAPP will provide increased energy import capability from several existing and proposed nuclear power plants and support the expansion of the existing nuclear plants in southern New Jersey. In addition, MAPP will increase the reliability of the transmission system within the State, reduce transmission congestion cost and provide a path for future renewable energy generation facilities. PHI's proposed MAPP transmission project was approved by the PJM Board of Managers on October 17, 2007 for inclusion in the PJM Regional Transmission Expansion Plan.

IX. CONCLUSION

ACE welcomes the opportunity to work with the Board, the Division of Rate Counsel and other New Jersey electricity market stakeholders to implement each of the elements of the Blueprint for the Future. Full and prompt implementation of ACE's Blueprint Plan will help the Board and New Jersey policymakers achieve many of the energy goals that are expected to be reflected in the New Jersey Energy Master Plan. Additionally, ACE customers will benefit through improved distribution service, greater ability to control energy costs, reduced power plant air emissions, and sustained reliability of electricity supply.

EXHIBIT
B

EXHIBIT B

Advanced Metering Business Case Including Demand Response Benefits

Report for New Jersey

Before The New Jersey Board of Public Utilities

November 19, 2007

Executive Overview and Conclusion

Overview

As demonstrated in the following report, the Advanced Metering Infrastructure ("AMI") business case for Atlantic City Electric ("ACE" or "the Company") is justified by the operational benefits and the demand response benefits to the Company and our customers. Pepco Holdings, Inc. ("PHI"), the parent company of ACE, Delmarva Power & Light Company ("Delmarva"), and the Potomac Electric Power Company ("Pepco") has developed a Blueprint for the Future Plan for each of its electric distribution companies that addresses important local and national energy challenges: the rising cost of energy, the need for reliable electricity supply, and the negative impact of energy use on the environment. The ACE Blueprint Plan will be submitted to the Board of Public Utilities ("BPU") in November of 2007 and this document is provided as a supporting document to that filing.

PHI's electric distribution companies are uniquely positioned to play a leadership role in helping to meet these challenges. The ACE Blueprint builds on the work we already have begun through PHI's "Utility of the Future" planning process and other initiatives. In summary, ACE's Blueprint focuses on implementing advanced technologies together with various programs to improve service to our customers and enable them to better manage their energy use and costs. Implementation of the Plan will enable ACE to provide tools for New Jersey customers to control their energy costs and usage. ACE's Blueprint Plan will make a sizeable contribution to meeting the nation's energy and environmental challenges, help New Jersey to advance many of the proposed Energy Master Plan ("EMP") goals -- helping customers keep their electric and natural gas bills as low as possible.

ACE is deploying a number of innovative technologies. Some, such as the automated distribution system, will help to improve reliability and workforce productivity, while others, including AMI, will enable our customers to monitor and control their electricity use, reduce their energy costs and enable their participation in innovative rate options. Here are some examples of what's planned:

Demand Side Management (DSM) Programs

ACE is working closely with other New Jersey electricity market stakeholders to develop additional demand-side management initiatives in New Jersey to support the New Jersey Energy Master Plan. The

Company's Blueprint initiatives include utility provision of energy efficiency and conservation programs that are designed in collaboration with the BPU and other market stakeholders to assist New Jersey achieve its aggressive energy reduction goals, universal deployment of an AMI System to all ACE customers to support the collection of energy consumption data, ACE provision of critical peak charge or critical peak rebate pricing to encourage customers to reduce their electricity use during times of high electricity demand and high prices, ACE deployment of a an AMI enabled smart thermostat system to reduce summer peak electricity load and reduce annual overall energy consumption, and ACE deployment of an internet-based platform to facilitate large customer participation in the PJM demand response market. Peak electricity demand reduction programs are a critical component of ensuring the adequacy of electricity supply in New Jersey, helping customers to lessen their energy costs, and mitigating regional high wholesale electricity prices.

Automated Metering Infrastructure (AMI)

ACE will work collaboratively with the Commission and other market stakeholders to phase in the installation of an AMI system in the businesses and homes of ACE electric customers. The AMI system will provide detailed usage data to our customers, our electricity suppliers and to the Company. The system will not only enable customers to track and modify their electric use, but it will also help us make improvements to customer reliability, outage management, and billing accuracy and timeliness.

Environmental Considerations

The deployment of an AMI System will support innovative customer rate options that help to support plug-in vehicles and small-scale renewable generators. As part of PHI's numerous environmental initiatives, PHI is laying the groundwork to transform its 2,000-vehicle fleet to more environmentally friendly technologies. The Company already using Biodiesel at PHI fueling sites; we have replaced a number of our fleet vehicles with hybrid vehicles; and we are collaborating with the Electric Power Research Institute ("EPRI") on a project to demonstrate plug-in gasoline/electric vehicles. PHI has launched a green buildings initiative to lessen the environmental impact of its facilities.

In addition to these programs, the significant demand response efforts enabled by this technology will allow for reduced dependence on peaking sources of generation, while the technology will improve our access to greener sources of supply.

Components of ACE AMI Business Case

The Business Case is comprised of four major components: Energy Delivery Benefits from AMI, Customer Savings from Reductions in Peak Loads, Cost to Deploy, and Accelerated Depreciation. The information contained in each of these components is further described below and detailed in the body of this report.

1 - Energy Delivery Benefits from AMI

Savings in operating costs captures O&M and capital savings expected to be realized once the AMI is implemented. These savings or benefits will include:

- Meter Related Benefits
- Customer Contact Benefits
- Asset Optimization Benefits
- Additional Benefits

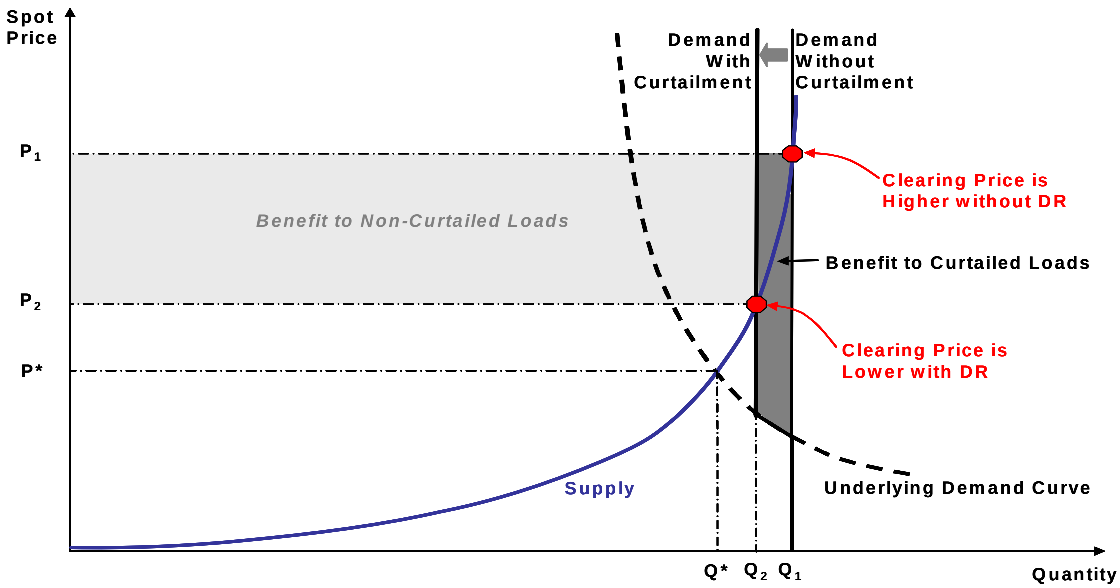
2 - Customer Savings from Reductions in Peak Loads

This analysis estimates the cost savings ACE's AMI enabled demand response programs are likely to achieve by (1) reducing the need for capacity, energy, and ancillary services (i.e., the "resource cost savings"); and (2) depressing market prices for energy and capacity by reducing demand. **The benefits are estimated consistently with the January, 2007 *Brattle* Study, "Quantifying Demand Response Benefits in PJM," sponsored by PJM and the Mid-Atlantic Distributed Resources Initiative ("MADRI"), with several additional analytical elements.**

The resource cost savings reflects the fact that every MW reduction in peak load lessens the need for physical capacity, which customers pay for through the load serving entities' payments. Similarly, every MWh reduction in consumption lessens the quantity of generation that customers must buy during peak periods with very high prices.

Furthermore, in today's New Jersey electricity market, electricity market demand response is inadequate, resulting in higher commodity prices during periods of electricity peak demand than would otherwise exist. It is essential to any properly functioning market, that both the supply and demand side of the market are fully operational. In general, the market price impacts reflect the fact that even a small reduction in demand during tight market conditions lowers the market price for energy, thus lowering the cost of energy for all customers (not just those curtailing load), as illustrated in Figure 1. Similarly, reducing the peak demand lowers the demand for capacity and thus reduces market prices for capacity, which affects all customers.

Figure 1: The *Brattle*-PJM-MADRI Study Demonstrated How Even Small Changes in Demand Can Lead to Large Changes in Prices and Customer Benefits



3 - Cost to Deploy

Cost to Deploy includes the cost of the capital investments associated with building out the AMI system. Deployment costs included are; meters and installation, communications network infrastructure and installation and the associated information technology systems and integration, including the meter data management system ("MDMS"). Also included in the Cost to Deploy are the Incremental operating cost for the AMI system. Incremental operating costs include O&M expenses associated with operating the AMI. This includes; MDMS Software, Maintenance and license fees, AMI network management software maintenance and license fees, hardware lease expense for application and storage servers and expenses related to the communications network infrastructure.

4 - Accelerated Depreciation

The deployment of AMI technology will require the removal and disposition of existing meters that are not fully depreciated and the replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure. These impacts have been reflected in the analysis. Depreciation calculations may be updated if to pending Federal legislation is enacted.

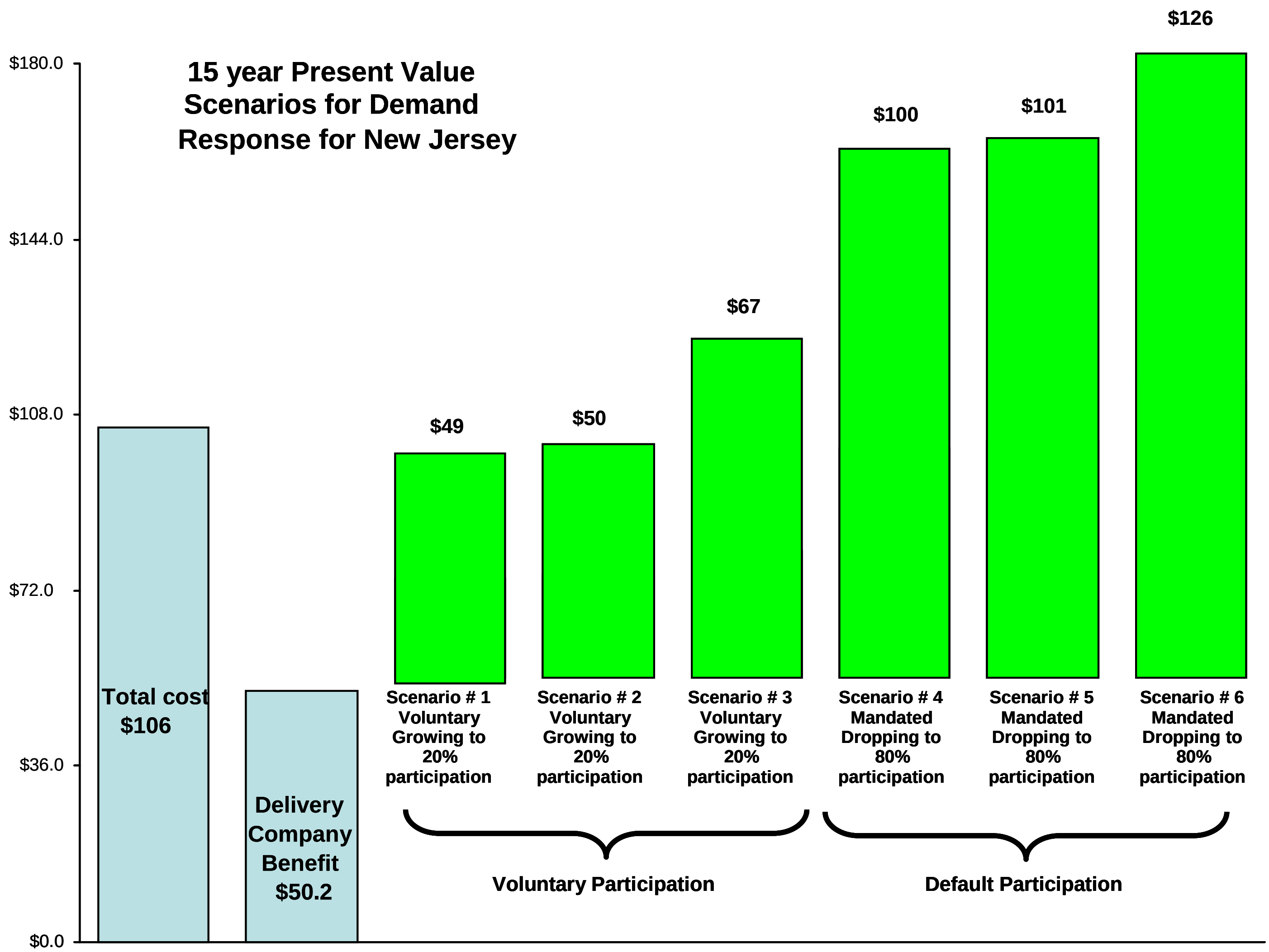
Conclusions

The ACE AMI business case is justified by the operational benefits and the demand response benefits to the Company and our customers. The estimate for demand response financial benefits from the AMI deployment, over a 15 year period, is $55.3 million estimated using the average of the *three most conservative scenarios*. Coupled with operational financial savings of $50.2 million, results in approximately a net zero Present Value Revenue Requirement ("PVRR") over the same period. AMI provided distribution service quality enhancements, which are difficult to quantify, will provide significant benefits for ACE customers. If AMI enabled demand response is widely adopted across the mid-Atlantic PJM market, savings are expected to range between $100 million and $126 million – an incredible savings for electricity consumers in the mid-Atlantic region.

atlantic city electric
A PHI Company

EXHIBIT B

Figure 2



In order to arrive at this conclusion, PHI contracted with the Brattle Group to develop six scenarios of customer and supplier response to AMI. Figure 2 above, shows the relationship of each of these six scenarios compared to the PVRR Cost and Benefit. These conditions include possible fluctuations in fuel prices, and or high peak years (usually weather driven). Following PHI's example, if the other energy distributors in PJM deploy AMI, the benefit to New Jersey customers is estimated to be as high as $349 million.

The results of this analysis yields two key conclusions: (1) AMI has a net zero investment if the average of the most conservative AMI valuation scenarios are assumed; (2) the benefits from AMI-enabled DR will be more than twice as large if dynamic pricing is the default rate structure than if it is merely an option that customers can elect.

Figure 3 below summarizes the PVRR for ACE New Jersey.

Figure 3

Line	AMI System Components		Initial Deployment Costs Only, $ in 000s New Jersey
1	Meters, including Installation Cost	$	80,471
2	Communications Network, including Installation Cost	$	39,323
3	AMI Network Management System and Meter Data Management System	$	7,881
4	Contingency	$	1,021
	Total Capital Expenditures	$	128,696
	AMI System Incremental Cost to Operate		**Annual Estimated Costs After Deployment, $ in 000s New Jersey**
5	MDMS Software Maintenance & License Fees	$	110
6	MDMS Hardware Leasing	$	300
7	AMI Network Management System O&M	$	355
8	Communications Network Infrastructure O&M	$	452
	Total Incremental Cost to Operate	$	1,217

15 Year Revenue Requirement of Total Costs	***$106 million***

Atlantic City Electric Company			In Projected 2008 Dollars, $ in 000s	Benefit Dollars as a % of Total
Line	**Benefit Category**		**New Jersey**	**New Jersey**
1	Eliminate Manual Meter Reading Costs	$	3,799	49.0%
2	Implement Remote Turn-on/Turn-off Functionality	$	1,705	22.0%
3	Improve Billing Activities	$	875	11.3%
4	Reduce Off-Cycle Meter Reading Labor Costs	$	657	8.5%
5	Asset Optimization	$	366	4.7%
6	Reduce Expenses Related to Revenue Protection	$	122	1.6%
7	Eliminate Hardware, Software, Maintenance and Operations Cost for the Itron Handheld Data Collection System	$	138	1.8%
8	Reduce Volume of Customer Call Types Related to Metering	$	53	0.6%
9	Improve Complaint Handling	$	44	0.5%
10	Total	$	7,759	100.0%

15 Year Revenue Requirement of Operating Benefits	***$50.2 million***

Business Case Report Details

Organization of this Report

For the preparation of this report, PHI gathered information from both internal and external subject matter experts, including IBM and the Brattle Group, as well as from other utilities across the country. This report represents the current state of thinking for AMI deployment. Specific points underlying this analysis are:

- AMI Capital Costs reflected in this report represent current best estimates. After PHI secures an AMI Vendor(s), the final Capital Cost numbers will be refined and updated.
- This Business Case assumes the deployment of an AMI system throughout all PHI jurisdictions.
- Cost and Benefit estimates are realistic yet conservative to assure a high probability of achievement.
- While many benefits are immediately available as the AMI System is deployed, timing of the full benefits associated with an AMI system is assumed to begin following the complete deployment.
- Business Case Financial Assumptions:
    - 15 year Present Value Revenue Requirement model, with multiple jurisdictions modeled
    - Meter Deployment assumed 100% of meters by 2012:
    - Meter growth is assumed to be 1% per year
    - 3% labor and expense annual escalation rate
    - Cost of Capital
        - Atlantic City Electric: 6.69% (after tax)
    - Income tax rate 40.85%
    - Depreciation:
        - New meter and meter communications equipment - 15 yrs

- Existing meter and equipment – 5 years
- IT Capital Cost - 5 years

Energy Delivery Benefits from AMI

This section of the report describes the estimated benefits[1] that will be realized by Atlantic City Electric through deployment of the advanced metering infrastructure system and the associated meter data management system. Typically, the full value realized from the benefits is expected to occur after full deployment of the AMI system. These quantified benefits are expected to help offset the costs associated with the deployment of AMI and MDMS. Figure 4 below summarizes the annualized benefits and under the Figure are more detailed descriptions of each benefit.

Figure 4 (In $ Thousands)

Atlantic City Electric Company		In Projected 2008 Dollars, $ in 000s	Benefit Dollars as a % of Total
Line	Benefit Category	New Jersey	New Jersey
1	Eliminate Manual Meter Reading Costs	$ 3,799	49.0%
2	Implement Remote Turn-on/Turn-off Functionality	$ 1,705	22.0%
3	Improve Billing Activities	$ 875	11.3%
4	Reduce Off-Cycle Meter Reading Labor Costs	$ 657	8.5%
5	Asset Optimization	$ 366	4.7%
6	Reduce Expenses Related to Revenue Protection	$ 122	1.6%
7	Eliminate Hardware, Software, Maintenance and Operations Cost for the Itron Handheld Data Collection System	$ 138	1.8%
8	Reduce Volume of Customer Call Types Related to Metering	$ 53	0.6%
9	Improve Complaint Handling	$ 44	0.5%
10	Total	$ 7,759	100.0%

1) Eliminate Manual Meter Reading Costs

This is the largest operational benefit expected to be realized after full deployment of the AMI system. ACE uses an outside contractor to read its meters in New Jersey which would no longer be needed to perform its present functions after full deployment of AMI. As of the date of this report, which is prior to development of the request for proposal for the procurement of the AMI system, the Company expects to design and configure its AMI System in a manner that all New Jersey customers will

[1]The quantification of these benefits will change as Atlantic City Electric conducts the procurement phase of its AMI project and evaluates the capabilities of the various AMI systems available in the market today. In addition, the quantifications will also change due to changing labor rates, payroll loading rates, inflation and other possible changes in the underlying assumptions used to derive the estimated value of the benefits.

receive meters that are reachable by the AMI's communications network infrastructure. The elimination of the need to manually read meters will result in annualized O&M expense savings of $3.8 million (expressed in projected 2008 dollars). The O&M expense savings estimate is based upon projected meter reading volume multiplied by the per read rates specified in the contract with the outside contractor.

The initial year was assumed to be 2008, therefore the 2007 O&M expense savings as described above were escalated three percent to account for expected wage and inflation increases. The three percent escalation factor was similarly used to grow the estimated annualized savings in the remaining years of the revenue requirements schedule

2) Implement Remote Turn-on/Turn-off Functionality

The Company's current assumption is that a switch will be available inside the meters that will permit the Company to remotely connect and disconnect 200 AMP and lower electric service. This assumption is consistent with plans of other utilities and requirements of other state public service commissions, including the Maryland Public Service Commission that oversees ACE's affiliated electric distribution companies, Pepco and Delmarva.

The estimated savings associated with this benefit is comprised of two components. First, there will be savings from avoiding field visits to customers' premises conducted at the customers' requests to turn-on or turn-off electric service. Based upon a review of 2006 data from the Company's accounting system, there were approximately 12,000 labor hours used for residential turn-on and turn-off orders. This translates into approximately eight to nine Full Time Equivalents ("FTE"). The FTE employee concept was used instead of specific personnel since a mix of employees performs this type of work. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE, taking into account the cost mix of employees performing the work. The loading rate applied to the labor cost includes payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The savings also include reduced cost of vehicles and miscellaneous expenses.

The fully loaded annual labor costs included the same costs that were described in the meter reading benefit, as described above. This portion of the savings amounted to an estimated annualized $0.9 million (expressed in projected 2008 dollars).

The second component of the savings will come from avoiding field visits to customers' premises for collection reasons, both the initial cut/collect field visit and the reconnection field visit, if such a reconnection visit was requested by the customer. Based on a review of 2006 data from the Company's accounting system, there were approximately 12,000 labor hours required for residential field collection and reconnection visits. This translates into approximately eight to nine FTEs. Full time equivalents were used instead of specific personnel since a mix of employees does this type of work. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE, which took into account the cost mix of employees doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit, as described above. This portion of the savings amounted to an estimated annualized $0.8 million (expressed in projected 2008 dollars).

Remote turn on/turn off capability will benefit all customers, especially those subject to disconnection for non-payment. Currently the Company's tariff specifies on Rate Schedule CHG that the charge for a disconnection is $15.00 and that the charge for a reconnection is $15.00 during normal working hours (after normal working hours the charge is actual costs). The total charges of $30.00 could be reduced (estimated in the range of $5 to $10) with AMI's remote connection and disconnection functionality, The reconnection could be accomplished remotely from the Company's offices, after the customer calls the Company to verify payment, rather than dispatching a person to the customer's premise. This reduces the financial burden on those having difficulty paying their bills. This method is also safer for employees who perform this type of work.

3) Improve Billing Activities

With the deployment of AMI, the Company expects to significantly reduce the volume of exceptions that it currently addresses in its billing department. These exceptions include such transactions as estimated bills, consecutive estimations, high/low consumption and other checks. Atlantic City Electric and Delmarva Power operate their billing department on an integrated basis using the same customer information system ("CIS"). As of June 2007, Atlantic City Electric and Delmarva employed a total of 28 billing analyst and supervisory personnel to handle the exceptions work volume. For this benefit, Atlantic City Electric assumed 90% of the work performed by these personnel would be eliminated with full deployment of AMI which translates into the elimination of the cost of 25 full time equivalents. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees (analysts and supervisors) doing the work. The fully loaded annual labor costs included the same costs that were described in the remote turn-on/turn-off benefit, as described above. This portion of the savings amounted to an estimated annualized $1.9 million (expressed in projected 2008 dollars) for all of Atlantic City Electric and Delmarva combined. Note that if less than 90% of the exception volume is ultimately realized, then the savings estimate will be adjusted accordingly.

The savings were allocated between Atlantic City Electric's, Delmarva's Delaware electric and gas types of service, and Delmarva's Maryland jurisdiction using a 2007 average budgeted customer counts as the allocation factor. This allocation factor is presented in the Figure below.

Figure 5

Allocation based on 2007 Budgeted Customer Counts			
ACE	543,437	47%	$ 849,577
Delmarva-DE-Electric	296,159	26%	$ 469,979
Delmarva-DE-Gas	119,403	10%	$ 180,761
Delmarva-MD	200,350	17%	$ 307,294
Combined	1,159,350	100%	$ 1,807,611

The 2007 dollars in Figure 5 above were escalated by three percent (3%) to account for 2008 estimated wage increases which increases the dollars in Figure 5 from $1.8 million to $1.9 million.

4) Reduce Off-Cycle Meter Reading Labor Costs

The Company uses service persons to obtain meter readings outside of the normally scheduled meter reading routes for a variety of reasons. These reasons include when a customer moves out of a premise and a new customer moves in shortly thereafter and asks the billing department or the call center to check a reading in the field. With the full deployment of AMI, these "check reads" can be obtained remotely from the Company's offices eliminating the need for a field visit.

Based on a review of 2006 data from the Company's accounting system, there were approximately 7,400 labor hours used for electric meter "check reads". This translates into approximately five to six (5 to 6) full time equivalents for electric meters. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees doing the work. The fully loaded annual labor costs included the same costs that were described in the remote turn-on/turn-off benefit above. This portion of the savings amounted to an estimated annualized $0.7 million (expressed in projected 2008 dollars).

5) Asset Optimization

AMI deployment will improve the quality of customer outage status and hence will reduce the field restoration efforts associated with "false" power outages. ACE experiences approximately 1800 power outage calls annually where upon arrival at the customer locations, the emergency response team finds that there is no electric service problem related to ACE but the problem is on the customer side of the meter or in the house. Similarly, during storms, the Company responds to approximately 800 outage requests annually which have been already restored previously but not recorded in the Company outage management system. AMI capabilities will eliminate these unproductive trips as well as reduce the number of Call Center calls and will result in estimated savings of $290,000. AMI deployment also will improve ACE's asset management program and will result in accurate sizing of transformers and fuses. This will result in reduced outages and is expected to reduce number of field trips by 400 annually. It will also reduce field trips associated with special load readings at substations. The savings associated with this benefit is $ 65,000 annually.

6) Reduce Expenses Related to Theft of Service

The Company currently uses an outside firm to analyze commercial account data to provide internal field investigators with selected accounts that may be experiencing tampering, energy diversion or some sort of metering problem. Based upon discussions with MDMS vendors, it appears that with data coming from the AMI system coupled with analytical capabilities of the MDMS, the Company will be better equipped to conduct these types of analyses internally and could therefore eliminate this contractual relationship. The savings were allocated between Atlantic City Electric's, Delmarva's Delaware electric and gas types of service, and Delmarva's Maryland jurisdiction using a 2007 average budgeted customer counts as the allocation factor.

7) Eliminate Hardware, Software, Maintenance and Operations Cost

ACE and Delmarva currently pay maintenance fees on their existing hand-held metering reading devices and also employ two employees to operate and maintain the devices and associated data. With the deployment of AMI, these costs would be eliminated. The O&M expense savings for the two employees is based on the actual 2007 salaries of the two people with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The savings were allocated between Atlantic City Electric's, Delmarva's Delaware electric and gas types of service, and Delmarva's Maryland jurisdiction using a 2007 average budgeted customer counts as the allocation factor.

8) Reduce Volume of Call Types Related to Metering

PHI operates its call centers for Atlantic City Electric and Delmarva on an integrated basis using the same customer information system. In 2005 and 2006, PHI received about 40,000 customer calls related to metering. If this associated call volume were reduced after the full deployment, the call center could save two full time equivalents. The O&M expense savings for the FTEs is based on the actual salary for a customer service representative with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits multiplied by two FTEs. The savings were allocated between Atlantic City Electric, Delmarva's Delaware electric and gas types of service, and Delmarva's Maryland jurisdiction using a 2007 average budgeted customer counts as the allocation factor.

9) Reduced Complaint Handling

PHI operates its complaint handling group for Atlantic City Electric and Delmarva on an integrated basis using the same customer information system. For this benefit, PHI is assuming the data from AMI will, over time, contribute to fewer complaints and that the company representatives may be able to more quickly to resolve complaints. The current assumption is that the complaint handling group may be able to reduce one full time equivalent. The O&M expense savings for the one FTE is based on the actual salary for a company representative with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The savings were allocated between Atlantic City Electric, Delmarva's Delaware electric and gas types of service, and Delmarva's Maryland jurisdiction using a 2007 average budgeted customer counts as the allocation factor.

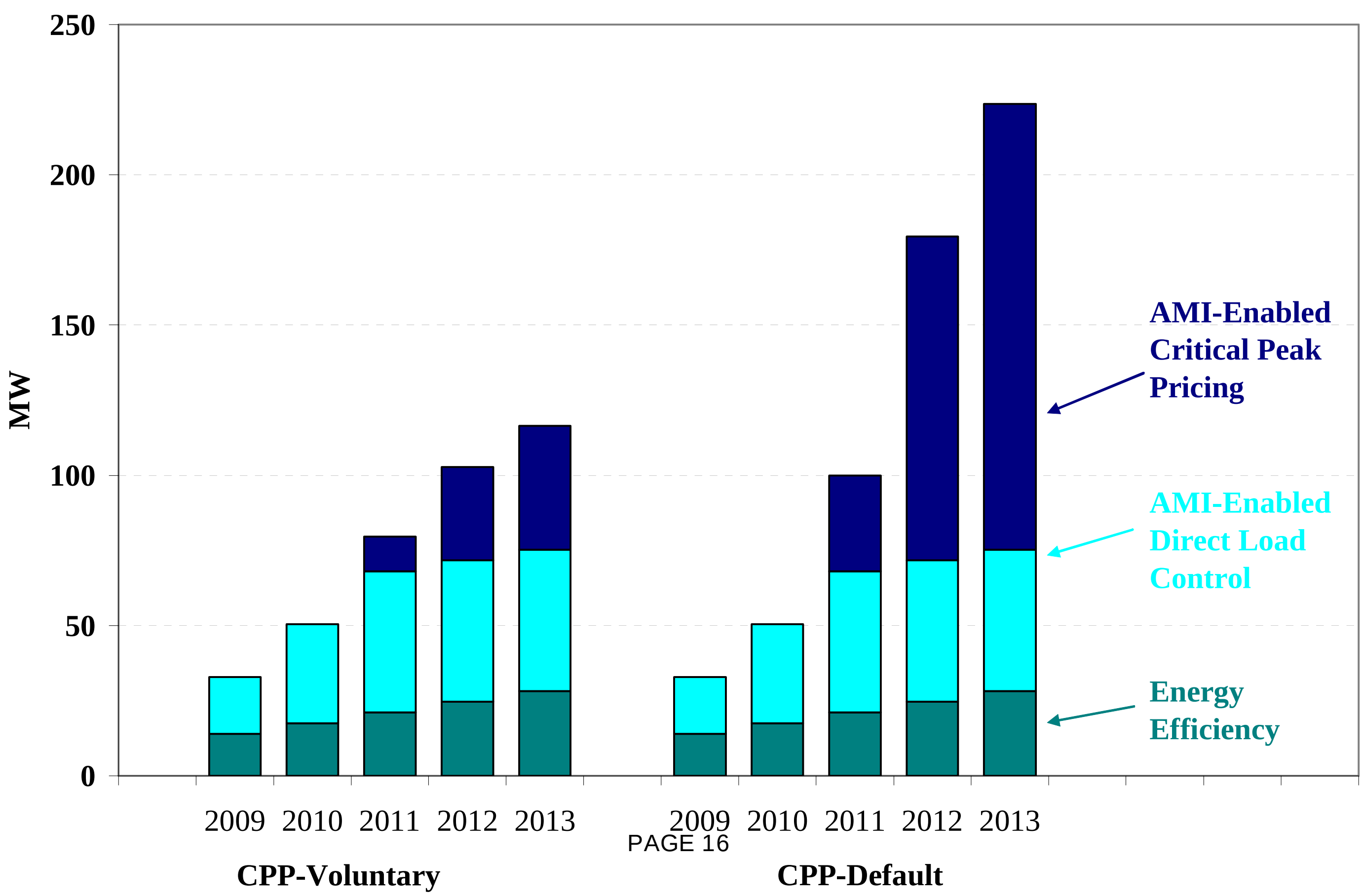
Customer Savings from Reductions in Peak Loads

The Brattle Group was retained by PHI to estimate the value to customers of load reductions resulting from PHI's proposed investments in demand-side management (DSM) initiatives, including energy efficiency, direct load control, and deployment of advanced metering infrastructure. *Brattle*'s analysis involves two major components: first, determining the magnitude of load reductions that are likely to be achieved; and second, estimating the customer value of such load reductions.

1) Estimated Load Reductions

Load reductions associated with PHI's proposed programs involving energy efficiency and AMI-enabled direct load control are taken directly from PHI's most recent Blueprint Filing for its DSM programs. Load reductions associated with AMI-enabled critical peak pricing ("CPP") programs were estimated using the PRISM model, which is based on empirical data from the California Statewide Pricing Pilot and is calibrated to the load characteristics of residential and small C&I customers in ACE New Jersey. Assuming a CPP program similar to Pepco's District of Columbia current CPP pilot becomes the default rate structure with 80% of eligible customers participating, the resulting load reductions would likely be quite substantial. These load reductions would be less substantial if participation were voluntary. Figure 7 below shows the estimated load reductions for both Voluntary and Default rate structures.

Figure 7 - Estimated Peak Load Reductions for New Jersey from PHI's Initiatives, Assuming CPP is the Default Rate Structure (MW)



2) Analysis of Customer Benefits from Load Reductions

Savings to the customer relates to those benefits that will reduce the customer's bill, but not impact the cost of energy delivery. Most significantly, AMI-enabled innovative rate options (e.g., critical peak pricing, time of use rates, real-time pricing, etc.) will allow the customer to better manage consumption and thus reduce demand during peak periods. Reductions in peak consumption will produce savings by (1) reducing the need for supply-side capacity, energy, and ancillary services (i.e., the "resource cost savings"); (2) depressing market prices for energy and capacity by reducing demand; (3) reducing transmission losses; (4) improving reliability; (5) reducing rate volatility; (6) enhancing market competitiveness; (7) improving environmental quality or reducing energy prices by lowering the costs of environmental compliance; and (8) potentially obviating or delaying the need for investments in transmission and distribution.

The customer benefits detailed in this report focus on items one and two, above. The other categories of benefits have not been quantified because the economic methodologies involved are not well developed or standardized. Therefore, the total benefits of reducing load could be substantially larger than the limited set of benefits reported in this Business Case.

The Brattle Group has estimated the benefits to New Jersey customers from resource cost savings and market price impacts consistent with its January, 2007 study, "Quantifying Demand Response Benefits in PJM," sponsored by PJM and the Mid-Atlantic Distributed Resources Initiative ("MADRI"), but with several additional analytical elements.

Resource Cost Savings

Capacity savings reflect the fact that DR lowers the load forecast, which lessens the amount of capacity that load-serving entities must purchase from generation suppliers through contracts or through PJM's capacity market. Alternatively, load that is controlled directly by the utility can provide capacity, thus offsetting the need for physical capacity. The value of either approach – reducing the capacity requirement or contributing capacity – can be evaluated using a projected price of capacity. *Brattle* estimated the future capacity price using the Net Cost of New Entry ("Net CONE") that PJM uses in its definition of capacity market parameters. Net CONE is a conservative proxy because the capacity price has been higher than Net CONE in recent auctions for the 2007/08 and 2008/09 delivery years. Net CONE is also less than the avoided capacity cost often used in DSM plans, which often does not net out the marginal value (i.e., operating margins) that new generation would provide by selling energy and ancillary services.

Generation savings depends on the particular type of generation that is being avoided, which could come from a combination of new capacity not constructed and old capacity retired or not dispatched. The value of reduced generation is also partially offset by the value the customer forgoes by not consuming as much power. Assessing the forgone value to the customer is difficult to value and depends on whether the customer shifts load to lower-priced periods. These issues were addressed in the *Brattle*-PJM-MADRI study, in which generation savings amounted to an additional 12-36 percent on top of the capacity savings. Brattle's analysis of AMI-enabled DR in ACE simply adopts these figures by adding 12-36 percent of the estimated capacity savings.

Some DR could provide spinning reserves or other ancillary services ("A/S"), which would reduce the need for reserves from supply-side resources, the marginal value of which is given by the market price for spinning reserves. However, ancillary service value is somewhat speculative because currently none of PHI's DSM programs plan to enable ancillary services, although other DR does provide small amounts of A/S in PJM and ISO-NE.[2]

Short-Term Price Impacts

Short-term energy price reductions are estimated by adapting the results of the *Brattle*-PJM-MADRI study (January, 2007) to reflect the load reductions expected from PHI's programs. As in the Brattle-PJM-MADRI study, the "benefit" is given by the product of the estimated price reduction and the load exposed to market prices. Benefits are partially offset by an associated reduction in the value of Financial Transmission Rights ("FTRs") (about a 15% offset). To the extent that PHI's load reductions differ from the load reductions simulated in the *Brattle*-PJM-MADRI study, *Brattle* linearly extrapolated the price impacts (e.g., twice the amount of load reductions would lead to twice the price impact).

While the *Brattle*-PJM-MADRI study assumed that all non-curtailed load was exposed to market prices, the present analysis assumes conservatively that only a fraction of load is exposed to market prices. The

[2] *Brattle* assumed conservatively that AMI could eventually enable 100 MW of spinning reserves from loads that can be curtailed within less than 30 minutes of notification and stay offline for as much as 4 hours, such as electric arc furnaces or chillers in supermarkets. Hence potential ancillary service value is estimated by multiplying a conservative quantity of spinning reserves by the historical average price of spinning reserves (2004-06) of $8.5/MWh and by the number of hours in a year.

remainder is unaffected because it is covered by pre-existing contracts that were priced without anticipating the effects of DSM. Roughly corresponding to the contract lengths and schedules by which standard offer service is procured in DC, DE, and MD and basic generation service in New Jersey, *Brattle* assumed that in any given year 50% of load-serving obligations are supplied by pre-existing wholesale contracts, and 50% are supplied by new contracts. This assumption results in discounted customer benefits relative to the *Brattle*-PJM-MADRI study – a 50% discount in the "Immediate" Supply Response scenario and a 17% discount in the "Slower" scenario discussed below.

A second difference from the *Brattle*-PJM-MADRI study is the quantification of real-time DR benefits. The *Brattle*-PJM-MADRI study quantified benefits for only day-ahead DR and discussed qualitatively the potential additional value from DR that is dispatchable in real-time and thereby able to mitigate the effects of real-time surprises in supply and demand. In its present analysis of DSM in ACE, *Brattle* assumed that loads under direct load control were dispatchable in real time, and estimated the premium using the ratio of historical super-peak RT prices to super-peak DA prices. *Brattle* also estimated the additional value if dynamic pricing could designate peak periods on the day-of rather than day-ahead.

A third difference is that *Brattle*'s present analysis includes an estimate of the capacity price impact from DR, whereas capacity price impacts were outside the scope of the *Brattle*-PJM-MADRI. Participation of DR in capacity markets is an important element of PJM's newly instituted Reliability Pricing Model (RPM). While only the subset of load reductions, those that are under direct control (by the utility, other retail providers, curtailment service providers or the RTO), can participate as supply in capacity markets (Smart thermostat), the expected effect of dynamic pricing programs would also impact capacity prices by reducing the load forecast and thus the administratively-determined demand for capacity. Given this new market reality, *Brattle* has estimated capacity price impacts as follows: in the "Immediate" and "Slower" Supply scenarios (defined below), the market was assumed to be in supply/demand balance with the expected 3-year forward capacity price set by Net CONE, irrespective of the level of load reductions achieved. Hence, the capacity price impact was conservatively set at zero in these scenarios. In the "Delayed" Supply scenario, capacity price impacts were estimated by intersecting supply and demand curves for capacity in the Eastern MACC Locational Delivery Area both with and without DR. The demand curve was constructed using PJM's load forecast and the other parameters it uses to determine the administratively-determined demand curve. The supply curve was constructed by adding projected new supply (from the generation interconnection queue) to the supply curve available from the most recent capacity auction.

Scenario Definition

A key insight is that the resource cost savings from reducing peak loads persist over time, whereas the market price impacts can be expected to diminish as suppliers respond to depressed prices by delaying the construction of new generation or accelerating the retirement of existing plants. The magnitude and duration of the price impact depends on the rate at which suppliers respond to changes in market conditions and on the tightness of the market over the next several years. Price impacts are the largest and the longest-lasting in a scarcity situation; they are the smallest and shortest-lived in a surplus market or in a balanced market in which suppliers react quickly to DSM's successes (and associated price impacts) by delaying construction of new capacity or accelerating the retirement of existing plants. Hence, Brattle analyzed a range of plausible market conditions by constructing three supplier scenarios in which the longevity of price impacts is varied:

- In the "Immediate" scenario, the market is in supply-demand equilibrium, and suppliers react quickly to changes in fundamentals. Short-term energy price impacts, as derived from the Brattle-PJM-MADRI study which used a short-term equilibrium model in which supply is static, benefits last for only one year before suppliers fully respond to DSM. One year after the introduction of new DR, suppliers have accelerated enough retirements and/or delayed enough new construction to completely offset the price impact of DR. Hence, if PHI's deployment schedule produces a 200 MW of total peak load reduction in year n and 300 MW in year n+1, then only 100 MW of load reductions has a price impact in year n+1. This scenario is consistent with the observation that suppliers in PJM's recent RPM Base Residual Capacity Auction for the 2008/09 delivery year changed their plans relative to the prior auction (in this case delaying retirements), presumably in response to high prices in the prior auction.

- The "Slower" scenario is similar to the "Immediate" scenario except that short-term price impacts persist for three years before suppliers respond. The three-year response time corresponds to a three-year lead time for new construction.

- In the "Delayed" scenario, suppliers do not build any capacity that is not currently in PJM's queue until 2013, and the market becomes very short on capacity. In such a shortage situation, suppliers are not responsive to the introduction of DR because they have no new capacity to delay and retiring existing plants early is unlikely, hence all load reductions achieved by PHI's DSM initiatives creates price impacts until 2013. This scenario reflects the possibility that suppliers are reluctant to build in the current uncertain environment with the threats of reregulation, high gas prices, climate change policies, and siting difficulties.

Finally, each supplier response scenario is analyzed assuming high rates of customer participation in dynamic pricing programs and, alternatively, low customer participation rates. Customer participation rates depend primarily on whether critical peak pricing becomes the default rate structure or merely an option that customers can elect. In the "CPP Default Rate Structure" scenario, 100% of customers would be enrolled in a critical peak pricing rate initially, and some 20% would eventually switch to a non-CPP rate structure, leaving 80% participation in year two and beyond. In the "CPP Elective" scenario, 0% of customers would sign up initially, ramping up to 20% in two years and beyond. (These rates are based on the experience from the California Statewide Pricing Pilot and other pilots.)

3) Conclusions Regarding Customer Benefits from Load Reductions

Figure 8 shows the benefits to New Jersey customers (including municipal and cooperative utilities contained within the PHI zones) if ACE's proposed DSM programs are implemented in ACE-New Jersey according to its proposed deployment schedule.

The following conclusions can be drawn from this analysis:

- For the Default CPP Case, the quantified benefits of load reductions would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of DSM ($92-113 million for all of New Jersey), but they are be much greater in the Delayed Supply Response scenario ($203-233 million for all of New Jersey).

- For the Voluntary CPP Case, the quantified benefits of load reductions would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of DSM ($46-55 million for all of New Jersey), but they are be much greater in the Delayed Supply Response scenario ($126-142 million for all of New Jersey).

- The short-term savings to all customers, including customers outside of PHI's zones, would be much larger than the benefits to just New

Jersey customers due to the fact that PHI's load reductions would have a market-wide impact on energy and capacity prices.

Figure 8. Benefits to New Jersey Customers from AMI-Enabled Dynamic Pricing and Direct Load Control Programs in ACE New Jersey for both Voluntary and Default Cases.

Rate Structure Scenario	**CPP is a Voluntary Rate**			**CPP is the Default Rate**		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS						
Avoided Capacity Costs	$38	$38	$43	$79	$79	$88
Avoided Energy Costs	$9	$9	$10	$19	$19	$21
Ancillary Services Benefit	$2	$2	$2	$2	$2	$2
SHORT-TERM PRICE IMPACTS						
Energy Price Benefit	$0.2	$0.8	$1.2	$0.4	$1.5	$2.0
Potential Additional Real-Time Benefit	$0.1	$0.2	$0.2	$0.2	$0.3	$0.3
Capacity Price Benefit	$0	$0	$10	$0	$0	$13
AVERAGE QUANTIFIED BENEFIT **	$49	$50	$67	$100	$101	$126
UNQUANTIFIED BENEFITS						
Improved Reliability			Very Large***			Very Large***
Enhanced Market Competitiveness						
Reduced Rate Volatility						
Reduced Transmission and Distribution Losses						
Reduced Need for Investments in T&D Infrastructure						

* Immediate response: short-term benefits last for 1 year; Slower response: short-term benefits last for 3 years; Delayed response: no generic entry and short-term benefits last until 2015.
** Excluding additional potential real-time benefits.
*** A PHI-wide implementation of AMI and energy efficiency would increase reserve margins in Eastern MAAC from 18.1% to 18.9% in 2010, and from 11.5% to 12.9% in 2013 with CPP as the default rate structure, and from 18.1% to 18.6% in 2010, and from 11.5% to 12.3% in 2013 with CPP as a voluntary rate structure.

- The savings to New Jersey customers would be as much as two and a half times larger if all utilities in PJM-East followed PHI's lead in deploying DSM programs and achieved similar load reductions, with the aggregate load reductions creating a much greater impact on energy and capacity prices.

- The savings to New Jersey customers would be less than half as large if critical peak pricing were not the default rate structure, requiring customers to take initiative in order to sign up for the program. This finding is based on the assumption that a voluntary program would achieve only 20% participation by residential and small commercial and industrial customers, whereas making CPP the default rate structure with an option to switch to a fixed rate would achieve 80% participation. (This assumption is consistent with participation rates in California's Statewide Pricing Pilot.) However, even at a conservative 20% participation rate, the total benefits of AMI/DSM could exceed the total costs.

- Although critical peak pricing programs typically designate peak periods on a day-ahead basis, making the programs callable on a real-time basis would enable customers to mitigate the impacts of real-time surprises in load or supply outages. This could add an additional $100,000 to $300,000 in value.

- In the Delayed Supply Response scenario, implementation of DSM programs like PHI's throughout PJM-East would increase reserve margins in Southwest MACC from 15.2% to 18.3% in 2010, and from 5.8% to 14.4% in 2013; in Eastern MAAC from 18.1% to 21% in 2010 and from 11.5% to 19.9% in 2013. Hence, DSM initiatives would provide substantial value as an insurance against intolerably low reserve margins.

- These estimates of customer benefits are likely to be conservative due to the limited scope of benefits quantified. Furthermore, the largest component of the estimated benefit, the avoided capacity costs, is probably understated because it is based on a historical Net Cost of New Entry that does not account for the recent dramatic worldwide upswing in the cost of all kinds of new generation. On the less conservative side, it is possible that the Inadequate Supply Response scenario exaggerates the looming supply shortage in Southwest and Eastern MAAC by assuming zero entry of capacity that is not yet planned until 2014. The scenario was constructed to demonstrate the potential value of DSM in a severely supply-constrained situation.

These savings estimates do not include potential additional customer benefits from reducing transmission losses, improving reliability, reducing rate volatility, enhancing market competitiveness, improving environmental quality, reducing energy prices by lowering the costs of environmental compliance, or potentially obviating or delaying the need for investments in transmission and distribution. These categories of benefits have not been quantified because the economic methodologies involved are not as well developed or standardized. Therefore, the total customer benefits of AMI could be substantially larger than the limited set of benefits reported in this Business Case.

Additional Benefits

Customer Benefits

ACE utilizes a market research model developed by Market Strategies, Inc. ("MSI") to assist the company in identifying the key drivers of customer satisfaction. The energy delivery benefits associated with AMI related to billing, customer service, energy information and reliability contribute positively to ACE's customer satisfaction performance once the full Blueprint plan is implemented. Additional customer benefits include:

- Improved website capabilities which will provide interval usage data to enable customers to understand when and how they are consuming energy at their homes and businesses.

- Individual customer load profile data can be useful in enabling the utility to target specific conservation programs or messaging to those customers who would achieve the maximum benefit. ACE's "My Account" software has the capability to provide "Energy Grams" to customers which would offer customized energy conservation information based on how they are currently using energy.

- AMI would enable ACE to provide for a "point of purchase" notification or understanding by consumers. ACE's "My Account" software has the capability of providing AMI metered customers with "My bill to date" which enables customers to see how much they have spent so far in any given month. The "My bill to date" feature also enables the utility to perform outbound notifications to customers letting them know when energy consumption or spending has reached customer prescribed levels. These notifications will raise awareness of energy use and contribute to changing consumer behavior towards conservation and environmental stewardship.

- AMI allows ACE to potentially offer "On-Request" meter reading services whereby a customer could request a specific meter reading which would show consumption information for a period of time (1 hour for example). This type of reading would let customers see a "before and after" view of energy use which enables them to see the benefits of conservation.

- AMI will enable ACE to provide on-line assistance with rate evaluations. Customers would benefit from having an Interactive Rate Comparison program available on line to examine the cost savings potential of various rate options in a manner that is customized based on their actual historic load profile. Users would select among options and calculate the energy costs for each option automatically. Users could then print out a summary of the analysis to be used for making rate decisions.

- AMI provides improved customer service due to the ability to remotely verify or determine that a particular meter is currently in service or out of service. This helps to alert the customer that the problem may be on the customer side of the meter.

- With AMI, it would be possible to offer customers an option of changing their monthly billing due date. This could conceivably provide some cash flow and payment flexibility benefit for customers.

- AMI information will benefit our Customer Contact Centers by enabling Customer Service Representatives ("CSR's") to quickly identify the time of high customer usage. This would enable the CSR to offer enhanced levels of customer educations by explaining exactly when periods of high usage are occurring at the customer's home or business.

- AMI allows the Company to be less intrusive to customers by not having meter reading personnel in or near the customer's home or business.

Theft of Service

The Company expects to improve the detection of lost revenue due to energy theft and other metering issues and to ultimately reduce it by using the capabilities of the AMI system. The AMI system is expected to enhance the Company's ability to identify and recover lost revenue in three ways. First, by visiting all of the Company's meter locations during the initial AMI meter deployment, we anticipate that some percentage of the meters currently affected by tampering, diversion or other problem will be found and remedied. Second, once the AMI system is installed, the Company anticipates that additional data will be available to indicate the status of the meter as well as provide electronic notification of possible tampering. This functionality will permit more timely identification, investigation and remediation of possible theft events. Finally, by using the interval data from the AMI system coupled with the analytical capabilities provided by the MDMS, the Company expects to develop the capability to analyze usage and other patterns to discern possible theft cases, particularly with commercial accounts. According to the Edison Electric Institute ("EEI"), electric utilities typically estimate approximately one to three percent of their annual revenue is lost due to energy theft. If the expected AMI capabilities enable the Company to improve its energy theft recovery by 0.5% of its annual kilowatt hour sales, we estimate that the recovered volume would be about 55 million kilowatt hours or about $7.7 million per year, assuming a combined residential distribution and standard offer service rate of 14.05 cents per kilowatt hour. Customers might experience a small reduction in rates due to reduced losses from the electrical system as the costs of the diverted electricity are paid for by the actual responsible parties. This benefit, however, would represent a shift in cost responsibility among customers, rather than a reduction in total revenue requirement recovered from all customers and was not included in this analysis.

Costs to Deploy

This section of the report provides the initial cost estimates for the deployment of the AMI system and the associated meter data management system. The costs will change as the Company conducts the procurement phase of its AMI project and evaluates the capabilities of the various AMI systems available in the market today. In addition, the quantifications will also change due to changing labor rates, payroll loading rates, inflation and other possible changes in the underlying assumptions used to derive the estimated cost values. Below is Figure 9 summarizing total capital expenditures needed for the initial deployment of the AMI system and annualized O&M costs expected in the first full year after deployment, followed by a more detailed description of each cost category.

Figure 9

Line	AMI System Components	Initial Deployment Costs Only, $ in 000s New Jersey	
1	Meters, including Installation Cost	$	80,471
2	Communications Network, including Installation Cost	$	39,323
3	AMI Network Management System and Meter Data Management System	$	7,881
4	Contingency	$	1,021
	Total Capital Expenditures	$	128,696
	AMI System Incremental Cost to Operate	**Annual Estimated Costs After Deployment, $ in 000s New Jersey**	
5	MDMS Software Maintenance & License Fees	$	110
6	MDMS Hardware Leasing	$	300
7	AMI Network Management System O&M	$	355
8	Communications Network Infrastructure O&M	$	452
	Total Incremental Cost to Operate	$	1,217

Note that the costs in the figure above exclude certain one time costs described in number 9 below.

1) Meters and Installation Labor

Costs include new AMI meters (540,000 meters) that contain certain equipment "under glass" such as a remote connect/disconnect switch for certain meters, communications modules where applicable and the associated installation labor. Prices for AMI equipment are estimated using filings from other utilities as well as initial quotes from a few vendors and the calculated estimates consider differences in commercial and residential equipment requirements. A value of $85.00 is used for the AMI base cost for residential electric meters and a $173.00 value is used for commercial electric meters. Additionally 99% of residential electric meters will require a $25.00 remote connect/disconnect switch, which is not required for the commercial electric meter. Labor cost for installations/ retrofits is estimated at $16.50 per electric meter. This brings the estimated cost for meters with the associated installation labor to about $80 million.

2) Communications Network Infrastructure and Installation Labor

The communications network infrastructure solution is assumed to leverage the Company's existing network. The cost of this component of the AMI system is more variable than the other components (i.e., meters and the network management IT system), given the different ways AMI vendors configure and price their communications networks combined with the variability of terrain, meter density and meter locations in New Jersey. For purposes of this cost estimate, $70.00 per electric meter, including installation costs, was used. The total estimated costs for communications network infrastructure and the associated installation is about $39 million.

3) AMI Network Management System and Meter Data Management System

This cost category captures the estimated costs associated with software applications, systems integration and computer hardware necessary to support AMI. System costs include categories for

- MDMS – software license, servers, storage, operating system, database management system, clustering software, and system design, configuration and integration

- Customer Presentment – servers, storage, and system design, configuration and integration

- PHI Integration – CIS and other IT systems integration.

The total estimated costs for the AMI Network Management System and the Meter Data Management System are about $8 million.

4) Contingency

We determined that a contingency should be applied to the start-up and installation activities as a way to help manage the current uncertainty around the AMI cost estimate. A contingency amount comprising 1% of the capital investment for Atlantic City Electric, representing an amount of about $1 million is included to cover unexpected increases in equipment costs, labor costs or materials prices.

5 and 6) MDMS Software Maintenance, License Fees and Hardware Leasing

The MDMS will require software maintenance and license fee contracts with the system's vendor for system support, upgrades and the like. The operating costs for the hardware for the MDMS system include the hardware leasing costs for the servers, the data warehouse system and data storage capacity.

7) AMI Network Management IT System O&M

The AMI Network Management IT System has costs similar in nature to the MDMS with regard to software and hardware. Three additional FTEs are estimated to be required after AMI deployment to operate and maintain the AMI system for PHI.

8) Communication Network Infrastructure O&M

These costs include the estimated ongoing maintenance of the communications equipment needed to transmit the data back and forth between the meters on the customers' premises and the Company's offices. This cost is dependent on the mix of communication technologies ACE ultimately obtains through its procurement process.

9) Labor Related Costs

The reduction in certain types of work would be phased in after the 2012 deployment, with labor related costs being incurred over a two year period (2011 and 2012). These costs would include reassignment and retraining of employees. The estimated cost of this one time expense is $0.4 million.

Accelerated Depreciation

As stated in the 2007 NARUC[3] Resolution to Remove Barriers to the Broad Implementation of Advanced Metering Infrastructure, the deployment of AMI technology will require the removal and disposition of existing meters that are not fully depreciated and the replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure. To encourage the implementation of this new technology the Commission should adopt ratemaking policies that remove a utility's disincentive toward demand-side resources that reduce throughput; provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and provide depreciation lives for AMI that take into account the speed and nature of change in metering technology.

The business case reflects depreciation lives for AMI that take into the account the speed and nature of the change in metering technology. The business case reflects a recovery period of fifteen years for the AMI investment and five years for the recovery of the remaining costs associated with the existing metering system. As of December 31, 2006, the Company's existing electric metering system had a remaining net book value of about $42 million. Depreciation calculations in the business case may need to be updated due to pending federal legislation.

[redacted]

[3] See NARUC Resolution Attached in Appendix 2

Appendix 1

Developments in other jurisdictions

Congress with the passage of the Energy Policy Act of 2005 recognized the importance of advanced metering for growth in the development of electric demand response programs across the United States. To advance the development of such programs, Congress directed the Federal Energy Regulatory Commission ("FERC") to assess demand response resources currently in existence in the electric power industry. FERC conducted a survey where they requested information from every state on the number and uses of advanced metering, existing demand response and time-based rate programs within their state. As a result of this survey, states were required to consider the adoption of a smart metering standard for each of their state regulated utilities.

Many states took the FERC survey results and determined methods for confronting the rising energy costs within their particular states with Advanced Metering Infrastructure and Demand Response Programs. The following identifies several utilities which have obtained approval from their individual state regulatory commissions and are beginning implementation of intelligent meter technology, demand response and time-based rate programs within their operating jurisdictions. California and Texas utility companies have led the way in implementation of AMI and Demand Response Programs.

CALIFORNIA

The California Public Utilities Commission ("CPUC") in 2004, directed each of the state's regulated utilities to explore the option and feasibility of upgrading their home and small-business electric meters to digital intelligent meters, similar to the types used to measure energy usage by larger commercial customers. The CPUC's goal was for its state regulated utilities to significantly ease California's constrained energy resources by providing some form of demand response during periods of peak demand. The need for a smart metering standard was essential in California due to the increased growth in population and per-person energy use in the state. California's state energy policies require utilities to commit large amounts of resources to fund and implement energy efficiency programs.

Pacific Gas & Electric ("PG&E")

Pacific Gas & Electric in 2006 obtained approval from the CPUC for the universal deployment of an AMI system which required the installation of 5.2 million electric meters and 4.1 million gas meters throughout its operating territory. PG&E immediately began an AMI pilot program in Bakersfield, California to test the accuracy and performance of SmartMeter™ after winning approval from the CPUC. Mass deployment of PG&E's SmartMeter™ Program is expected to begin in late 2007.

Southern California Edison ("SCE")

Southern California Edison obtained approval from the CPUC to replace its existing 5.1 million electric meters with "next generation" electronic intelligent meter technology beginning in 2009. Edison SmartConnect™ is Southern California Edison's AMI Program which aims to improve overall customer service by allowing customers to proactively manage their energy use and also save money through participation in programs with time-differentiated rates and demand response options. The Edison SmartConnect™ program is the first overhaul of SCE's metering system since 1949.

San Diego Gas & Electric ("SDG&E")

San Diego Gas & Electric obtained approval from the CPUC in April 2007 to begin implementation of "smart meter" technology for its estimated 1.4 million electric meters and retrofitting approximately 900,000 gas meters throughout its service territory beginning in 2008. SDG&E's approval also includes an agreement with the CPUC's Division of Ratepayer Advocates ("DRA") and the Utility Consumers' Action Network ("UCAN") to become a leader in emerging energy technologies through the use of a smarter electric distribution grid.

TEXAS

With the passage of House Bill 2129, the Texas Public Utility Commission was required to study the benefit to be derived by electric utilities in Texas from advanced metering. Because of the retail choice environment of the Texas retail market, the challenge exists for implementing advanced metering in a way that will maximize the benefits for the utility company, retail providers and customers. The Texas Commission has also initiated a separate project to evaluate potential demand response programs for the Texas utilities market.

Centerpoint Energy

Centerpoint obtained approval from the Texas Public Utility Commission in 2006 for implementation of smart meter technology for its more than three million electric and natural gas customers in the Houston area. Implementation of smart electricity meters began in November 2006 in selected areas of Houston.

TXU Electric Delivery

TXU Electric Delivery plans to have its 3 million automated meters by 2011, complementing an advanced grid intelligent enough to monitor electric service real-time. By year's end, TXU Electric Delivery expects to have 370,000 automated meters system-wide, including 10,000 BPL-enabled meters. The BPL-enabled network will serve approximately 2 million residential and commercial customers in Texas.

OTHER JURISDICTIONS

Several utility companies in other jurisdictions have either filed applications or have obtained approval for implementing advanced metering and demand response programs. A sampling of these utilities companies are outlined below.

- *Detroit Edison* ("DTE") – The Michigan Commission approved DTE's plan to replace 3 million electric meters. DTE is investing $330 million for implementation of this over the next six years. DTE has also created a Home Energy Saver audit tool on their website (mydteenergy.com) to help customers manage their energy use and obtain conservation tips.

- *Pennsylvania Power & Light Company* ("PPL") – PPL completed the installation of 1.3 million electric meters in 2004. PPL has created sections on its website dedicated to energy conservation efforts, including an energy calculator, detailed information about smart meters, safety concerns and an energy library for customers to learn more about energy usage in their homes.

- *Baltimore Gas & Electric Company* ("BGE") – BGE filed for approval by the Maryland Public Service Commission in early 2007 of its plan to deploy an AMI system and Demand Side Management Programs.

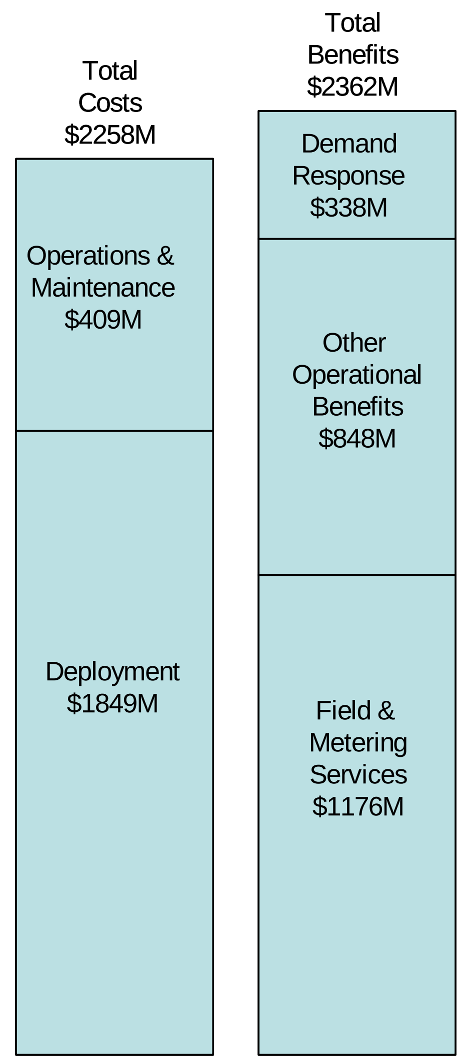
- *Southern Company* – Southern Company obtained Commission approval to replace 4.5 million electric meters in their four-state operating territory.

- *Portland General Electric* ("PGE") – PGE has filed an application with the Public Utility Commission of Oregon to install 843,000 smart meters for both residential and small non-residential customers throughout PGE's operating territory.

Business Case Summaries from Other Utilities

Summaries based on publicly available information from filings for PG&E Southern California Edison and San Diego Gas and Electric are included below. The summaries demonstrate the similarities in approach and results with PHI's AMI business case analysis.

Pacific Gas and Electric Company



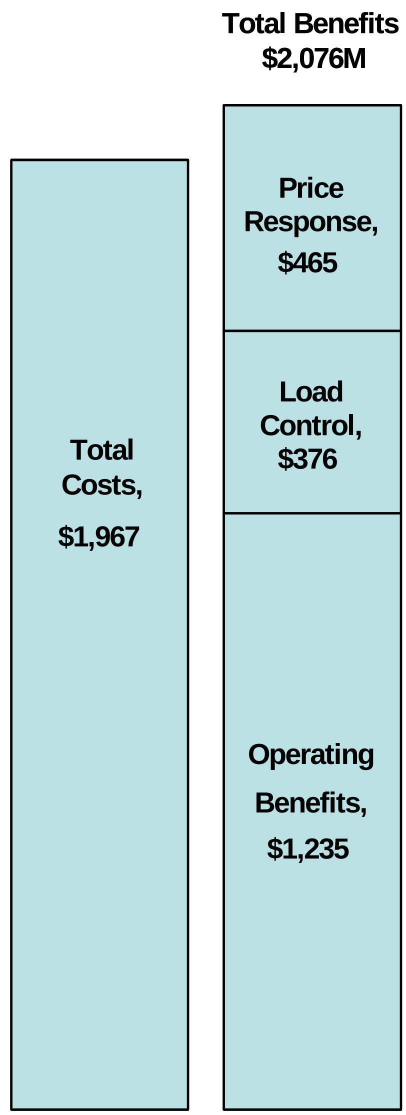
The AMI business case filed by PG&E with the California Public Utilities Commission shows that AMI can largely be justified by the operational benefits and savings to the utility. The operational "gap" between the costs and benefits for a full AMI deployment case is $234 million on a present value revenue requirement ("PVRR") basis. Adopting a benefit calculation* for Demand Response of $338 million which is more conservative than a Base Case* of $510 million still results in finding that the project is cost-effective.

The field and metering services benefits include the reduction/elimination of the labor and non-labor costs required for regular meter reading and change of party/special reads and remote Turn-On/Shut-Off. Other operational benefits include improvement in Electric & Gas Transmission and Distribution restoration after significant outages, reduced customer calls and duration of calls related to billing and power outages, and reduced employee-related costs.

The major categories of deployment costs for AMI include meter and module equipment and installation costs, network equipment and install costs, and IT costs that include interval billing system, interface and integration costs. Operational and maintenance costs include AMI operation costs, meter operation costs, marketing and communications costs, and customer acquisition costs

Southern California Edison

The AMI business case filed by SCE with the California Public Utilities Commission shows that AMI is justified by the Operational, Load Control, and Price Response Benefits to the utility. The operational "gap" between the costs and benefits for a full AMI deployment case is $356 million on a present value revenue requirement basis. The new functionality of the Edison SmartConnect™ technology not only increases the ways in which customers can use demand response; it also results in SCE going from a negative $951 million Present Value Revenue Requirement in 2005,* to a positive $109 million PVRR in 2007 for full AMI deployment.



Through its AMI System Design and Use Case Process, SCE will integrate Edison SmartConnect™ into its operating systems to ensure that the expected benefits accrue in the areas of customer service, billing, outage management, and operations and maintenance.

Operational savings are forecast to cover approximately 63 percent of the related costs. Participation by residential and <200kW business customers in dynamic pricing and demand response programs is expected to provide sufficient additional benefits to justify the Edison SmartConnect™ project. The cost-benefit analysis is summarized in the Figure below.

* Source: EDISON SMARTCONNECT™ DEPLOYMENT

FUNDING AND COST RECOVERY

Volume 1 –Policy July 31, 2007 - Before the Public Utilities Commission of the State of California

[redacted]

Appendix 2 NARUC Resolution

Resolution to Remove Regulatory Barriers To the Broad Implementation of Advanced Metering Infrastructure

WHEREAS, The Energy Policy Act of 2005 amended the State ratemaking provisions of the Public Utilities Regulatory Policies Act of 1978 (PURPA) to require every State regulatory commission to consider and determine whether to adopt a new standard with regard to advanced metering infrastructure (AMI); *and*

WHEREAS, Advanced metering, as defined by Federal Energy Regulatory Commission (FERC), refers to a metering system that records customer consumption hourly or more frequently and that provides daily or more frequent transmittal of measurements over a communication network to a central collection point; *and*

WHEREAS, The implementation of dynamic pricing, which is facilitated by AMI, can afford consumers the opportunity to better manage their energy consumption and electricity costs through the practice of demand response strategies; *and*

WHEREAS, Effective price-responsive demand requires not only deployment of AMI to a material portion of a utility's load, but also implementation of dynamic price structures that reveal to consumers the value of controlling their consumption at specific times; *and*

WHEREAS, AMI deployment offers numerous potential benefits to consumers, both participants and non-participants, including:

- greater customer control over consumption and electric bills;
- improved metering accuracy and customer service;
- potential for reduced prices during peak periods for all consumers;
- reduced price volatility;
- reduced outage duration; and,
- expedited service initiation and restoration; *and*

WHEREAS, The use of AMI may afford significant utility operational cost savings and other benefits, including:

- automation of meter reading;
- outage detection;
- remote connection/disconnection;
- reduced energy theft;
- improved outage restoration;
- improved load research;
- more optimal transformer sizing;
- reduced demand during times of system stress;
- decreased T&D system congestion; and,
- reduced reliance on inefficient peaking generators; *and*

WHEREAS, Sound AMI planning and deployment requires the identification and consideration of tangible and intangible costs and benefits to a utility system and its customers; *and*

WHEREAS, Cost-effective AMI may be a critical component of the intelligent grid of the future that will provide many benefits to utilities and consumers; *and*

WHEREAS, It is important that AMI allow the free and unimpeded flow and exchange of data and communications to empower the greatest range of technology and customer options to be deployed; *and*

WHEREAS, The deployment of cost-effective AMI technology may require the removal and disposition of existing meters that are not fully depreciated and may require replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure; *and*

WHEREAS, Regulated utilities may be discouraged from pursuing demand response opportunities by the prospect of diminished sales and revenues; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its February 2007 Winter Meetings in Washington, D.C., recommends that commissions seeking to facilitate deployment of cost-effective AMI technologies consider the following regulatory options:

- pursue an AMI business case analysis, in conjunction with each regulated utility, in order to identify an optimal, cost-effective strategy for deployment of AMI that takes into account both tangible and intangible benefits;
- adopt ratemaking policies that provide utilities with appropriate incentives for reliance upon demand-side resources;
- provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and,
- provide depreciation lives for AMI that take into account the speed and nature of change in metering technology; *and be it further*

RESOLVED, That the Federal tax code with regard to depreciable lives for AMI investments should be amended to reflect the speed and nature of change in metering technology; *and be it further*

RESOLVED, That NARUC supports movement toward an appropriate level of open architecture and interoperability of AMI to enable cost-effective investments, avoid obsolescence, and increase innovations in technology products.

Sponsored by the Committee on Energy Resources and Environment
Adopted by NARUC Board of Directors February 21, 2007

EXHIBIT
C

Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs

Prepared by

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44 Brattle Street
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Prepared for

Pepco Holdings, Inc.

September 21, 2007

1.0 EXECUTIVE SUMMARY

The Brattle Group has been retained by Pepco Holdings, Inc. (PHI) to estimate customer benefits from reductions in peak loads during critical times that are likely to be achieved by PHI's proposed demand-side management (DSM) initiatives in all of its Delaware, District of Columbia, Maryland and New Jersey jurisdictions.[1] This whitepaper describes the methodology and conclusions from *Brattle*'s analysis, which involves two major components: first, determining the magnitude of load reductions that are likely to be achieved by PHI's proposed DSM initiatives, as outlined in its *Blueprint for the Future*;[2] and second, estimating the customer value of such load reductions. PHI's *Blueprint* proposes programs in energy efficiency and direct load control, and announces its planned deployment of an advanced metering infrastructure (AMI), which will enable direct load control and dynamic pricing. This study estimates the customer benefits from peak load reductions resulting from all of these measures, which are collectively referred to in this report as "DSM."

Reductions in critical peak loads (top 60 hours) are estimated as follows: load reductions from energy efficiency and direct load control are provided by PHI, consistent with the *Blueprints*. (The sub-components of the energy efficiency and direct load control programs are shown in Figure A.1 in the Appendix.) Load reductions associated with AMI-enabled dynamic pricing programs are estimated using the Pricing Impact Simulation Model (PRISM) model, which is based on empirical data from the California Statewide Pricing Pilot and is calibrated to the load, rate, air conditioning and weather characteristics of residential and small commercial and industrial (C&I) customers in each of PHI's jurisdictions.

Two alternative dynamic pricing scenarios are analyzed, both based on the dynamic rates designed for the District of Columbia smart metering pilot program.[3]. In one scenario, customers can voluntarily elect to enroll in a CPP rate structure, resulting in 20 percent of eligible customers participating.[4] In the alternative scenario, CPP is the default (but not mandatory) rate structure, resulting in 80 percent of eligible customers participating. As shown in Figure 1.1, the combined peak load reductions from all of PHI's proposed DSM programs would likely be quite substantial when full deployment of AMI is reached by 2013.

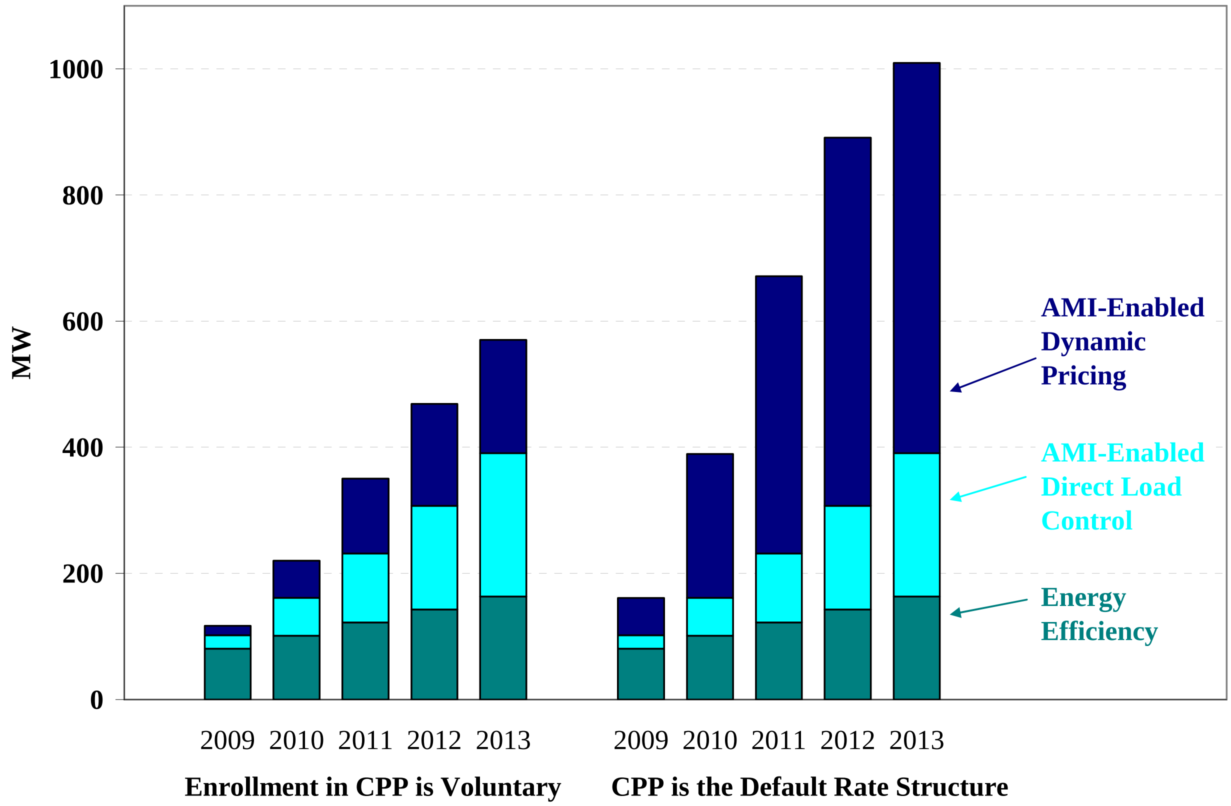
[1] PHI is selling its Virginia electric distribution service territory.

[2] Delaware Public Service Commission, Docket # 07-28, filed on February 6, 2007; Maryland Public Service Commission ML#106885 filed on July 23, 2007.

[3] PowerCentsDC is the smart metering pilot program in the District of Columbia managed by the Smart Meter Pilot Program, Inc. (SMPPI). Board members of SMPPI include representatives of Pepco, the District of Columbia Office of People's Council, the District of Columbia Commission, the District of Columbia Consumers Utility Board, and the International Brotherhood of Electrical Workers. The pilot is testing three alternative dynamic electricity rates: Critical Peak Pricing, Hourly Pricing, and Critical Peak Rebate. Pricing adjustments are made based upon day ahead PJM sub Zonal PJM hourly market prices.

[4] Eligible customers are assumed to include all residential and small commercial industrial customers that do not already have an interval meter. AMI is expected to provide hourly load data to the utility on a daily basis.

Figure 1.1. Estimated Peak Load Reductions from PHI's Proposed DSM Programs (MW)

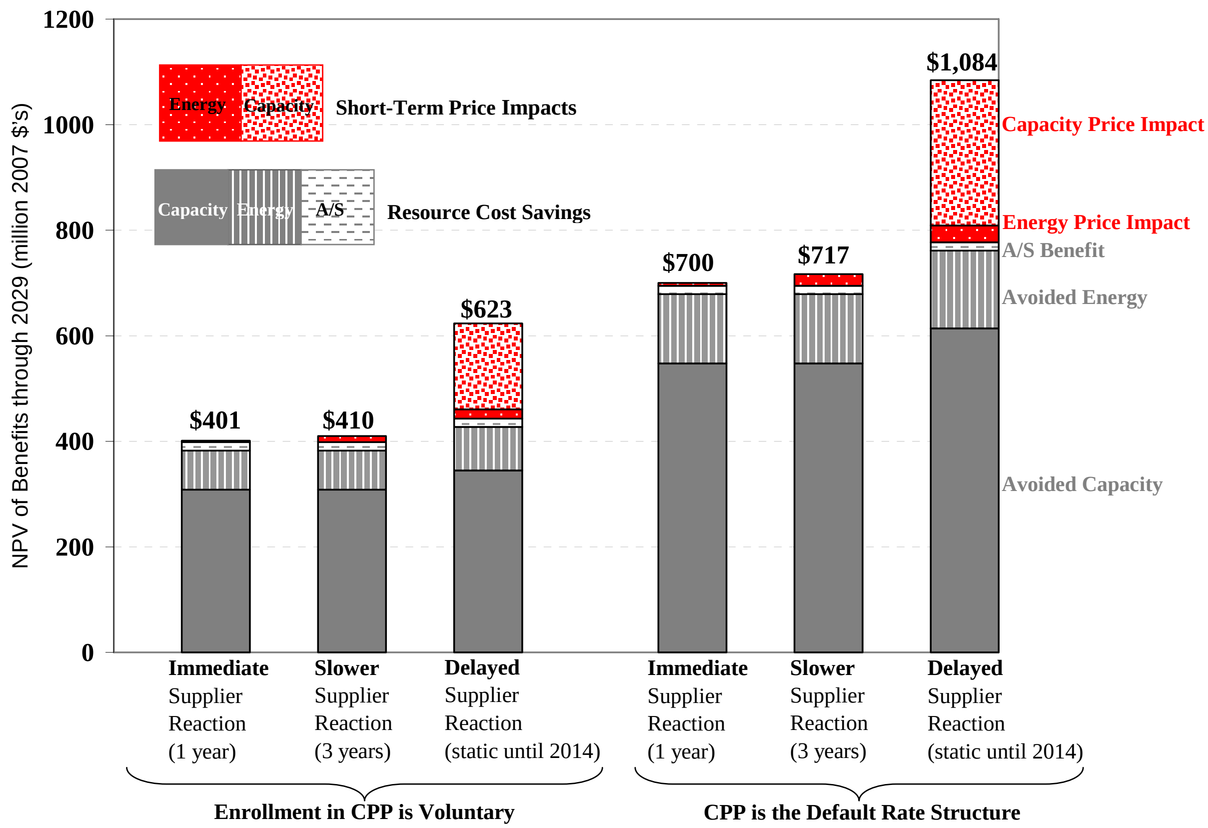


Reducing peak load benefits customers in several ways, including: (1) providing "resource cost savings" by reducing the quantity of capacity, energy, and ancillary services that customers must buy (or enabling them to sell those products); (2) creating "short-term market price impacts," *i.e.*, depressing wholesale market prices for energy and capacity; (3) improving reliability; (4) enhancing market competitiveness; (5) reducing rate volatility; (6) reducing transmission distribution losses; and (7) potentially obviating or delaying the need for investments in transmission and distribution.

This analysis estimates the customer savings that PHI's proposed DSM programs are likely to achieve by lowering resource costs and, separately, by temporarily reducing market prices. The applied methodology is consistent with *The Brattle Group*'s January, 2007 study, *Quantifying Demand Response Benefits in PJM*, sponsored by PJM the Mid-Atlantic Distributed Resources Initiative (MADRI), and the public utility commissions in Delaware, The District of Columbia, Maryland, New Jersey, and Pennsylvania. However, the present study includes several enhancements, most notably the estimation of capacity price impacts and a scenario analysis addressing the longevity of "short-term price impacts." The other categories of benefits (numbers 3-7 listed above) are discussed qualitatively but have not been quantified because the economic methodologies involved are not as well developed or standardized, nor could they be analyzed within the scope of this analysis. The study scope also excludes changes in consumption during the non-critical-peak hours because the energy price effects during those hours are less pronounced and capacity effects are non-existent, even if the impact on total generation and emissions are significant (e.g., due to improved equipment efficiencies or improved energy management based on AMI-enabled information regarding customers' energy usage patterns). Therefore, the total benefits of PHI's proposed programs could be substantially larger than the benefit estimates reported here.

A key insight affecting the design of this study is that resource cost savings persist over time, but market price impacts can be expected to diminish as generation suppliers respond to depressed prices, for example, by delaying their construction of new generation or accelerating their retirement of existing plants. The magnitude and duration of the market price impact depends on the rate at which suppliers respond to changes in market conditions as well as on the tightness of the market over the next several years. Accordingly, this study quantifies customer benefits under a range of supply scenarios. Figure 1.2 shows the net present value of benefits to customers in all of PHI's load zones (including municipal and cooperative utilities contained within the PHI load zones) if energy efficiency, direct load control, and dynamic pricing were implemented in all of PHI's jurisdictions. The net present value assesses benefits, and not costs, through 2029, based on a 15-20 year life of equipment and programs, discounted at a rate equal to the after-tax weighted average cost of capital filed by PHI utilities.

Figure 1.2. Net Present Value of Quantified Customer Benefits in all PHI Zones through 2029 (Millions of 2007 Dollars)



The following insights can be drawn from this analysis:

- Overall, avoided capacity and energy benefits (*i.e.* buying less quantity) dominate the Net Present Value (NPV) in every scenario because of the longevity of these benefits relative to short-term price impacts.
- Customer benefits are greatest if dynamic pricing is the default rate structure.
- Customer benefits would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of DSM, but they would be much greater in a scarcity situation in which generation supply is static until 2014 (except for projects already in PJM's queue). If such scarcity were realized, having AMI in place would enable the Commission to substantially mitigate customer costs by making dynamic pricing the default rate structure.
- Short-term savings to all customers, including those outside of PHI's zones, would be much larger because PHI's load reductions would have a PJM market-wide impact on energy and capacity prices. For example, the total benefits to all of PJM-East are five to eight times greater than the benefits to all customers in the PHI zones. (The PHI zones contain approximately 20 percent of the load in PJM-East.)
- The customer savings to PHI customers would be nearly twice as large as if all utilities in PJM-East followed PHI's lead in deploying DSM programs and achieved similar load reductions. The aggregate load reductions would create a much greater, market-wide short-term price impact.
- Although CPP programs typically designate peak periods on a day-ahead basis, making the programs callable on a real-time basis (instead of a day-ahead time frame) would enable customers to mitigate the impacts of real-time surprises in load or supply outages. This could add an additional $2 to $10 million in value, depending on the scenario.[5]
- Although this analysis does not quantify the reliability benefit in financial terms, DSM's potential contribution to installed reserve margins has been estimated. In the scenario in which CPP is the default rate structure and suppliers build no new capacity until 2014 (other than projects in advanced stages currently in the PJM Generation Queue), PHI's DSM programs would increase reserve margins in Southwestern MAAC from 15.2 percent to 18.3 percent in 2010, and from 5.8 percent to 14.4 percent in 2013; in Eastern MAAC from 18.1 percent to 21 percent in 2010 and from 11.5 percent to 19.9 percent in 2013. Thus, PHI's DSM initiatives would provide substantial value as insurance against intolerably low reserve margins.

[5] Day-of CPP programs were tested in the California pilot and were found to be feasible. In addition, Illinois has tested real-time pricing for residential customers and shown it be feasible and attractive to customers.

These estimates of customer benefits are likely to be conservative due to the limited scope of benefits quantified. Furthermore, the largest component of the estimated benefit, the avoided capacity costs, is probably understated because it is based on a historical Net Cost of New Entry that does not account for the recent dramatic worldwide upswing in the cost of all kinds of new generation. On the less conservative side, it is possible that the Inadequate Supply Response scenario exaggerates the looming supply shortage in Southwest and Eastern MAAC by assuming zero entry of capacity that is not yet planned until 2014.[6] The scenario was constructed to demonstrate the potential value of DSM in a severely supply-constrained situation.

[6] It could be argued that even if private investors under-provide new capacity in that time period, they will still add some capacity, and the utilities could also build new capacity as a last resort.

2.0 ORGANIZATION OF THIS REPORT

Section 3 presents an overview of the study design, economic concepts, and analytical methodologies employed. Section 4 describes the assumptions, data, and methodology used to estimate peak load reductions from dynamic pricing (there is no similar discussion of the peak load reductions from energy efficiency and direct load control because those figures were provided directly by PHI and detailed in the Company's various *Blueprint for the Future* filings). Sections 5 through 7 provide a detailed explanation of the analysis of customer benefits from all of PHI's proposed DSM programs: Section 5 addresses resource cost savings; Sections 6 and 7 address short-term energy and capacity price impacts, respectively. Section 8 discusses customer benefits that have not been quantified in this study.

Whereas the executive summary presents only the benefits to customers in PHI zones when all of PHI's DSM initiatives are implemented, Section 9 provides the benefits to the rest of the customers in each of the states, and also the potential benefits if all utilities in PJM-East followed PHI's lead and deployed programs achieving load reductions similar to those in PHI.

3.0 OVERVIEW OF METHODOLOGY

The analysis of benefits from PHI's proposed DSM initiatives involves two major components: first, determining the magnitude of likely peak load reductions; and second, estimating the value of such load reductions over time and under a range of market conditions.

3.1. STUDY DESIGN

Analyzing DSM benefits in multiple jurisdictions over time and over a range of plausible future market conditions required several study design choices regarding time, scenario definition, and the assumed scope of DSM implementation and benefits.

3.1.1. Scope of DSM Implementation and Benefits

Benefits are estimated for all customers in each PHI zone (separated by state where applicable), each state (all zones), and the entire PJM-East region, under three alternative assumptions regarding the scope of DSM implementation: in each PHI zone in isolation, in all PHI zones simultaneously, and in the entire PJM-East region. The body of this report focuses on the benefits to customers in the PHI zones resulting from PHI-wide implementation, Section 9 shows all combinations of implementation and beneficiary areas.

3.1.2. Time

The analysis of benefits focuses on critical peak hours in the summers of 2010 and 2013 then interpolates and extrapolates to 2009-2029 based on the relative amounts of peak load reductions expected in each year. Market price benefits are assumed to diminish over time as suppliers delay new construction and accelerate retirements in response to reduced load and market prices (according to the three supplier response scenarios discussed below). The multi-year stream of benefits is translated into a net present value using the after-tax weighted average cost of capital for each of the PHI jurisdictions.[7]

3.1.3. Scenario Definition

Scenarios were designed to span the range of plausible future market conditions. Scenarios differ in the factors that most affect the value of DSM: customer participation rates in the DSM programs and the activity of suppliers.

Customer Participation. Customer participation rates depend primarily on whether CPP becomes the default rate structure or merely an optional tariff. In the "CPP Default Rate Structure" scenario, 100 percent of customers would be enrolled initially and some 20 percent would eventually switch to a non-CPP rate structure, leaving 80 percent participation in year two and beyond. In the "CPP-Optional" scenario, no customers would sign up initially, ramping up to 20 percent in two years and beyond. These rates are based on the experience from the California Statewide Pricing Pilot and other pilots.

Supplier Responsiveness. The energy/capacity price impacts of DSM are larger and longer lasting in a scarcity situation than a surplus market or a balanced market in which suppliers react quickly to DSM's successes (and price impacts) by delaying construction of new capacity or by accelerating the retirement of existing plants. A range of possible market conditions is explored using three supplier scenarios in which the longevity of price impacts is varied:

- In the "Immediate Supplier Reaction" scenario, the market is in supply-demand equilibrium, and suppliers react quickly to changes in fundamentals. Short-term energy price impacts (which are derived from the *Brattle*-PJM-MADRI study, which used a short-term equilibrium model in which supply was static), lasts for only one year before suppliers fully react. One year after the introduction of new DR, suppliers have accelerated enough retirements and/or delayed enough new construction to completely offset the price impact of DR. Hence, if PHI's deployment schedule produces 200 MW of peak load reduction in year n and 300 MW in year $n+1$, only 100 MW of load reductions has a price impact in year $n+1$. This scenario is consistent with the observation that suppliers in the recent Reliability Pricing Model (RPM) Base Residual Auction quickly changed their plans by delaying retirements presumably in response to high Eastern prices in the prior auction.[8]
- The "Slower Supplier Reaction" scenario is similar to the Immediate scenario except that short-term price impacts last for three-years before

[7] The same utility discount rates were used as in PHI's AMI Business Case Reports for each PHI jurisdiction. These rates are stated in Section 9 of this report.
[8] See "2008/ 2009 RPM Base Residual Auction Results," PJM Docs #428082, July, 2007.

suppliers respond. The three year response time is consistent with the lead time on new construction.[9]

- In the "Delayed Supplier Reaction" scenario, suppliers do not build any capacity that is not currently in PJM's queue until 2014. The market becomes very short on capacity, raising capacity prices. Moreover, suppliers do not react to the introduction of DR because they have no new capacity to delay, and the acceleration of retirements is unlikely in a scarcity situation. Hence, short-term price impacts last through 2013. This scenario reflects the possibility that suppliers are reluctant to build new generation in the current uncertain environment regarding re-regulation, fuel prices, climate change, siting difficulties, and the rapidly escalating costs of new plant.[10]

Combinations. Each permutation of customer participation sales and supplier reaction rates is considered for a total of six scenarios.

Other Market Conditions. Estimates of the benefits from energy market impacts and avoided generation are based on the *Brattle*-PJM-MADRI study, which analyzed six scenarios representing a broad range of weather and fuel price conditions: actual 2005 market conditions, a weather-normalized case, a high peak load case, a low peak load case, a high fuel price case, and a low fuel price case.[11] The variation in customer benefits associated with each of these cases is expressed as a range in the Appendix. In the summary tables within the body of this report, only the average of the Low Peak and High Peak benefits is presented. Such an average is somewhat higher than the benefits in the Normalized Load case because it captures the non-linear increase in prices (and price sensitivity to DR) as market conditions become tighter.

3.2. ESTIMATION OF LOAD REDUCTIONS OVER TIME

PHI is proposing DSM programs involving energy efficiency, direct load control, and AMI, which will enable dynamic pricing programs. In order to estimate likely load reductions from AMI-enabled dynamic pricing programs, *Brattle* used the PRISM model. PRISM is based on California's Statewide Pricing Pilot, but it has been calibrated to PHI's customer characteristics and likely rate structure (based on the District of Columbia smart meter pilot program) and PHI's planned AMI deployment schedule, as discussed in Section 4.

PHI provided *The Brattle Group* with its estimates of likely peak load reductions resulting from its proposed energy efficiency and direct load control programs. These estimates have been adopted as-is without validation or modification by *The Brattle Group*. PHI's estimated reductions from energy efficiency, conservation, direct load control, and demand response

[9] See FERC Order on Rehearing and Clarification and Accepting Compliance Filing, Docket No. ER05-1410-002, *et al.*, paragraph 90, issued on June 25, 2007.
[10] See, for example, "Constellation, PPL See Gold in Tight Markets," *Megawatt Daily*, September 6, 2007.
[11] Because of the way the loads were constructed, the weather-normalized case and all of the scenarios other than the actual 2005 scenario are representative of possible conditions for 2007 or 2008, not 2005.

(excluding dynamic pricing) are contained within the Company's *Blueprint for the Future* filings.

In combination, dynamic pricing, direct load control, and energy efficiency lower peak loads significantly, as shown in Figure 1.1. The combined load reduction is the starting point for the analysis of customer benefits, as described below.

3.3. ESTIMATION OF CUSTOMER BENEFITS

This study estimates two major categories of benefits: resource cost savings and, separately, short-term price impacts. (Other categories of benefits that have not been quantified are discussed in Section 8.0).

3.3.1. Resource Cost Savings (Buying Less Quantity)

With reduced peak loads, customers do not need to buy as much capacity; indeed less generation capacity must ultimately be built to serve a flatter load shape. Customers also do not need to buy as much energy during high-priced periods. Reducing the *quantity* of capacity and energy that must be produced saves money even if wholesale prices remain unchanged. This kind of savings is often considered a "resource cost savings" because the total cost to serve load is reduced. Customers save commensurately whether they are in a cost-of-service regulatory regime, or in a market-based regime, as in PHI's footprint. Assuming a competitive wholesale market, suppliers can be expected to offer capacity and generation based on their costs to serve and to pass changes in their costs onto customers. If the wholesale market is not fully competitive, it is likely that savings would be even greater because DR enhances market competitiveness, as explained in Section 8.

Capacity savings are estimated by multiplying the projected reduction in physical capacity requirements by the $/MW value of physical capacity. The reduction in physical capacity requirements is estimated by assuming that all expected DR could either supply capacity or reduce the load forecast, thus avoiding the need for physical capacity to the extent that the simultaneous peak load forecast is reduced (multiplied by 1 plus the reserve margin). The value of capacity is given by the capacity price, which must be forecasted. In the "Immediate Supplier Reaction" and "Slower Supplier Reaction" scenarios, it is assumed that the market reaches an economic equilibrium by 2009, with capacity prices set by the net cost of new entry (Net CONE) used by PJM in its RPM. Net CONE is $51/kW-yr in Eastern MAAC and $54.5/kW-yr in Southwestern MAAC. However, in the "Delayed Supplier Reaction" scenario, the market is assumed to be in a scarcity situation until 2014. Capacity prices are assumed to be set by Net CONE in 2014 forward. Before then, prices are higher than Net CONE, given by the intersection of projected supply and demand curves, as described in Section 5.

Reducing demand also reduces the amount of energy that must be generated and purchased by customers (during high-priced periods). The economic savings depends on the particular type of generation that is being avoided, which could come from a combination of new capacity not constructed and old capacity retired or not dispatched. The savings is also partially offset by the value that the consumer forgoes by not consuming as much power. Assessing the forgone value to the customer is difficult to assess and also depends on whether the customer shifts load to lower-priced periods. These issues were addressed in the *Brattle*-PJM-MADRI study, in which net generation savings amounted to an additional 12 to 36 percent on top of the capacity savings. The present study simply adopts these figures by scaling the net generation savings from the *Brattle*-PJM-MADRI study to the amount of load reduction.

Interruptible demand (e.g., that under direct load control) could also create value by providing ancillary services (A/S) – load reductions would have to be on call for 30-minute dispatch at short notice, much like generation resources providing A/S. However, A/S value is somewhat speculative because PJM's inclusion of demand response in its A/S markets is in its infancy. Demand response (DR) currently provides some A/S in PJM and ISO-NE, including smaller customers (< 5 MW) on an experimental basis in ISO-NE.[12] We assume conservatively that AMI could eventually enable 100 MW of spinning reserves from loads that can be curtailed for 30 minutes on a moment's notice through direct load control. The contribution of DR to spinning reserves would provide the retail provider and/or program participants with a source of revenue and would reduce the need for supply-side resources to provide spinning reserves, the marginal value of which is given by the market price for spinning reserves. Hence ancillary service value is estimated by multiplying a conservative quantity of spinning reserves by a historical average price of spinning reserves ($8.5/MWh during 2004-06) by the number of hours in a year.

3.3.2. Short-Term Market Price Impacts (Buying at Lower Prices)

Even a small reduction in demand during tight market conditions may lower the market price for energy. This lowers the price of energy for all customers, not just those curtailing load, and not just customers in the zone where DR is implemented, as shown in the *Brattle*-PJM-MADRI study. Similarly, reducing the peak demand lowers the demand for capacity, which can lower the market price for capacity, which affects all customers in the same locational delivery area (another positive externality) and more broadly throughout the PJM market.

Short-term energy price reductions are estimated by adapting the results of the *Brattle*-PJM-MADRI study to reflect the differences in load reductions expected from PHI's DSM programs. To the extent that PHI's load reductions differ from the load reductions simulated in the *Brattle*-PJM-MADRI study, price impacts are estimated using linear extrapolation (e.g., twice the MW of load reductions causes twice the price impact). This linear approach does not consider that the marginal price effect could diminish as load reductions increase; that effect could be quantified by performing new simulations tailored to PHI's programs. However, performing new simulations would have required substantially more time and resources, and the increased precision would have been only minimally helpful given the uncertainties in market conditions, participation rates in dynamic pricing, and the unknown agility with which generation suppliers

[12] ISO-NE's Demand-Response Reserve Pilot Program is discussed in section 6.3 of ISO-NE's *2007 Regional System Plan* (third draft) dated August 30, 2007.

will react to the introduction of PHI's DSM initiatives. These uncertainties are handled through scenarios, which policy makers can weigh against each other.

As in the *Brattle*-PJM-MADRI study, the customer benefit from reduced energy prices can be estimated by multiplying the expected price reduction by the quantity of load exposed to market prices.[13] However, the *Brattle*-PJM-MADRI study assumed that all non-curtailed load was exposed to market prices, whereas the present analysis assumes conservatively that only a fraction of load is exposed to market prices. The remainder is assumed to be covered by pre-existing contracts that were priced without anticipating the effects of newly-introduced DSM. It is assumed that in any given year, 50 percent of load-serving obligations are supplied by pre-existing wholesale contracts, and 50 percent are supplied by new contracts under the "Immediate Supplier Reaction" scenario.[14] In the "Slower Supplier Reaction" scenario 5/6th of the load is assumed to be affected. These assumptions result in discounted customer benefits relative to the *Brattle*-PJM-MADRI study – a 50 percent discount in the "Immediate Supplier Reaction" scenario and a 17 percent discount in the "Slower Supplier Reaction" scenario.

A second difference from the *Brattle*-PJM-MADRI study is the quantification of real-time DR benefits. The *Brattle*-PJM-MADRI study quantified benefits for only day-ahead DR and discussed qualitatively the potential additional value from DR that is dispatchable in real-time and thereby able to mitigate the effects of real-time surprises in supply and demand. In the present analysis, it is assumed that loads under direct load control are dispatchable in real time, and the corresponding premium is estimated using the ratio of historical super-peak RT prices to super-peak DA prices. As an alternative, benefits are also estimated under the assumption that dynamically-priced loads can be activated in near real-time by designating peak periods day-of rather than day-ahead.

A third difference is that the present analysis includes an estimate of the capacity price impact from DR, whereas the *Brattle*-PJM-MADRI study did not address capacity price impacts. DR's role in capacity markets has increased with the recent inception of PJM's RPM. RPM allows demand-side resources to sell capacity into capacity auctions on equal footing with supply-side resources as long as they are on direct load control (by the utility, competitive retail providers, curtailment service providers and dispatched by the RTO).[15] Load reductions that are not under direct load control, including dynamic pricing and energy efficiency, can not sell supply into capacity markets, but they would similarly impact capacity prices by reducing peak electricity demand and thereby the PJM load forecast and thus the administratively-determined demand curve for capacity.

Capacity price impacts are estimated as follows: in the "Immediate Supplier Reaction" and "Slower Supplier Reaction" scenarios it is assumed that there is no capacity price impact,

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[13] Benefits are partially offset approximately 15 percent by associated reductions in the value of FTRs, as described in the *Brattle*-PJM-MADRI study.

[14] This assumed turnover rate corresponds roughly to the contract lengths and schedules by which standard offer service is procured in D.C., Delaware, and Maryland and basic generation service is procured in New Jersey.

[15] See, for example, PJM's RPM Training Materials, Module D – Supply in RPM, http://www.pjm.com/markets/rpm/downloads/training/module-d.pdf

consistent with the scenario definition that the market is in an economic equilibrium with the expected 3-year forward capacity price set by Net CONE, irrespective of the level of load and load reductions expected. In the "Delayed Supplier Reaction" scenario, the market is in a scarcity situation, and high capacity prices are mitigated somewhat by reductions in peak load. Capacity price impacts are estimated by intersecting supply and demand curves for capacity in the Eastern MAAC and Southwestern MAAC Locational Delivery Areas (where all the PHI zones are located) both with and without DR. The demand curve is constructed using PJM's load forecast and the other parameters used to determine the administratively-determined demand curve. The supply curve is constructed by adding projected new supply (from the generation interconnection queue) to the supply curve available from the most recent capacity auction.

The final, and perhaps most important, enhancement to the *Brattle*-PJM-MADRI study is the scenario analysis discussed in Section 3.1.3. The various scenarios address the rate at which short-term price impacts are offset by suppliers' reactions to DSM.

4.0 FORECASTING PHI'S PEAK DEMAND REDUCTIONS DUE TO DYNAMIC PRICING

4.1. OVERVIEW

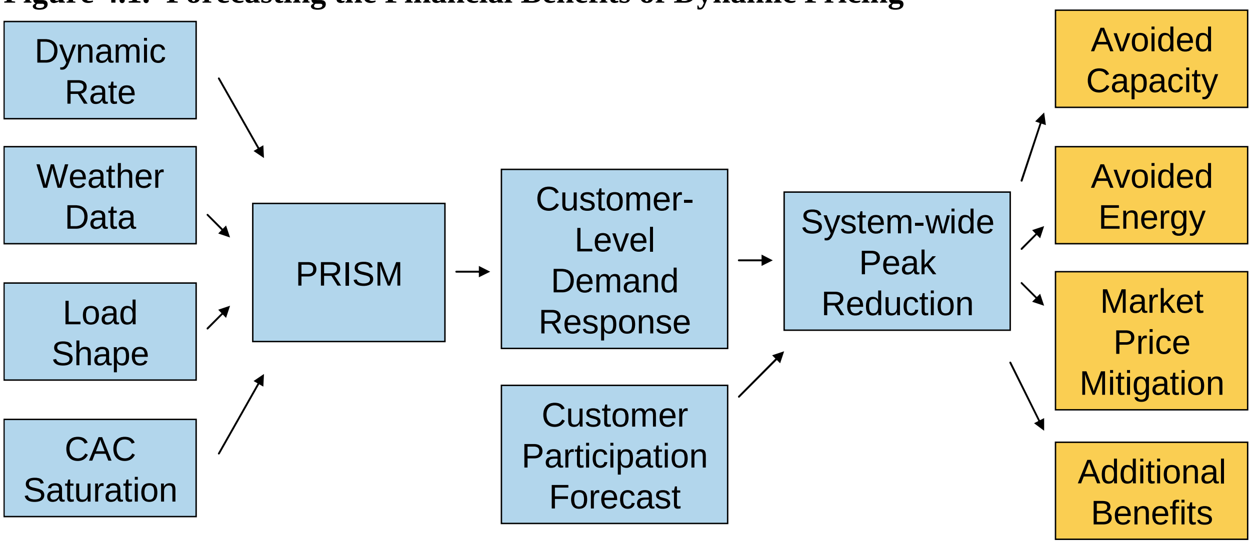
Deployment of AMI will allow PHI to provide dynamic rates to all of its distribution customers.[16] This is expected to yield additional significant reductions in peak demand beyond those that would be achieved through energy efficiency and direct load control programs alone. Specifically, dynamic pricing would allow PHI to provide customers with time-varying rates that can be varied in response to situations in which the market price of electricity is high, or in response to conditions that would lead to decreased system reliability, such as unit outages. Dynamic rates typically provide a strong incentive to the customer to reduce demand during a utility-specified "critical peak period." This incentive could be in the form of a higher price during that period (accompanied by a discount during the non-critical hours) or in the form of a rebate for every kWh that is conserved during the critical-peak hours relative to a customer baseline usage level. Either way, the rates are designed to provide peak reductions to the utility when they are needed most, while at the same time giving the utility's customers the opportunity to achieve bill savings.

The purpose of this section is to quantify the peak reductions that PHI might expect to achieve by providing a dynamic pricing option to its customers. Much of this analysis relies on a model for predicting customer demand response to time-varying and dynamic rates (The Price Impact Simulation Model, or "PRISM") that was developed during the California Statewide Pricing Pilot (SPP). In order to yield meaningful information for companies in the PHI footprint, the PRISM model has been calibrated to PHI's system characteristics, such as weather conditions,

[16] PHI's AMI rollout is currently scheduled to begin in 2009 and continue through the end of 2012. AMI will be deployed in five of PHI's jurisdictions (Pepco MD, Pepco DC, Delmarva MD, Delmarva DE, and Atlantic City Electric).

load profiles, saturation of central air conditioning ("CAC") and existing rates. With these inputs, PRISM is used to forecast the customer-level peak demand reductions that would occur in response to various PHI-specific dynamic rates. When combined with a forecast of the number of customers participating in the rate, the result is a system-wide forecast of annual peak demand reductions. The peak demand reductions is expected to yield supply-side benefits, such as lower capacity and energy costs, as well as other additional benefits like wholesale market price mitigation. Figure 4.1 summarizes this process.

Figure 4.1. Forecasting the Financial Benefits of Dynamic Pricing



4.2. DESCRIPTION OF PRISM

PRISM was developed during the California SPP.[17] The purpose of the SPP was to measure the change in consumption patterns that customers would exhibit when the structure of their rate was changed from a non-time varying rate to one that was time varying and dynamic, such as critical peak pricing (CPP). The experiment involved over 2,500 residential and small commercial and industrial (C&I) customers and spanned a period of more than two years. Ultimately, the SPP produced estimates of customer response to dynamic rates. These estimates varied not only with the dynamic rate design (i.e. price level during the critical peak and off peak periods) but also with information about the region's average load profile, weather, and CAC saturation. It is because of this additional functionality that PRISM's estimations of demand response can reflect not only California-specific conditions, but also be calibrated to provide an estimate of demand response in PHI's service territories.

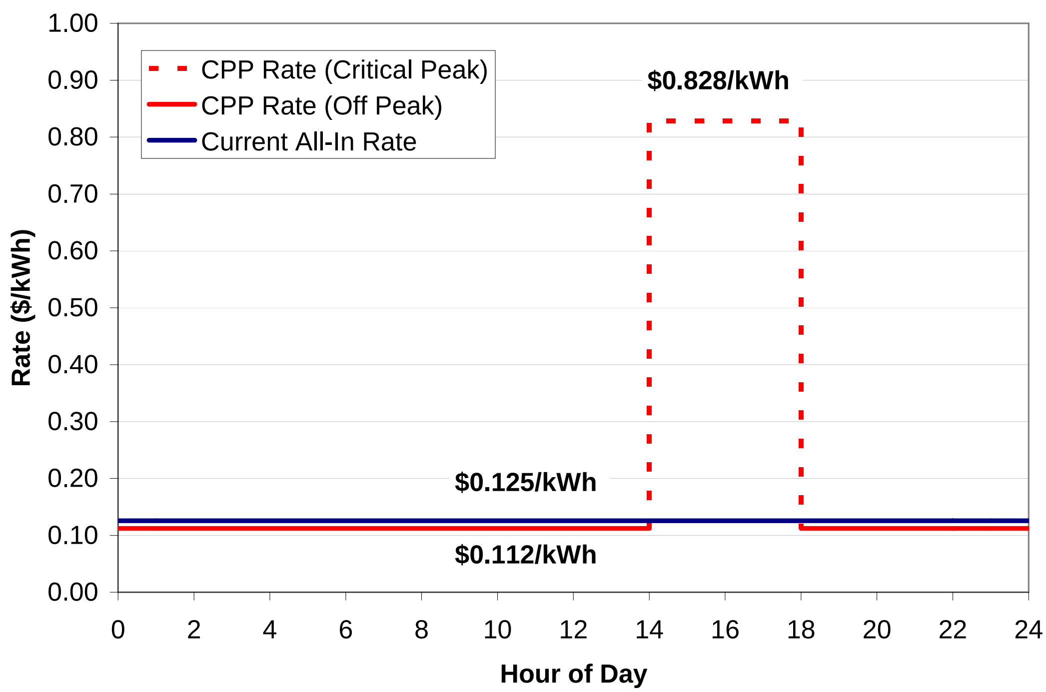
[17] For more information on the California SPP, see CRA International, "Impact Evaluation of the California Statewide Pricing Pilot," March 16, 2005. (http://www.energy.ca.gov/demandresponse/documents/group3_final_reports/2005-03-24_SPP_FINAL_REP.PDF). See also Ahmad Faruqui and Stephen George, "Quantifying Customer Response to Dynamic Pricing," The Energy Journal, May 2005.

Inputs to PRISM were developed using data specific to PHI's service territories. The development of each input and their relevance to the modeling effort are described in the following sections.

4.2.1. The Representative Dynamic Rate

In order to estimate the impacts of dynamic pricing for PHI, it was necessary to model a specific rate design that would be representative of the type of dynamic rate that customers with AMI might be enrolled in. Examples of dynamic rate designs include real time pricing (RTP), Peak Time Rebate (PTR, also known as Critical Peak Rebate, or CPR), and CPP. For this analysis, we used the CPP rate that was designed by SMPPI as part of the PowerCentsDC Pilot. This rate was selected because it has already been designed to reflect PJM day-ahead market prices. It can also be used conveniently with PRISM, because the California SPP specifically measured customer response to CPP rates. The all-in CPP from the PowerCentsDC Pilot is illustrated in Figure 4.2.

Figure 4.2. Illustration of PowerCentsDC All-in Summer CPP Rate



The CPP rate would charge customers around $0.83/kWh during critical peak hours, representing a surcharge of $0.70/kWh over the current all-in rate of $0.125/kWh. In return, customers are given a discount of about $0.013/kWh discount during all other hours of the summer (which represent 2,880 hours or over 98 percent of the total hours in the summer).

This CPP rate is designed to be revenue neutral for Pepco DC's residential customer base. This means that the utility would not gain or lose revenues if all residential customers were enrolled in the CPP rate (in the absence of any changes to consumption patterns). In other words, the average customer's electric bill would not change if he switched from his current rate to the new CPP rate. Roughly half of the customers would be expected to experience bill increases (the customers with "peakier" load shapes), and the other half could expect bill savings (customers with flatter load shapes). Of course, this is all in the absence of demand response. As customers change load patterns in response to the new CPP rate, a higher percentage will see bill savings.

The CPP rate represented here is the all-in rate. It includes transmission, distribution, and other charges in addition to the generation rate. These charges, derived from Pepco DC's current Schedule "R" summer residential rate, are as follows:

- Fixed charge = $3.31/month
- Transmission charge = $0.004/kWh (applied to usage in excess of 30 kWh)
- Distribution charge = $0.0095/kWh (in excess of 30 kWh and less than 400 kWh) and $0.0285/kWh (in excess of 400 kWh)
- Other charges and credits = $0.009/kWh (applied to all usage)

These charges are used to calculate the non-generation portion of the average customer's bill (assuming monthly consumption of 1,048 kWh). This bill is then divided by consumption to arrive at the $/kWh non-generation charge of $0.037/kWh that is added to the generation-only CPP charge.

This CPP rate design was used for residential and small C&I customers in all five of PHI's jurisdictions for analysis purposes. However, because the rate is currently designed to be revenue neutral for Pepco DC's residential customers, it must be altered to reflect differences in the current rates for customers in other jurisdictions. To do this, both the critical peak rate and the off peak rate were simply scaled up or down using the ratio of the jurisdiction's existing all-in rate relative to that of Pepco DC.[18] The resulting CPP rates for each jurisdiction and customer type are summarized in Table 4.1.

[18] More detail on the calculation of the existing all-in rate will follow in a later section.

Table 4.1. Summary of CPP Rates ($/kWh)

	Existing All-In Rate	New CPP Rate	
	All Hours	Critical Peak	Off Peak
Pepco DC			
Residential	0.125	0.828	0.112
C&I	0.160	1.055	0.143
Pepco MD			
Residential	0.158	1.041	0.141
C&I	0.147	0.969	0.131
Delmarva DE			
Residential	0.143	0.946	0.128
C&I	0.115	0.758	0.103
Delmarva MD			
Residential	0.145	0.954	0.129
C&I	0.166	1.096	0.149
Atlantic City			
Residential	0.165	1.088	0.148
C&I	0.163	1.074	0.146

The CPP rate is assumed to be dispatched on 12 critical days during the summer. Since each critical event lasts four hours, this represents a total of 48 critical hours during the summer. During the remaining 2,880 hours of the summer,[19] customers receive the discounted off-peak price. Customers are notified the day before a critical event will be dispatched. More detail on the CPP rate design can be found in Pepco's July 2007 list of rate schedules.[20]

4.2.2. Residential Load Shapes

Load shapes for the average residential customer are used to determine the kilowatt-hour per hour impacts that are produced by each customer in response to the CPP rate. In other words, PRISM produces an estimate of the percent reduction in peak demand that each customer will provide, but the average load shapes for PHI's customers are necessary to translate this into a unit impact that is specific to PHI.

For the residential customers, historical load profile data for the average Schedule "R" customer in each jurisdiction was used to develop the average load shapes.[21] Average hourly consumption is calculated for two periods – the critical peak and the off peak – for the period from June to September 2006 using the load profile data.[22] The results are summarized in Table 4.2.

[19] The analysis of load reductions likely to be achieved by CPP assumes four-hour events, but the benefits component of this study assumes the same level of load reductions would be extended to five hours in order to be consistent with the *Brattle*-PJM-MADRI study, from which some of the customer benefits are derived.

[20] Pepco DC Rates and Regulatory Practices Group, "Rate Schedules for Electric Service in the District of Columbia," July 2007.

[21] Based on load profile data collected between 1990 and the current date.

[22] Critical days are identified as the 12 non-holiday weekdays with the highest maximum daily temperature.

Table 4.2. Average Residential Load Shapes (June – September)

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Avg Hrly Critical Peak Consumption (kWh/hr)	1.91	2.90	1.92	2.48	2.13
Avg Hrly Off Peak Consumption (kWh/hr)	1.42	1.52	1.10	1.25	1.09

4.2.3. Commercial and Industrial Customers' Load Shapes

Average C&I load shapes are needed to produce kilowatt-hour per hour peak reduction estimates for the C&I customers. In calculating the load profiles, it is important only to include customers that will be equipped with AMI. Although PHI's largest customers will also be equipped with AMI, they are not included because they already have interval meters. While these customers could still enroll in a dynamic rate, their peak reductions are not considered to be additionally enabled by AMI and therefore are not included in the analysis. The peak demand "cutoff" point above which C&I customers would not be equipped with AMI varies by utility as follows: 500 kW for Pepco DC and Pepco MD, 300 kW for Delmarva DE and Delmarva MD, and 1 MW for ACE.

The remaining non-interval metered customers could be on one of a number of different rate schedules. This is unlike the residential customers who are primarily on the "R" schedule. Thus, it was necessary to calculate a weighted average load profile across the rate schedules within each jurisdiction, using the number of non-interval metered customers on each rate schedule as the weights. The resulting C&I load shapes are summarized in Table 4.3.

Table 4.3. Average Non-Interval Meter C&I Load Shapes (June - September)

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Avg Hrly Critical Peak Consumption (kWh/hr)	17.90	18.20	8.06	4.20	4.97
Avg Hrly Off Peak Consumption (kWh/hr)	12.47	12.03	5.43	2.99	3.18

4.2.4. Existing All-In Rates

The existing rate is a necessary input to the analysis, because a customer's responsiveness to a new CPP rate will be driven by the price increase or decrease that the CPP rate provides relative to the customer's existing rate. In other words, during the critical peak hours, a customer is responding not just to the high absolute price level of the CPP, but to the relationship of that price to the existing rate. Similarly, in the off peak, the customer's response is assumed to be driven by the relative discount that he or she receives through the CPP rate.

Existing all-in rates were calculated for the average residential and C&I customers in all five jurisdictions. For residential customers, the “R” rate schedule for each jurisdiction was used to calculate the average customer’s monthly summer electricity bill. The average monthly consumption estimates that were used to calculate this bill were presented in Table 4.4. Once the total bill was calculated, it was divided by the monthly consumption to arrive at an all-in rate expressed in dollars per kilowatt-hour. Table 4.4. below summarizes the existing residential rates by jurisdiction.

Table 4.4. Existing Residential All-In Summer Rates

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Rate Schedule	"R"	"R"	"R"	"R"	"RS"
Avg Summer Bill ($/Month)	132	178	118	133	133
All-In Rate ($/kWh)	0.125	0.158	0.145	0.143	0.165

Existing C&I rates were calculated in a similar manner. The difference with the C&I customers, as mentioned previously, is that they are spread across different rate classes. As a means of approximately representing the typical C&I electricity rate, we identified the single rate schedule with the largest share of non-interval metered C&I load and used that rate schedule to calculate the monthly summer bill for the average customer. This bill was divided by the monthly consumption numbers previously shown in Table 4.3. to arrive at the existing all-in rate. These rates are summarized in Table 4.5. for each jurisdiction.

Table 4.5. Existing C&I All-In Summer Rates

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Rate Schedule	"GT LV"	"MGT LV II"	"SGS-S I"	"MGS-S"	"MGS-S"
Avg Summer Bill ($/Month)	1,469	1,303	665	253	382
All-In Rate ($/kWh)	0.160	0.147	0.166	0.115	0.163

4.2.5. Saturation of Central Air Conditioners

The CAC saturation of a region can be expected to influence its expected peak reduction. Generally, customers with CAC have a greater ability to reduce consumption during peak times, because they can have direct control over their thermostat (and in many cases can even program the thermostat to automatically increase the temperature and thus reduce electricity consumption during the peak period of the day). Thus, all things being equal, in a region where a large percentage of customers have CAC, the expected peak demand reduction will be higher than in a region where a small percentage of customers have CAC.

CAC saturation rates for the five jurisdictions were provided by PHI and are summarized in Table 4.6.

Table 4.6. CAC Saturation Rates

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Residential					
CAC	45%	66%	42%	42%	N/A
Heat Pump	11%	19%	11%	11%	N/A
Total	56%	84%	53%	53%	55%
C&I					
Total	97%	97%	97%	97%	97%

4.2.6. Temperature Statistics

Temperature has also been found to be correlated with peak reductions from dynamic pricing. Generally, hotter regions tend to experience greater peak reductions. Two specific temperature statistics are used as inputs to PRISM: peak vs. off peak temperature differentials and the average daily temperature.[23] These statistics have been computed using historical hourly temperature observations from the following locations:

- Salisbury, MD
- Wilmington, DE
- Atlantic City, NJ
- Reagan National Airport, DC

[23] It should be noted that humidity could also have an additional impact on the expected peak reductions. However, because PRISM is based on a study conducted in California, where humidity levels are low and do not vary greatly from region to region, it does not account for the potential influence of humidity.

4.3. CUSTOMER-LEVEL IMPACTS

Using the previously described inputs, peak demand impacts were simulated for the average residential and C&I customers in each of the five jurisdictions. These impacts are summarized in Figure 4.3 and Figure 4.4.

Impacts for C&I customers are estimated to be 30 percent of the impacts for a residential customer on the same rate. In other words, if a residential customer were to reduce peak demand by 10 percent in response to dynamic pricing, a C&I customer on the same rate would reduce peak demand by 3 percent. This is a conservative estimate that is supported by the findings of the C&I impacts study that was conducted through the California SPP.[24]

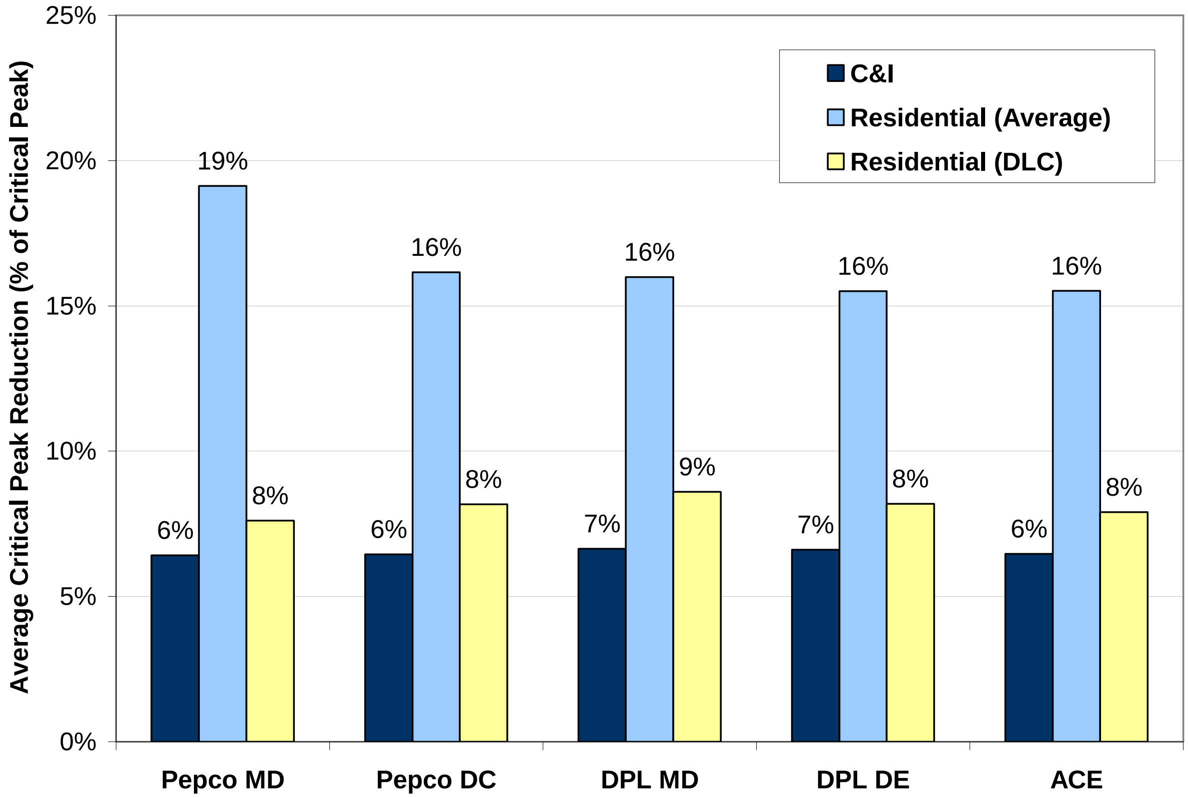
A share of PHI's customers will be participating in a direct load control (DLC) program. Through this program, PHI would control the participating customers' CAC systems through a device called a "smart thermostat" and would have the ability to reduce the customers' CAC load on peak days through the thermostat. It is important not to double-count the CAC-related peak reductions for these customers by attributing their impacts to both the DLC program and to dynamic pricing. Thus, for the purposes of this analysis, the CAC-related peak reductions from these customers will not be counted toward the CPP rate. However, the DLC customers would still have the opportunity to participate in the CPP rate and could further reduce their consumption by other end uses in response to the dynamic rate.[25] These incremental peak reductions should be attributed to the CPP. To account for this, the residential DLC customers are modeled as customers who do not have CAC. As a result, their peak demand impact represents the expected reduction at the other end uses and is smaller than that of the average customer. Expected impacts for these customers are also presented in Figure 4.3 and Figure 4.4.

To remain conservative in our estimation of peak reductions, C&I customers participating in the DLC program have been excluded entirely from the analysis of dynamic rates. In other words, these customers' CAC peak demand reduction is attributed to the DLC program, and they are not assumed to provide an additional demand reduction that can be attributed to the dynamic rate.

[24] See CRA International, "California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update," June 2006.

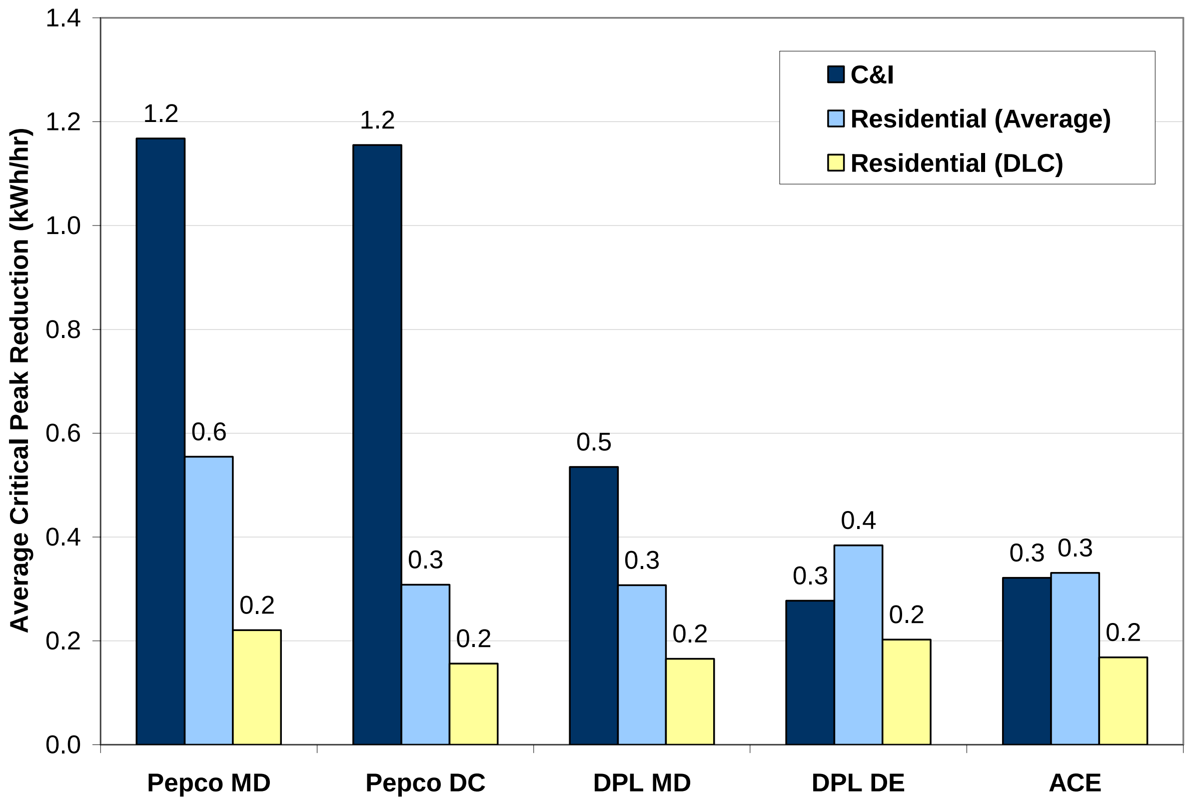
[25] For example, customers could refrain from running their clothes dryers until after the critical peak period ends. This would represent a peak demand reduction incremental to any reduction that would be attributable to the DLC program, which only has an impact on load created by the CAC system.

Figure 4.3. Expected Average Critical Peak Reductions (Percent of Critical Peak)



The higher expected peak reduction from Pepco MD's customers (on a percentage basis) can be explained by the higher CAC saturation rate in that jurisdiction. In all jurisdictions, the average residential customer is expected to produce a greater peak reduction on a percentage basis than that the peak reduction from the average C&I customer. However, this does not always translate into a greater peak reduction on kilowatthours-per-hour basis. This depends on the size of the customer. In fact, in three out of the five jurisdictions, the larger size of C&I customers leads to a greater kilowatthours-per-hour reduction per customer.

Figure 4.4. Expected Average Critical Peak Reductions (kWh/hr)



Due to the larger size of C&I customers in Pepco's jurisdictions, these customers are expected to produce the largest average peak reductions. Critical peak reductions from other customers range from 0.2 kWh/hr to 0.6 kWh/hr.

4.4. FORECASTING CUSTOMER PARTICIPATION

The estimates of the peak kilowatt reductions per customer can be combined with a forecast of the number of customers participating in the dynamic rate. The result is an annual system-wide forecast of peak impacts for each jurisdiction. The following sections describe the assumptions used in developing the forecast of participating customers.

4.4.1. Customers Eligible for AMI

Customers can only enroll in a dynamic rate if they are equipped with AMI, because this allows their electricity consumption to be measured in hourly intervals (or shorter) as opposed to being measured on a monthly basis. All residential customers will be equipped with AMI. Of the C&I customers, only those without interval meters will be equipped with AMI.[26] The number of

[26] C&I non-interval meter services are used as an approximate representation of the number of eligible C&I customers.

eligible customers is summarized in Table 4.7, along with the annual growth rates that are assumed for each segment of the population.

Table 4.7. 2006 Customer Population Estimates and Annual Growth Rates

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Residential					
Total	211,220	469,138	169,993	262,684	474,921
Annual Growth Rate	2.0%	0.8%	1.4%	0.9%	1.6%
C&I					
Total (Non-Interval)	24,704	45,248	27,312	32,625	53,096
Annual Growth Rate	0.9%	0.5%	1.4%	1.3%	1.0%

4.4.2. AMI Deployment Schedule

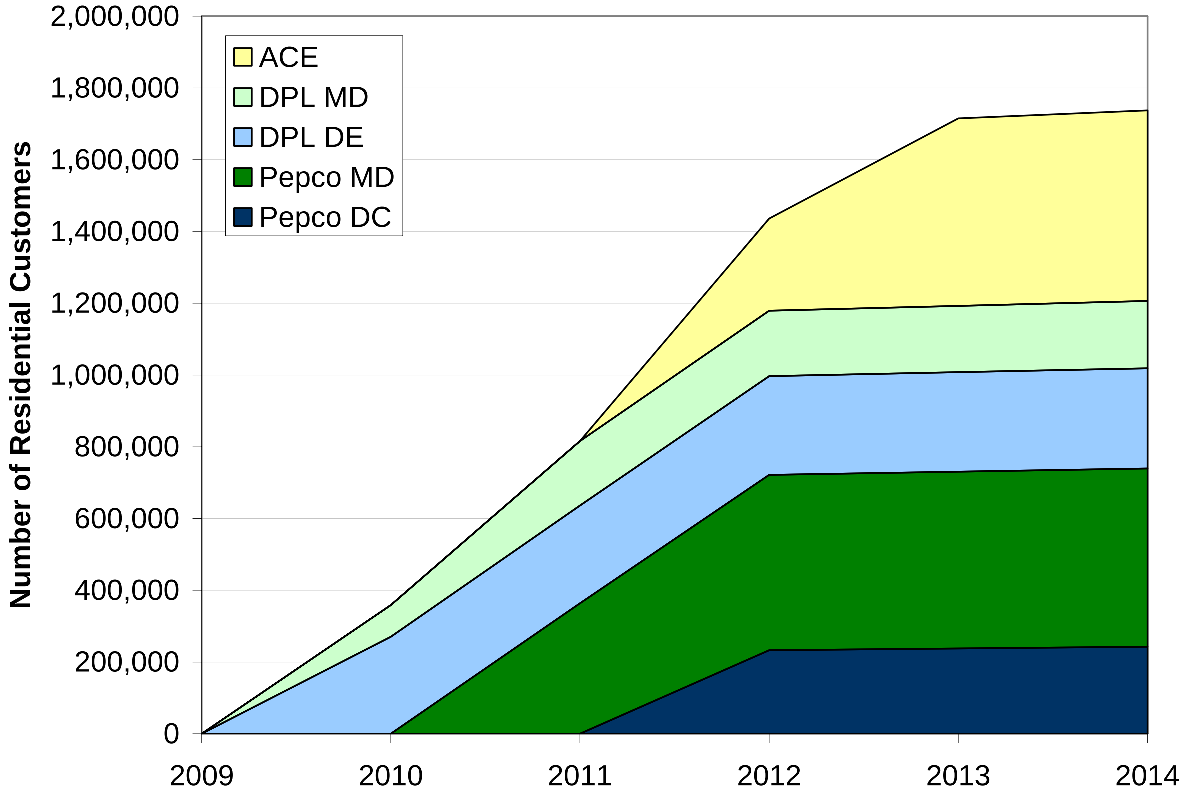
The current plan is to deploy AMI to customers over the period from 2009 to 2013. The deployment schedule varies by jurisdiction. It is assumed that customers are eligible to participate in dynamic pricing once they have been equipped with AMI. In other words, it is not necessary for a jurisdiction to achieve 100 percent of its scheduled deployment before customers can begin enrolling in the CPP rate. Table 4.8 below summarizes the AMI deployment schedule and Figure 4.5 and Figure 4.6 combine this with the population forecasts to show the total number of customers equipped with AMI in each year from 2009 until full deployment in 2013.[27]

Table 4.8. Mid-Year AMI Deployment Schedule (Residential and C&I)

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
2009	0%	0%	25%	50%	0%
2010	0%	38%	75%	100%	0%
2011	50%	88%	100%	100%	25%
2012	100%	100%	100%	100%	75%
2013	100%	100%	100%	100%	100%

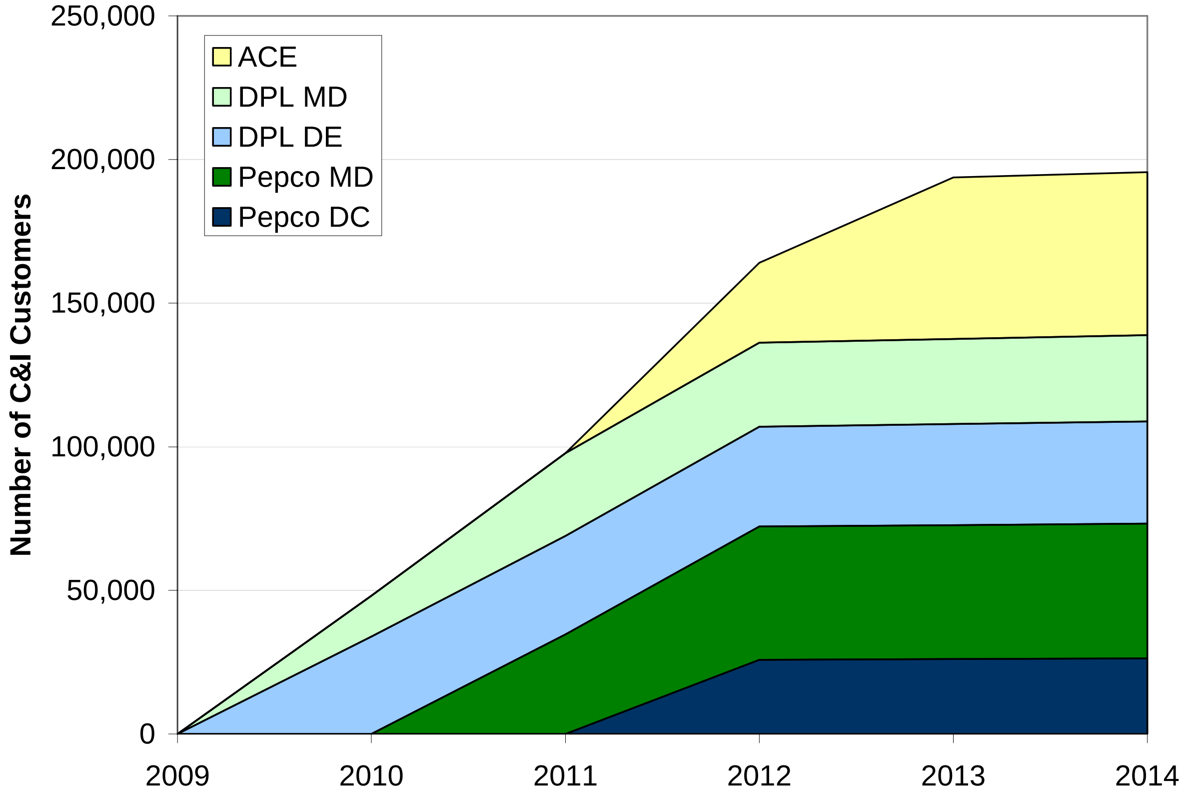
[27] It should be noted that PHI provided an end-of-year AMI deployment schedule, and a mid-year schedule was used in the analysis to approximate the number of customers with AMI during the summer CPP season. Mid-year values were obtained through linear interpolation.

Figure 4.5. Forecast of Residential Customers Equipped with AMI



By the end of 2013, over 1.7 million residential customers are expected to be equipped with AMI. Both Pepco MD and ACE are anticipated to have deployed AMI to around 500,000 residential customers, accounting for nearly 60 percent of PHI's total residential deployment.

Figure 4.6. Forecast of C&I Customers Equipped with AMI



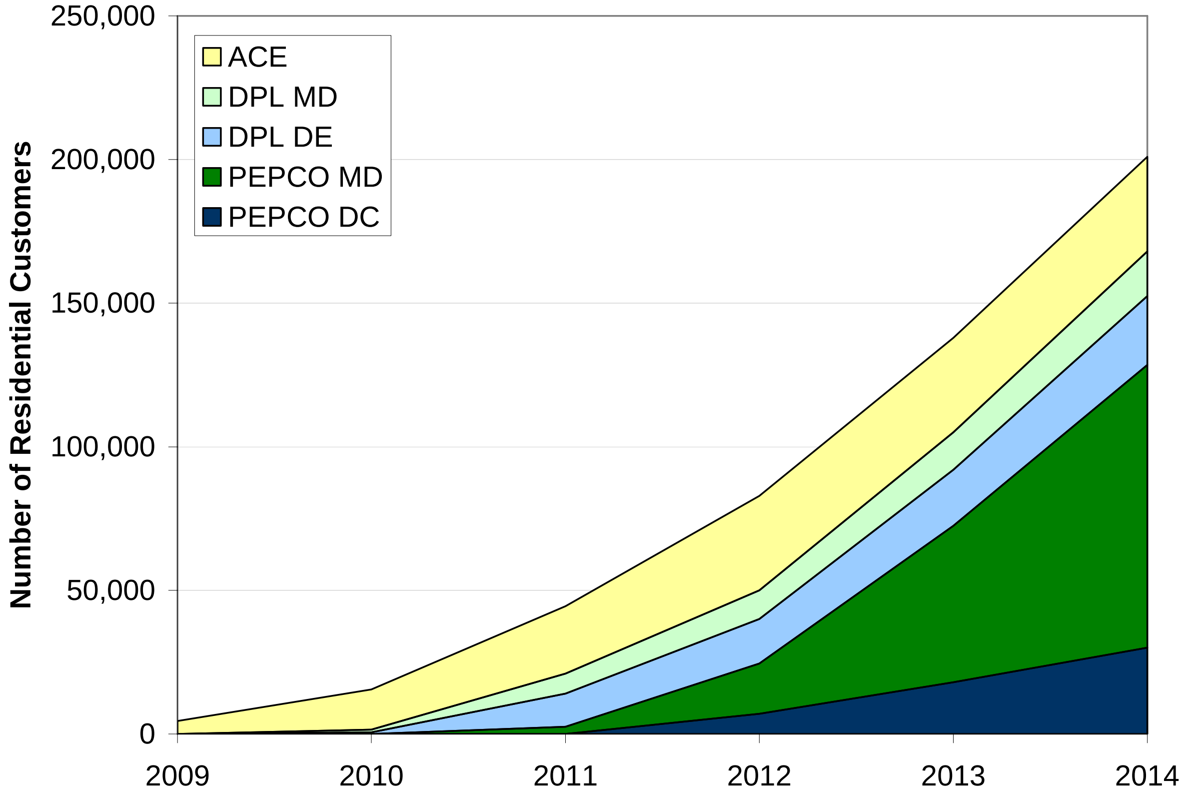
Nearly 200,000 C&I customers will be equipped with AMI in PHI's service territories by the end of 2013. Over 50,000 C&I customers in ACE will be equipped with AMI, representing nearly 30 percent of the total non-interval meter C&I deployment.

4.4.3. Customer Participation in Direct Load Control

As was described previously, peak impacts from DLC customers must be treated differently than the other customers due to the fact that their CAC-related peak reductions are not attributable to the CPP rate. Thus, a separate forecast of the number of DLC customers is needed. Figure 4.7 and Figure 4.8 below summarize this forecast for residential and C&I customers, as provided by PHI.[28]

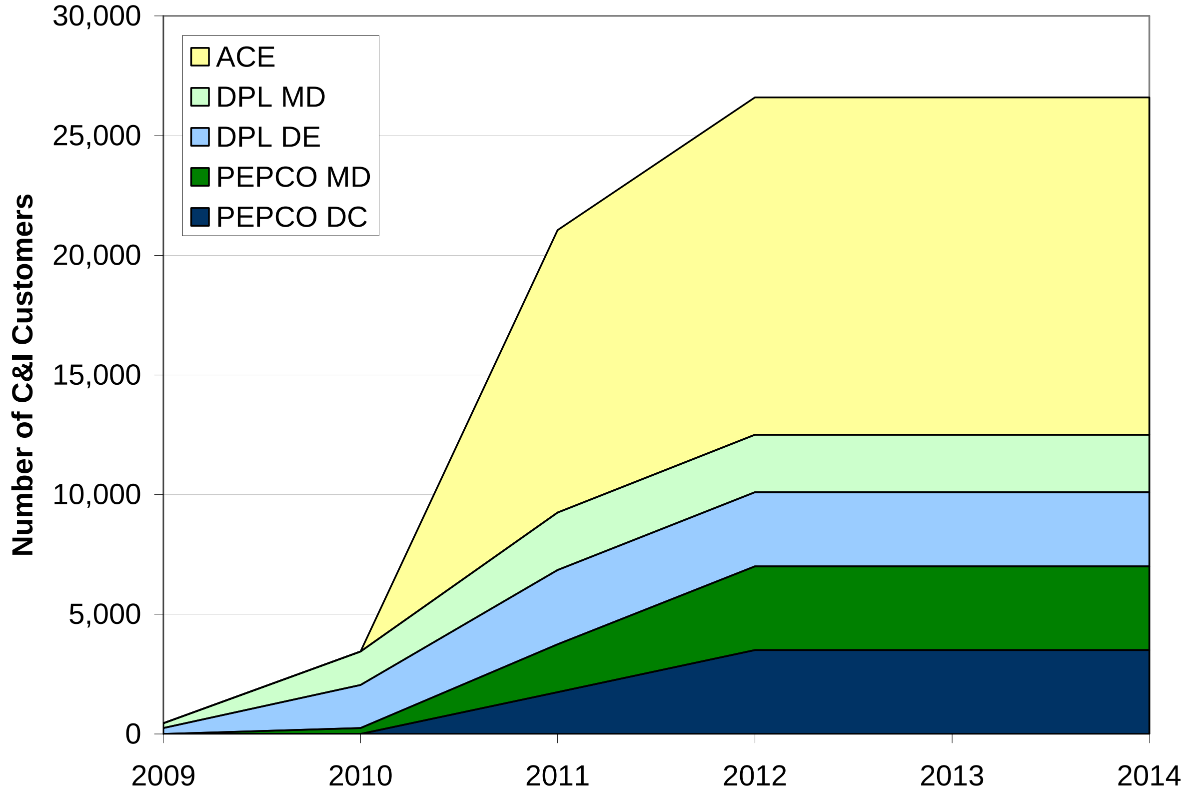
[28] It is assumed that all C&I DLC customers are equipped with AMI rather than interval meters.

Figure 4.7. Forecast of Participation in PHI's Residential DLC Program



Nearly 200,000 residential customers are expected to be participating in the DLC program by the end of 2014. The forecast is designed to coincide with the AMI deployment schedule. It is important to note that 100 percent of DLC customers are assumed to participate in the dynamic rate. This is because, due to the peak reduction that these customers automatically provide through the DLC program, they are in a position to realize instant bill savings under the dynamic rate and would not have an incentive to remain on the original rate.

Figure 4.8. Forecast of Participation in PHI's Non-residential DLC Program



Over 25,000 C&I customers are expected to participate in the non-residential DLC program by the end of 2013. ACE is forecasted to have over half of all participants. All of the non-residential DLC customers are assumed to be enrolled in the dynamic rate, but their impacts are not counted toward the system-wide peak reduction attributable to dynamic pricing. This is done to avoid double-counting with DLC peak impacts that are reported separately.

4.4.4. Enrollment Rate

Enrollment in the dynamic rate will depend heavily on how the rate is offered to PHI's customers. For example, it could be offered as the default rate, where all customers are put on the dynamic rate with the option of switching back to their original rate.[29] The expected participation resulting from this type of offering would be much higher than if the dynamic rate were offered on a voluntary basis, where customers were simply provided with the option of signing up for the rate and otherwise would stay on the existing rate structure. There is a significant amount of uncertainty around what enrollment would be like under these various

[29] There are many ways in which customers could be phased into such a rate offering. For example, if all customers were initially placed on the dynamic rate, they could be given full bill protection for the first year of enrollment and this bill protection could be phased out over a three to five year window. This would ensure that customers would understand the potential benefits of the new rate before making a decision on whether to stay on the new rate or switch over to a flat rate.

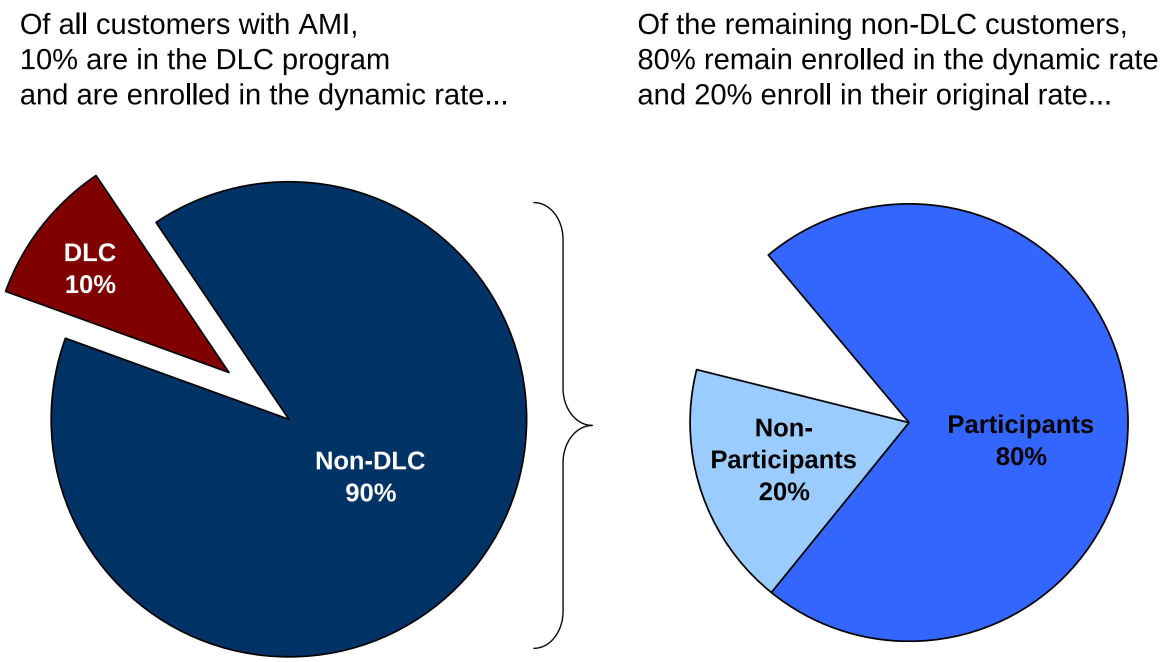
scenarios. Studies have suggested that under the “CPP-Default” scenario, 80 percent of eligible customers could remain on the dynamic tariff. The “CPP-Voluntary” scenario, on the other hand, might lead to only around 20 percent participation in the rate. Due to the wide range of uncertainty surrounding this assumption, we have chosen to analyze the system-wide peak impacts under these two polar scenarios, assuming the participation rates described above.

These participation rates are not anticipated to be achieved in the first year of the study. In the case of the CPP-Default scenario, enrollment will ramp down from 100 percent in the first year (2009) to 80 percent by 2013. Similarly, for the CPP-Voluntary scenario, participation ramps up from zero to 20 percent by 2013.

It should also be noted that in PHI’s service territories, customers have the option of “shopping” for another retail supplier of electricity. PHI expects that some customers will exercise this option. For the purposes of this analysis, it is assumed that the alternative retail supplier will offer a dynamic pricing scheme similar to the one being modeled, and that the customers who shop will adopt the dynamic pricing option at the same rate as those customers who do not shop. Due to the fact that the AMI deployment has enabled these customers to enroll in the dynamic rate, their impacts are included in the final estimation of peak demand reductions even though PHI is no longer their supplier.

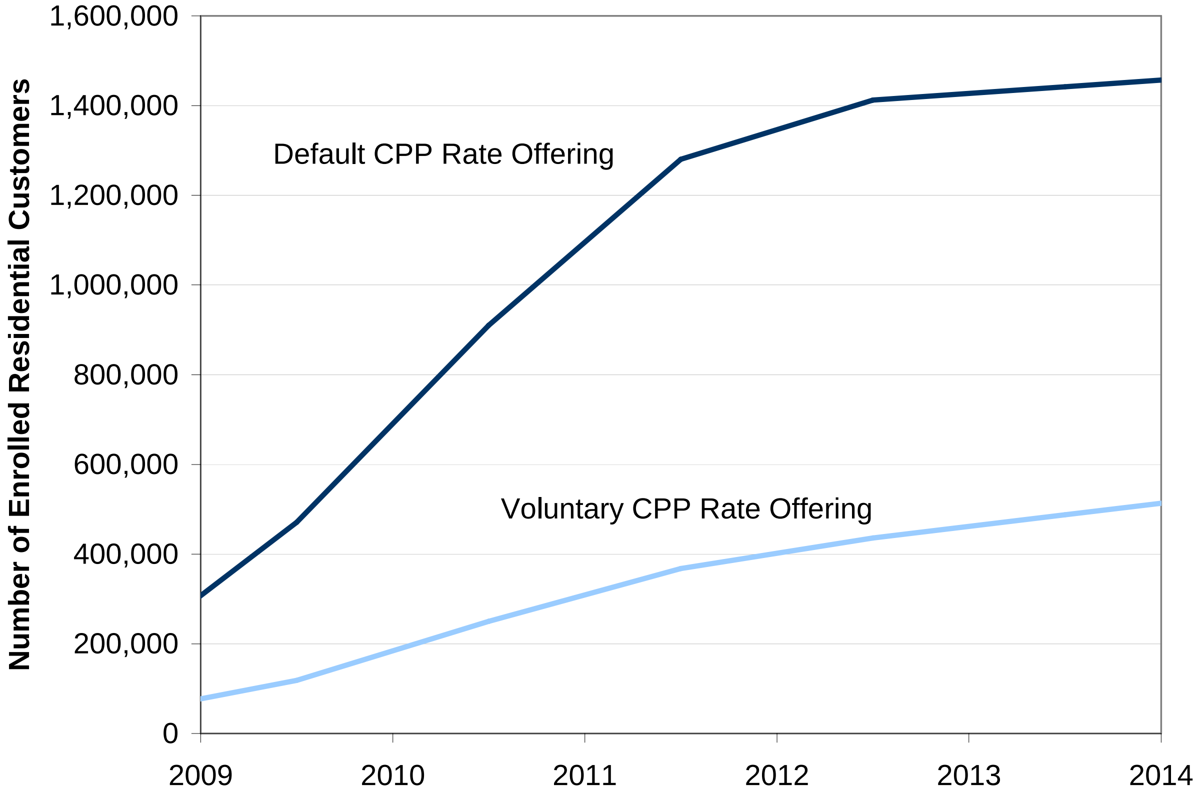
For an illustration of how these factors would determine the number of participating customers, see Figure 4.9. It illustrates the breakout of residential DLC customers, participants, and non-participants under the CPP-Default scenario for Pepco DC in 2013. In this scenario, 82 percent of all residential customers would participate in the dynamic rate.

Figure 4.9. Share of Participating Residential Customers in Pepco DC in 2013 (CPP-Default Scenario)



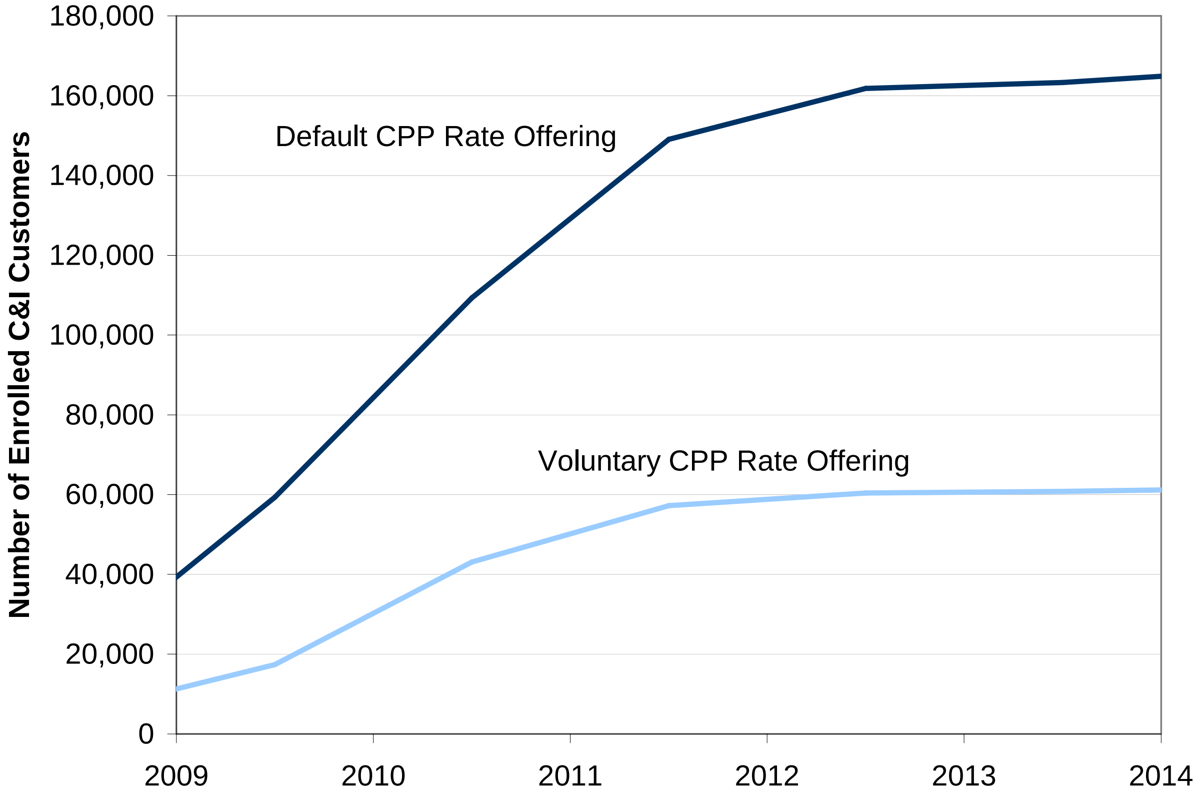
With all of these factors accounted for, the result is a forecast of residential and C&I customers enrolled in the CPP rate in both the CPP-Default scenario and the CPP-Voluntary scenario. These forecasts are summarized in Figure 4.10 and Figure 4.11 below.

Figure 4.10. Forecast of Total Residential CPP Enrollment in All PHI Jurisdictions



Over 1.4 million residential customers are expected to enroll in the dynamic rate by the end of 2013 if it is offered as the default rate. Around 500,000 are expected if it is offered as a voluntary rate.

Figure 4.11. Forecast of Total C&I CPP Enrollment in All PHI Jurisdictions

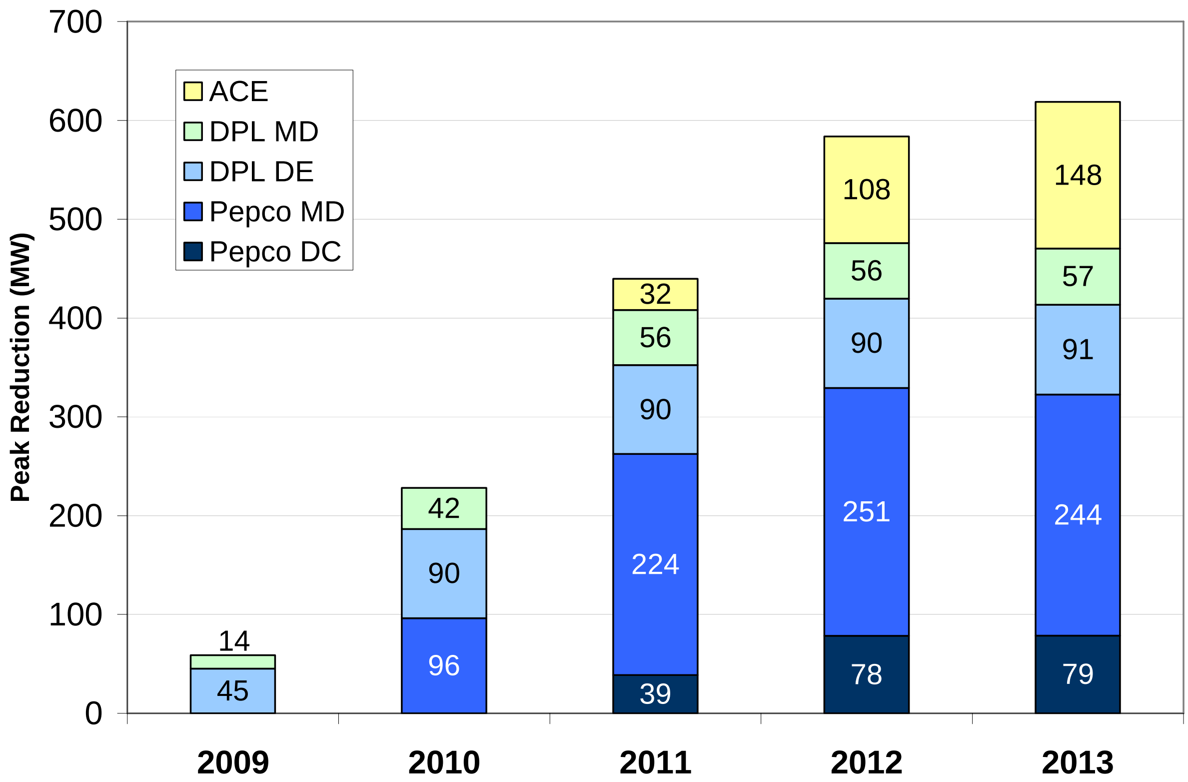


Over 160,000 C&I customers are expected to enroll in the dynamic rate by 2013 if it is offered as the default rate. Approximately 60,000 are anticipated to enroll if it is offered as a voluntary rate.

4.5. SYSTEM-WIDE PEAK DEMAND IMPACTS OF DYNAMIC PRICING

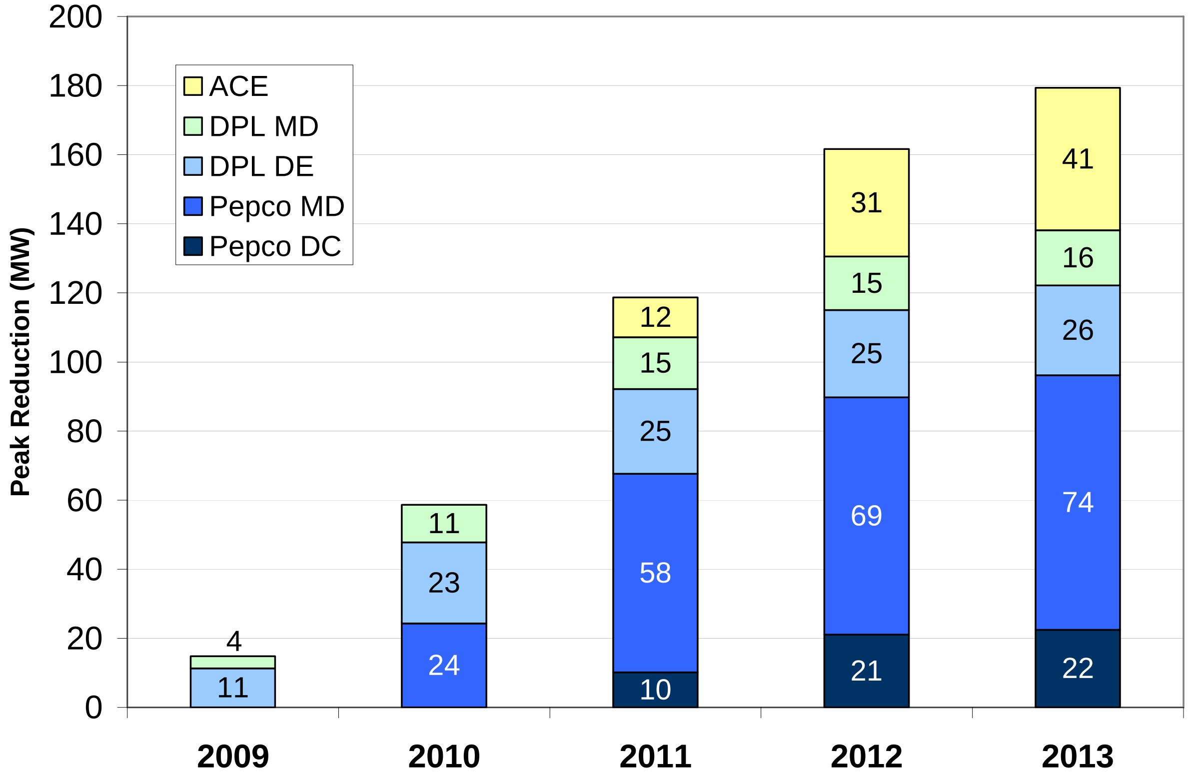
Multiplying the per-customer kilowatthours-per-hour peak reductions by the forecast of participating customers results in an annual forecast of system-wide peak demand reductions for PHI's service territories. These forecasts are summarized in Figure 4.12 for the CPP-Default scenario and Figure 4.13 for the CPP-Voluntary scenario.

Figure 4.12. System-Wide Peak Demand Reductions Attributable to Dynamic Pricing
CPP-Default Scenario



Under the CPP-Default scenario, the total peak reduction attributable to dynamic pricing will be nearly 60 MW in 2009, the first year of AMI deployment. This is expected to grow to over 600 MW by 2013. Nearly 40 percent of the 2013 demand reduction comes from Pepco MD.

Figure 4.13. System-Wide Peak Demand Reductions Attributable to Dynamic Pricing
CPP-Voluntary Scenario



The CPP-Voluntary scenario provides significantly smaller reductions in peak demand (note the difference in the figure's y-axis scale compared to the figure showing impacts for the CPP-Default scenario). The expected forecast is for 15 MW of peak reduction in 2009, growing to nearly 180 MW by 2013. By the end of 2013, the peak reductions are less than 30 percent as large as those under the CPP-Default scenario. This is driven by the much lower participation rate.

5.0 RESOURCE COST SAVINGS

Ongoing DSM creates lasting value by reducing the amount of physical capacity that needs to be built to reliably meet peak load, and by reducing the amount of generation (the value of which is partially offset by the lost value of service to the customer) and ancillary services required from physical resources. Customers benefit by having to buy a lesser volume of capacity and energy and by being able to sell ancillary services.

5.1. CAPACITY SAVINGS

5.1.1. Theory

Reducing peaks loads reduces the amount of capacity that load serving entities (and ultimately customers) are required to purchase in order to maintain resource adequacy for reliability, eventually resulting in fewer new generation plants having to be built and enabling the retirement of the most expensive, dirtiest old plants. The annual customer savings is given by the product of the annual MW reduction in capacity requirements and the $/MW-year value of capacity.

The annual reduction in physical capacity requirements can be estimated by assuming that all expected DR would provide capacity or reduce the load forecast, thus avoiding the need for physical capacity to the extent that the simultaneous peak load forecast is reduced in each PJM locational delivery area (LDA), multiplied by 1 plus the reserve margin. The reduction in simultaneous peak load forecast is given by the sum of projected peak load reductions in all jurisdictions (shown in Figure 5.1) discounted by a load diversity factor representing the fact that not all jurisdictions' peak loads coincide with the system peak.

Peak load reductions are adjusted by a reserve margin to account for the fact that some capacity is maintained as a buffer above the expected peak load in order to meet a desired level of reliability. The most commonly used reserve margin metric, the installed reserve margin (IRM), is one of the key parameters of PJM's RPM capacity market (currently 15 percent).

The value of an incremental reduction in capacity requirements is given by the market price for capacity. The market price for capacity is what retail providers or wholesale suppliers of standard offer service would otherwise pay for incremental capacity and presumably pass on to the customer. Hence, estimating customers' capacity savings requires estimating the expected annual capacity price.

Actual capacity prices are determined by PJM's reliability pricing model and market factors including load growth, DSM penetration, boom and bust cycles of construction, environmental regulations, the cost of new capacity, and other factors that are difficult to predict accurately for any given future year. In expectations, however, it is reasonable to assume that, barring barriers to entry, future markets will be in a competitive equilibrium in which suppliers earn their cost of capital, i.e., they neither over-invest and earn less than their cost of capital in a surplus market, nor do they under-invest and miss opportunities to make above-market returns in a tight market. At equilibrium, the capacity price should be equal to the Net Cost of New Entry (Net CONE), which can be expected to just cover a generating plant's capital costs and fixed operating and maintenance costs that are not offset by operating earnings from selling energy and ancillary services.[30]

[30] Using Net CONE to value reductions in peak load is more conservative than using CONE, which is often used in DSM cost-effectiveness tests. Net CONE represents the resource cost and the expected capacity price that customers will pay (and avoid). It accounts for the fact that suppliers' operating margins on sales of energy and ancillary services help to offset the cost of building and maintaining a generation plant. Net CONE also represents the net system cost of having a plant online, i.e., the capital and fixed O&M costs less the system cost savings from dispatching the plant when it has a lower variable cost than alternative resources.

The cost of new entry of course varies by technology. However, assuming the market is in an equilibrium in which a mix of technologies is economic to build, all technologies must have the same Net CONE, with the technologies that have relatively high capital and fixed costs enjoying higher operating margins. PJM (and other RTOs) uses the Net CONE for a combustion turbine (CT) as a generic Net CONE in determining the parameters for its Reliability Pricing Model (RPM).

5.1.2. Methodology

In the “Immediate Supplier Reaction” and “Slower Supplier Reaction” scenarios, it is assumed that the market is in equilibrium starting in 2009, with the capacity price set by PJM’s current official estimate of Net CONE. PJM’s current Net CONE is $51/kW-yr in the Eastern MAAC Locational Delivery Area (LDA) and $54.5/kW-yr in the Southwestern MAAC LDA, based on recent CT costs and operating margins.[31] These figures are assumed to stay constant in real terms over the study horizon. Holding PJM’s current Net CONE constant in real terms is highly conservative because it does not account for the dramatic increases in the cost of new capacity that have occurred recently, which will probably lead to substantially higher capacity prices in the future if today’s PJM market prices persist or rise further. A recent *Brattle* study sponsored by the Edison Foundation finds that recent increases in the costs of steel, specialty parts, and specialty labor have increased the cost of new CTs by 17 percent in 2006 and increased the cost of new steam generation by 25-35 percent between 2004 and 2007.[32]

In the “Delayed Supplier Reaction” scenario, the market is assumed to be in a scarcity situation until 2014, when it reaches equilibrium and capacity prices fall to Net CONE. For 2009 through 2013, capacity prices are estimated based on the intersection of projected supply and demand curves. Supply offer curves for 2010/11 and 2013/14 were derived from the 2007/08 offer curve by: (1) removing likely retirements at net avoidable going-forward costs used in PJM simulation for each unit type; (2) adding capacity in advanced stages of project development from PJM Generation Queue; and (3) assuming all other offers stay the same. Demand curves, which PJM refers to as the “Variable Resource Requirement” (VRR), are based on parameters for the 2009/10 base residual auction (BRA). The Reliability Requirement in each LDA is assumed to grow at the rate of peak load growth, as projected by PJM.

Applying the methodology described above to the “Delayed Supplier Reaction” scenario produces capacity prices of $190/MW-day in 2010 and $223/MW-day in 2013 EMAAC and $237/MW-day in 2010 and $239/MW-day in 2013 in SWMAAC. Capacity prices fall to Net CONE in 2014, when it is assumed that sufficient new supply is added to bring the market back to economic equilibrium.

[31] PJM, RPM Planning Period Parameters, http://www.pjm.com/markets/rpm/downloads/planning-period-parameters.xls

[32] See *Rising Utility Construction Costs: Sources and Impacts,* prepared by Prepared by Marc W. Chupka and Gregory Basheda at *The Brattle Group* for The Edison Foundation, September 2007.

5.1.3. Results

Resulting estimates of customer benefits from avoided capacity purchases resulting from PHI's DSM programs are shown for years 2010 and 2013 in Tables 5.1 and 5.2, respectively. 2010 and 2013 are used as representative years from which the benefits in all other years are interpolated and extrapolated based on relative amounts of load reductions.

Tables 5.1 and 5.2 also show the key elements of the calculation that was described in Section 5.1.2. (Note that the peak load and total load estimates are taken from the normalized load data used in the *Brattle*-PJM-MADRI study, and they are not escalated to account for load growth).

Table 5.1. Estimated Capacity Savings in 2010

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	758,523	758,523	758,523	748,357	748,357	748,357
Jurisdictional Reduction (MW)	220	220	220	389	389	389
Reductions Not Offset by Supplier Response	103	220	220	228	389	389
Avoided Capacity Costs (million 2007 $'s)	$11	$11	$16	$20	$20	$28

Table 5.2. Estimated Capacity Savings in 2013

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	737,505	737,505	737,505	711,144	711,144	711,144
Jurisdictional Reduction (MW)	570	570	570	1,009	1,009	1,009
Reductions Not Offset by Supplier Response	101	350	570	119	620	1,009
Avoided Capacity Costs (million 2007 $'s)	$29	$29	$47	$52	$52	$83

5.2. GENERATION SAVINGS

5.2.1. Theory

Reducing low-value or time-flexible uses of electricity during peak periods when prices are very high clearly saves fuel and creates economic value that accrues to customers if rate structures provide the appropriate incentives and rewards.

Generation savings depend on the particular type of generation that is not dispatched as a result of load reductions, which could include a combination of old capacity running less (or retiring) or new capacity not being constructed and dispatched. The value of reduced generation is also partially offset by the value the customer forgoes by not consuming as much power. Assessing the forgone value to the customer is difficult to assess and is highly variable; it also depends on whether the customer shifts load to lower-priced periods.

5.2.2. Methodology

This study estimates generation savings by adopting the results of the *Brattle*-PJM-MADRI study, in which net generation savings amounted to an additional 12-36 percent on top of capacity savings. This study scales the benefits found in the *Brattle*-PJM-MADRI study based on the relative magnitude of load reductions.

It should be noted that although the *Brattle*-PJM-MADRI study was based on a dispatch model that was able to identify the change in generation resulting from DSM, it did not account for the fact that the amount of supply online could eventually change as a result of DSM. The avoided generation necessarily came from reductions in the dispatch of existing (probably old) capacity. Estimated generation savings might have been lower if the analysis had considered the possibility of reduced construction of new (relatively efficient) capacity forcing inefficient existing units to generate power even with DSM.

The *Brattle*-PJM-MADRI study did however account for the value the customer foregoes by reducing or shifting its consumption. A lower bound estimate was established in which customers lose no value, which might be possible if participation in DSM programs stimulates customers to pay attention to their energy usage and eliminate waste they had never considered before. An upper bound estimate valued the lost customer load at the spot price of power (it would be uneconomic to reduce load if the value were any higher). An intermediate value was based on the assumption that customers value their foregone or shiftable load at the minimum retail rate among customer classes, based on the theory that customers consume energy until the marginal value of their least valuable kilowatt-hour equals their retail rate, and the customers with the lowest retail rates have the lowest value marginal uses of energy, and thus are most likely to voluntarily reduce their consumption. The present analysis of PHI's DSM programs uses the intermediate estimate. (To the extent that mass market customers participate in dynamic pricing have a higher retail rate than the rate assumed in the *Brattle*-PJM-MADRI study, the lost customer value might be higher and the net generation savings overstated somewhat).

This approach is roughly applicable whether customers simply eliminate load or whether they shift load to non-peak periods. For example, if a customer reduces consumption valued at $100/MWh when spot prices are $300/MWh, the net savings is $200/MWh even if the customer shifts its consumption (at an inconvenience cost of, say, $20/MWh) to another hour with $80/MWh spot prices.

5.2.3. Results

Resulting estimates of customer generation savings (just the direct value of buying less quantity, not the price impact) are shown for representative years 2010 and 2013 in Tables 5.3 and 5.4, respectively. These tables also show the key elements of the calculation that was described in Section 5.2.2. (Note that the peak load and total load estimates are taken from the normalized load data used in the *Brattle*-PJM-MADRI study, and they are not escalated to account for load growth).

Table 5.3. Estimated Generation Savings in 2010

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	758,523	758,523	758,523	748,357	748,357	748,357
Jurisdictional Reduction (MW)	220	220	220	389	389	389
Reductions Not Offset by Supplier Response	103	220	220	228	389	389
Avoided Energy Costs (million 2007 $'s)	$3	$3	$4	$5	$5	$7

Table 5.4. Estimated Generation Savings in 2013

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	737,505	737,505	737,505	711,144	711,144	711,144
Jurisdictional Reduction (MW)	570	570	570	1,009	1,009	1,009
Reductions Not Offset by Supplier Response	101	350	570	119	620	1,009
Avoided Energy Costs (million 2007 $'s)	$7	$7	$11	$12	$12	$20

5.3. ANCILLARY SERVICES BENEFITS

Some DR could potentially provide spinning reserves or other ancillary services (A/S), by being able to turn off/down for 30 minutes at a moments' notice. Provision of A/S could benefit customers directly if rate structures allow customers to be paid the market price for ancillary services. Demand-side provision of A/S also lowers total resource costs by reducing the need for reserves from supply-side resources, the marginal value of which is given by the market price for spinning reserves.

However, A/S value is somewhat speculative because the PJM market does not currently permit small scale DR to participate in the ancillary markets. However, large DR currently provides small amounts of A/S in PJM and ISO-NE. It was assumed conservatively that AMI could eventually enable 100 MW of spinning reserves in all of PJM-E, amounting to 0.15 percent of peak load in all zones. The value of such reserves is estimated by multiplying a conservative quantity of spinning reserves by a historical average price of spinning reserves ($8.5/MWh for 2004-06)[33] and by the number of hours in a year.

6.0 SHORT-TERM ENERGY PRICE IMPACTS

6.1. THEORY

The energy market will clear at a lower price if load is reduced (by DSM) while supply offers remain constant. With reduced prices, consumer surplus increases and producer surplus decreases. The increase in consumer surplus is what is measured as a customer benefit.

[33] PJM website.

The concept can be illustrated with a supply and demand curve, shown in Figure 6.1. An illustrative supply curve is shown in blue; the demand curve is shown as a vertical line with no elasticity relative to spot prices, representing the fact that most customers are not exposed directly to changes in spot prices, so their short-term demand is unresponsive to spot prices (even if demand is responsive to changes in retail rates). Load reductions resulting from DSM is represented as a decrease in quantity demanded, from Q_1 to Q_2. This causes the spot price to drop from P_1 to P_2. The resulting increase in consumer surplus (and decrease in producer surplus) is given by area **bcde**, assuming that none of the load is hedged through forward contracts with generators. To the extent that load is hedged through pre-existing forward contracts that did not anticipate and incorporate the price effect of DSM, the price savings would be reduced, but only until the contracts expire and are replaced by new contracts that are based on refreshed market expectations.

Figure 6.1. Conceptual Diagram of Short-Term Energy Spot Price Impacts and Customer Benefits

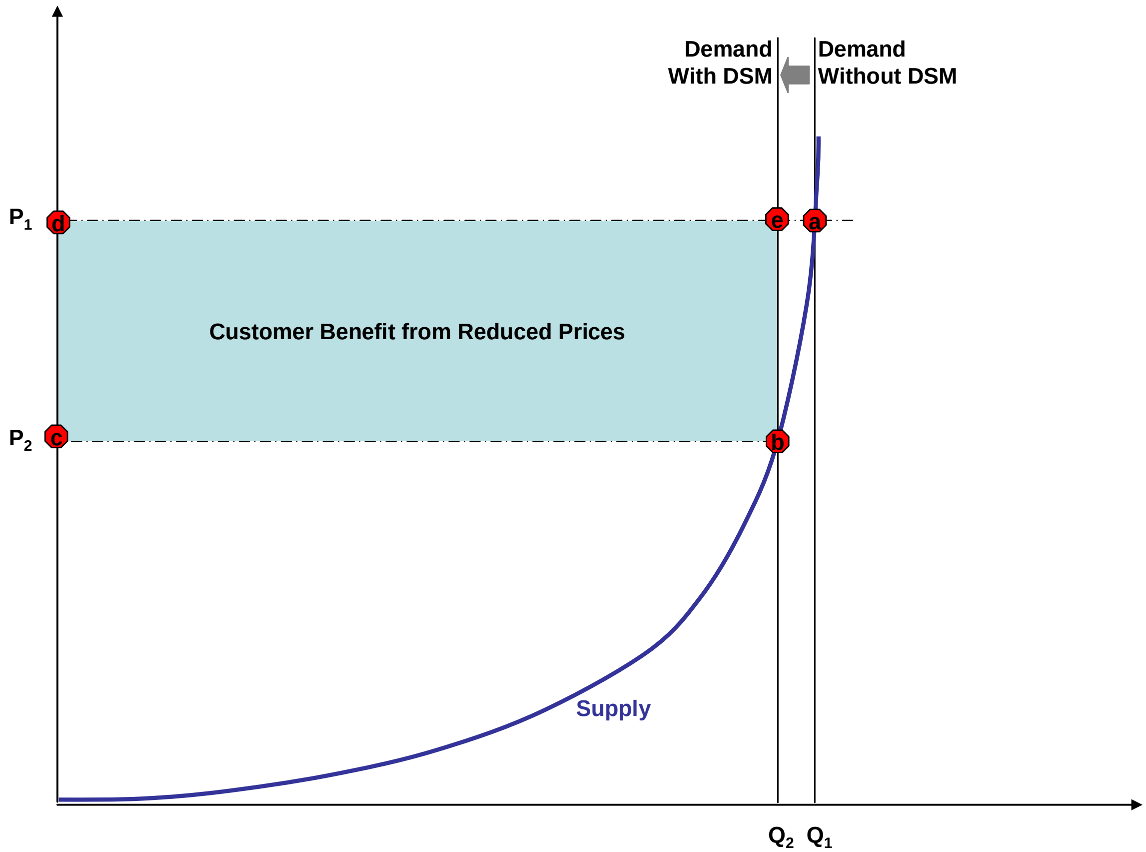


Figure 6.1 represents a short-run equilibrium in which supply remains static in spite of a reduction in demand and prices. In the long-run, the supply side can be expected to adjust to the prospect of depressed returns by accelerating retirements and/or delaying new construction, thus increasing energy prices and eventually offsetting some or all of the short-term price reduction caused by DSM. (DSM does not permanently lower market prices any more than building a power plant permanently lowers market prices). The key question is how long it takes suppliers

to react. Supplier reaction time should depend on the time required to detect change in fundamentals and market prices, to incorporate such information into planning decisions, and lead times required for changing construction schedules and gaining PJM approval for retiring plants, as well as regulatory and siting constraints. Because these factors are quite difficult to predict, we have constructed three scenarios in which the long-term is 1 year, 3 years, and up to 5 years, as described in Section 3.

6.2. METHODOLOGY

Short-term energy price reductions are estimated by adapting the price impacts from the top 60 hours in the *Brattle*-PJM-MADRI study (January, 2007) to reflect the expected load reductions associated with PHI's programs. As before, the "benefit" is given by the product of the estimated price reduction and the residual load (to be discounted based on the fraction of load that is exposed to market prices, as discussed below). Benefits are partially offset by an associated reduction in the value of Financial Transmission Rights (FTRs) (about a 15 percent offset).

To the extent that PHI's load reductions differ from the load reductions simulated in the *Brattle*-PJM-MADRI study, price impacts were linearly extrapolated (e.g., assume that twice the MW of load reductions would lead to twice the price impact). This linear approach does not consider that the marginal price effect probably diminishes as load reductions increase; that effect could be quantified by performing new simulations tailored to PHI's programs.

As described in Section 3, benefits are estimated at the PHI zonal level (split across state lines where applicable), the state level, and the entire PJM-East region, assuming three alternative geographic scopes of load reductions: (1) each PHI jurisdiction in isolation; (2) all PHI jurisdictions in concert; and (3) the entire PJM-East region. Because these configurations differ from those analyzed in the *Brattle*-PJM-MADRI study, approximation and data manipulation was required in order to adapt the results, as follows:

- <u>For DSM implementation by each PHI jurisdiction in isolation, and all PHI jurisdictions in concert</u>: given the load reductions estimated for each PHI jurisdiction, price impacts are estimated using the results of the corresponding one-zone curtailment cases described in Table 5.5 of the *Brattle*-PJM-MADRI report. (PSEG was used as a proxy for Atlantic Electric because PSEG is the only zone in NJ for which load reductions were analyzed in the *Brattle*-PJM-MADRI study.) The effect of one PHI zone's load reductions on prices in another PHI zone was estimated using the cross-zone methodology described below.

- <u>For DSM implementation in the entire PJM-East region</u>: given the load reductions projected for each PHI jurisdiction, and assuming all other zones in PJM-East achieve a similar level of load reduction, the total price effect in each zone is estimated as a sum of the price effect resulting from local load reductions plus the cross-zone effect from load reductions in all other PJM-East zones. The price effect from local load reductions is

> estimated as described above for isolated implementation. The additional impact on each zone's energy prices from load reductions in all other PJM-East zones is estimated using the average price impact ($/MWh local price impact per MW of outside load reduction) resulting from the *Brattle*-PJM-MADRI study's one-zone curtailment cases in which the local zone of interest did NOT reduce its load. For example, the effect of PECO's load reductions on Pepco MD prices is based on the Pepco MD price impact observed in the PECO-only curtailment case in the *Brattle*-PJM-MADRI study (but the price impact is scaled using the ratio of PECO load reductions in the present study to that in the *Brattle*-PJM-MADRI study). Each zone's price impact from load reductions in zones that were not studied in the *Brattle*-PJM-MADRI study, such as Allegheny, PPL, etc., is assumed to be the average (on a $/MWh per MW basis) of the price impacts from the five zones that were studied (excluding the local zone, e.g., estimating the impact of PPL on Delmarva by averaging the effects from load reductions in PSEG, PECO, Delmarva, and BG&E but not from Delmarva).

The results presented in the body of this report are based on an average of the price impacts simulated in the Low Peak and High Peak cases in the *Brattle*-PJM-MADRI study, which represented six percent deviations from weather-normalized 2007/08 load. (The appendix provides the range in addition to the average). Using an average of the High Peak and Low Peak is appropriate because it partially captures the non-linear increase in prices (and price sensitivity to DR) as market conditions become tighter. The High Peak case is probably conservative because it uses supply bids that were calibrated to a normal period, without accounting for the likely decrease in unit efficiency and availability or the potential for more aggressive bidding that might occur under very high temperature conditions.[34]

Given the estimated reduction in prices in each zone, the customer benefit is calculated by multiplying the change in price by the amount of load exposed to market prices. Only a fraction of load is exposed to market prices. The remainder is assumed to be covered by pre-existing contracts. It is assumed that in any given year 50 percent of load-serving obligations are supplied by new contracts and 50 percent are supplied by pre-existing wholesale contracts, corresponding roughly to the rate at which wholesale contracts for standard offer service turn over in D.C., Delaware, Maryland and New Jersey. It is further assumed, conservatively, that pre-existing contracts were priced without anticipating the spot market impacts of newly-introduced DSM. Given this assumption, only half of load is affected by the 1-year-duration price impacts in the "Immediate Supplier Reaction" scenario. In the "Slower Supplier Reaction" in which price impacts persist for three years, 5/6th of the load is exposed. These assumptions result in discounted customer benefits relative to the *Brattle*-PJM-MADRI study – a 50 percent

[34] The present study relies on the one-zone curtailment cases in the *Brattle*-PJM-MADRI study, for which only weather-normalized conditions were simulated, unlike the five-zone curtailment cases for which high peak and low peak conditions were simulated in addition to weather-normalized conditions. For one-zone curtailment, high peak and low peak impacts were estimated based on the assumption that the ratios of price impacts under alternative market conditions to the price impacts under weather-normalized conditions would be the same as in the five-zone curtailment cases in the *Brattle*-PJM-MADRI study.

discount in the "Immediate Supplier Reaction" scenario and a 17 percent discount in the "Slower Supplier Reaction" scenario. There is no discount in the "Delayed Supplier Reaction" scenario in which price impacts last through 2013.

In the long term, energy price impacts are likely to be offset by suppliers' adjustments to their capacity construction and retirement plans. The timing of this effect varies among the scenarios described in Section 3: in the "Immediate Supplier Reaction" scenario, the short-term price impacts last for 1 year after the deployment of each increment of DSM; in the "Slower Supplier Reaction" scenario, the short-term energy price impacts last for three years. In the "Delayed Supplier Reaction" scenario, the short-term energy price impacts last through 2013, about 1-5 years, depending on the deployment schedule of each increment of DSM.

6.3. RESULTS

Resulting estimates of customer benefits from short-term energy price impacts are shown for representative years 2010 and 2013 in Tables 6.1 and 6.2, respectively. These tables also show the key elements of the calculation that was described in Section 6.2. (Note that the peak load and total load estimates are taken from the normalized load data used in the *Brattle*-PJM-MADRI study, and they are not escalated to account for load growth).

Table 6.1. Estimated Energy Price Impacts in 2010

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	758,523	758,523	758,523	748,357	748,357	748,357
Jurisdictional Reduction (MW)	220	220	220	389	389	389
Reductions Not Offset by Supplier Response	103	220	220	228	389	389
Average Price Impact ($/MWh)	$2.3	$4.9	$4.9	$5.8	$9.9	$9.9
Average Price Impact per MW of Load Reduction	$0.01	$0.02	$0.02	$0.01	$0.03	$0.03
Hours affected	60	60	60	60	60	60
Average Residual Load (MW)	12,642	12,642	12,642	12,473	12,473	12,473
Annualized % of Residual Load Exposed to Market	50%	83%	100%	50%	83%	100%
Benefit to Exposed Residual Load (million 2007 $'s)	$1.2	$2.6	$2.6	$3.1	$5.2	$5.2

Table 6.2. Estimated Energy Price Impacts in 2013

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	737,505	737,505	737,505	711,144	711,144	711,144
Jurisdictional Reduction (MW)	570	570	570	1,009	1,009	1,009
Reductions Not Offset by Supplier Response	101	350	570	119	620	1,009
Average Price Impact ($/MWh)	$2.4	$8.2	$13.4	$2.8	$14.6	$23.7
Average Price Impact per MW of Load Reduction	$0.004	$0.014	$0.023	$0.003	$0.014	$0.024
Hours affected	60	60	60	60	60	60
Average Residual Load (MW)	12,292	12,292	12,292	11,852	11,852	11,852
Annualized % of Residual Load Exposed to Market	50%	83%	100%	50%	83%	100%
Benefit to Exposed Residual Load (million 2007 $'s)	$1.4	$4.8	$7.8	$1.5	$8.0	$13.0

6.4. Real-Time Premium

The *Brattle*-PJM-MADRI study treated all load reductions as if they occurred in the day-ahead timeframe. However, any load reductions that might actually occur in response to real-time (RT) market conditions have more market price impact than load reductions that can only be called in response to day-ahead (DA) market conditions. This is because RT markets are more volatile, with prices spiking when market conditions become unexpectedly tight. Real-time DR can mitigate unexpectedly tight market conditions that offline generators cannot respond to quickly enough.

However, the real-time premium applies only to DR that truly occurs in response to RT market signals, not to amounts already anticipated on a day-ahead basis as part of day-ahead load forecasts or day-ahead price signals. CPP programs would not count as real-time DR if critical periods were designated on a day-ahead basis, as is typical. Only the direct load control programs could provide RT response.

For the real-time DR from direct load control, a value premium over day-ahead DR was estimated by scaling the simulated price difference in a given hour by the ratio of historical super-peak RT prices to super-peak DA prices, based on price-rank of that hour.[35] For example,

[35] This approach is somewhat crude because the price ratios do not capture the differences in price sensitivities to changes in demand in the real-time versus day-ahead markets.

if a given hour has the second highest price in the simulations from the *Brattle*-PJM-MADRI study, the ratio of the second highest actual RT price to the second highest actual DA price from the June-September 2005 historical period. This led to factors of approximately 1.15 to 1.3 for the 60 critical hours, which were applied to the direct load control portion of benefits. All of the energy price benefits presented in this report include these factors.

Separately, a potential additional real-time was estimated for a hypothetical case in which CPP is also a real-time program, with critical periods designated day-of. The method for estimating the associated additional value is the same as described above for direct load control, but with a larger number of megawatts. The results of this calculation are presented in tables as a potential additional real-time premium, but they are not included in the net present value calculations.

7.0 SHORT-TERM CAPACITY PRICE IMPACTS

7.1. THEORY

Capacity markets should clear at lower prices in a short-run market equilibrium in which DSM has been introduced but generation suppliers have not yet made countervailing adjustments to their investment and plant retirement decisions. With reduced prices, consumer surplus increases and producer surplus decreases. The associated increase in consumer surplus is what is considered the economic benefit to customers.

In the long-run, the supply side can be expected to adjust to the prospect of depressed returns by accelerating retirements, delaying new construction, and/or submitting higher bids into the capacity market, thus increasing capacity prices and eventually offsetting some or all of the short-term capacity price reduction caused by DSM (DSM does not permanently lower capacity prices any more than building a power plant). As already discussed in Section 6, the time horizon characterizing the “long term” depends primarily on the time it takes suppliers to retire plants early (if there are any plants that can be retired) and to delay new construction (if there are any new projects that can be delayed). This timing is what varies among the Supplier Reaction scenarios.

In the “Immediate Supplier Reaction” and “Slower Supplier Reaction” scenarios, the market is assumed to reach economic equilibrium by 2009. No matter what level of load and DSM-induced load reductions would be expected (and scheduled by PJM into the administratively-determined capacity demand curve), suppliers would offer new capacity at Net CONE. The 3-year forward capacity prices would clear at Net CONE, and just the right amount of capacity would be built. By construction of these equilibrium scenarios, DSM would have no impact on capacity prices.

However, in the “Delayed Supplier Reaction” scenario, the market is assumed to be deficient in capacity and not in equilibrium until 2014. Under scarcity conditions, capacity market prices should be high, and DSM can play an important role in mitigating high prices and improving reliability. The methodology for estimating the capacity price impact in the “Delayed Supplier Reaction” scenario is described below.

7.2. METHODOLOGY

The methodology for simulating capacity prices by the intersection of capacity supply and demand curves case has already been described in Section 5.1.2. Whereas Section 5.1.2. projected capacity prices in order to evaluate the customer benefits from reducing the *quantity* of capacity they would be required to purchase, this section addresses the likely *change in capacity prices* due to DSM. Therefore, the key is to simulate the capacity markets with and without DSM and to compare the resulting clearing prices. As the construction of capacity supply and demand curves has already been described in Section 5.1.2 (regarding the projection of capacity prices without DSM), this section describes only how the capacity supply and demand curves (and the clearing price) change when PHI's proposed DSM plans are accounted for.

One key aspect of the RPM is the ability of DR to participate in the capacity market. While only a subset of load reductions under direct control (by the utility, other retail providers, curtailment service providers or the RTO) can participate as supply in capacity markets (e.g., smart thermostats), energy efficiency and the expected effect of CPP programs would also impact capacity prices by reducing the peak load forecast and thus the administratively determined demand for capacity, the Variable Resource Requirement (VRR) curve. Demand resources under direct load control are added to the capacity supply curve at a zero offer bid.

We estimated capacity prices for 2010/11 and 2013/14 delivery years with reduced peak loads (due to PHI's proposed DSM programs) by finding the intersection of the with-DSM supply and VRR curves in the two constrained Locational Delivery Areas (LDA) of PJM, Eastern MAAC LDA and Southwestern MAAC LDA, where all PHI zones are located. The resulting prices were then compared to the (higher) projected capacity prices without DSM.

Customer benefits from short-term capacity price impacts were estimated by multiplying the DSM-induced change in projected capacity prices by the residual UCAP requirement (i.e., with PHI's proposed programs in place).

7.3. RESULTS

For the "Delayed Supplier Reaction" scenario, market clearing capacity prices in the RPM were estimated for the Eastern and Southwestern MAAC LDAs for the delivery years 2010/11 and 2013/14, both with and without PHI-wide implementation of DSM. Figures 7.1, 7.2, 7.3, and 7.4 illustrate the impact of DSM load reductions on the capacity demand and supply curves, and the resulting changes in market clearing prices and capacity. Tables 7.1 and 7.2 below summarize the resulting benefits to customers in the "Delayed Supplier Reaction" scenario. (Recall that capacity prices are assumed to be insensitive to DSM in the "Immediate Supplier Reaction" and "Slower Supplier Reaction" scenarios).

Table 7.1 - Capacity Market Price Impact of PHI-Wide DSM Implementation in 2010/11
In the "Delayed Supplier Reaction" Scenario

		CPP-Voluntary		CPP-Default	
	Locational Delivery Area:	EMAAC	SWMAAC	EMAAC	SWMAAC
Load Reduction Available from DSM	MW	131	80	223	151
Capacity Market Price w/o DSM	$/MW-day	190	237	190	237
Capacity Market Price with DSM	$/MW-day	180	226	175	217
Change in Capacity Price	$/MW-day	-10	-11	-15	-20
Capacity Requirement	MW	39318	17098	39318	17098
Annual Customer Benefit	($ millions)	143	66	213	122

Table 7.2 - Capacity Market Price Impact of DSM in Delivery Year 2013/14
In the "Delayed Supplier Reaction" Scenario

		CPP-Voluntary		CPP-Default	
	Locational Delivery Area:	EMAAC	SWMAAC	EMAAC	SWMAAC
Load Reduction Available from DSM	MW	236	317	437	541
Capacity Market Price w/o DSM	$/MW-day	223	239	223	239
Capacity Market Price with DSM	$/MW-day	223	239	223	239
Change in Capacity Price	$/MW-day	0	0	0	0
Capacity Requirement	MW	41538	17893	41538	17893
Annual Customer Benefit	($ millions)	0	0	0	0

Figure 7.1. Simulated Capacity Auction for EMAAC in 2010
Delayed Supplier Reaction Scenario with CPP as the Default Rate

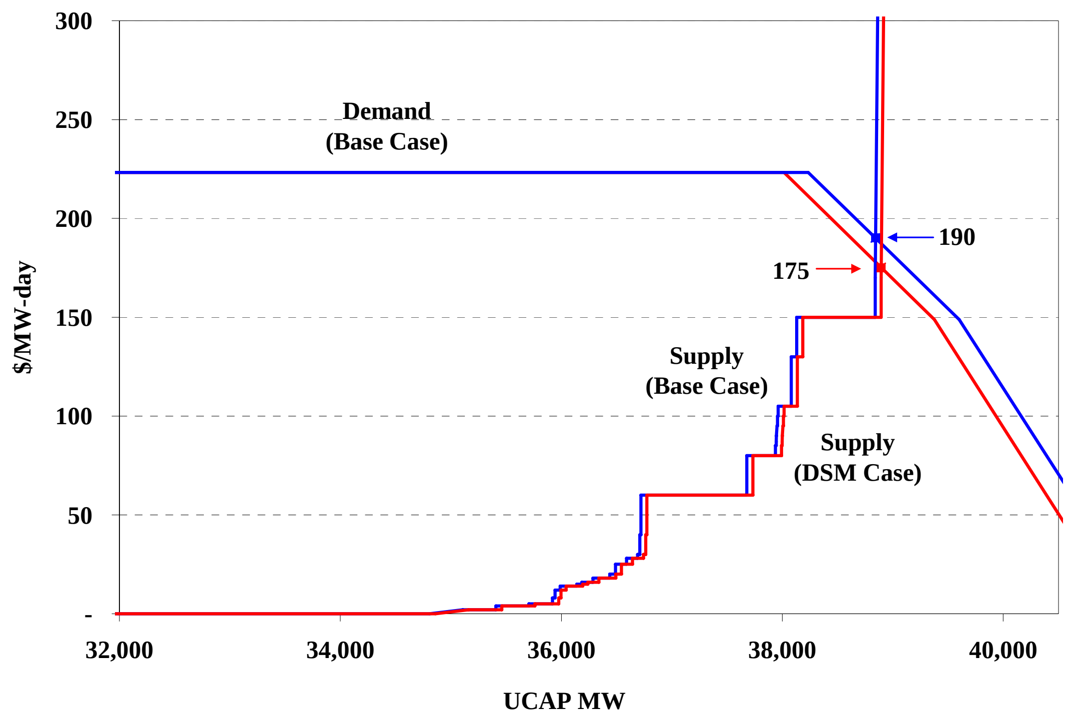


Figure 7.2. Simulated Capacity Auction for EMAAC in 2013
Delayed Supplier Reaction Scenario with CPP as the Default Rate

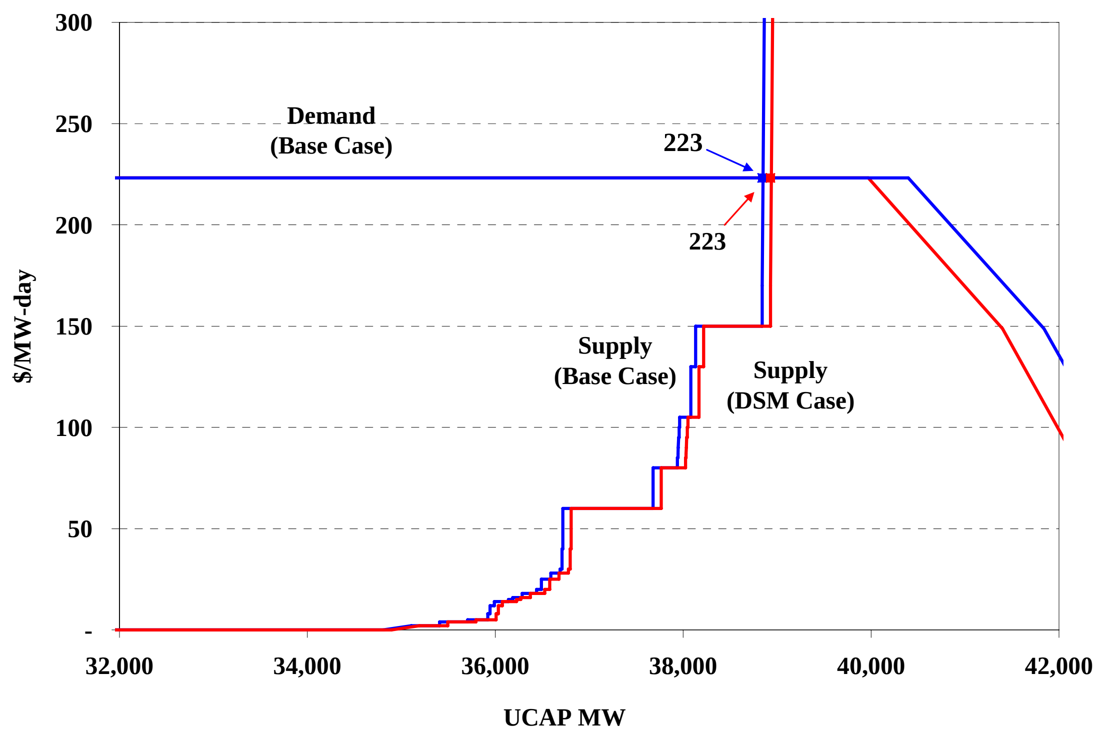


Figure 7.3. Simulated Capacity Auction for SWMAAC in 2010
Delayed Supplier Reaction Scenario with CPP as the Default Rate

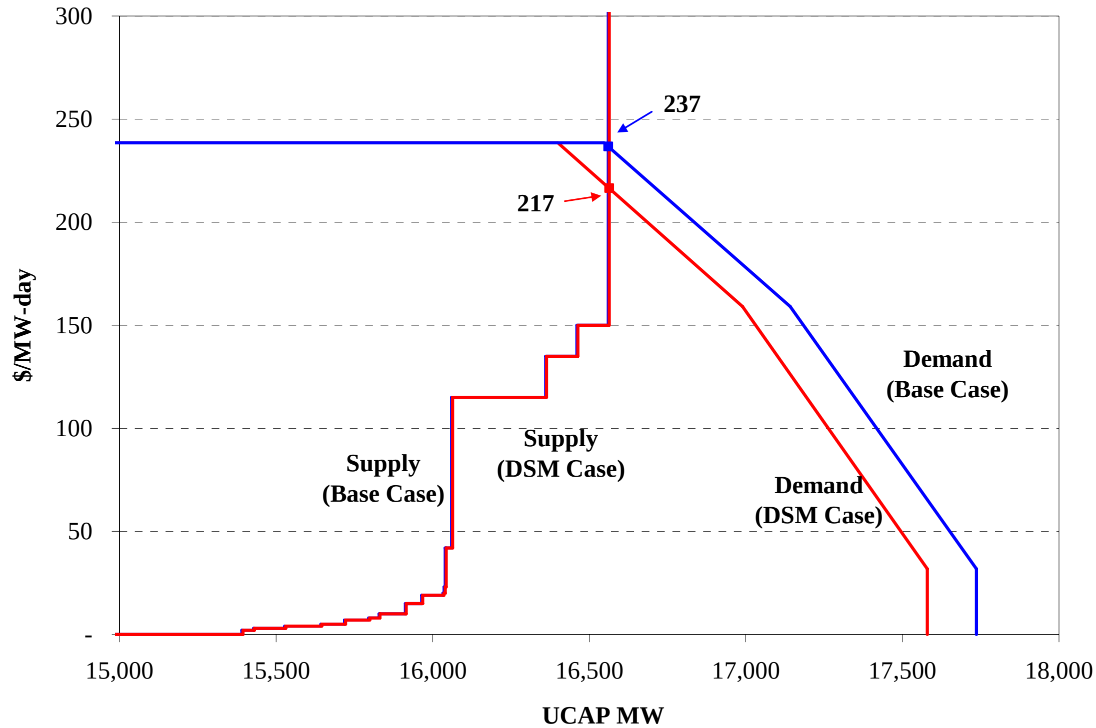
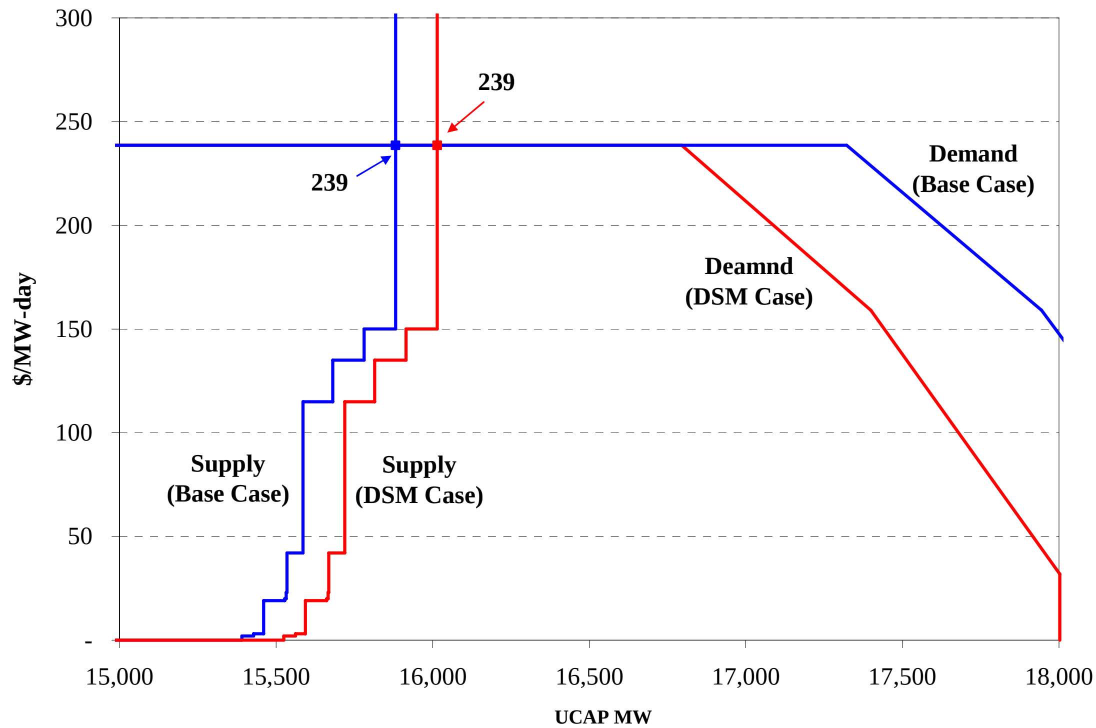


Figure 7.4. Simulated Capacity Auction for SWMAAC in 2013
Delayed Supplier Reaction Scenario with CPP as the Default Rate



8.0 OTHER BENEFITS THAT HAVE NOT BEEN QUANTIFIED

In addition to the resource cost savings and short-term market price impacts quantified in this study, reducing peak loads also creates customer benefits by: (1) improving reliability; (2) enhancing market competitiveness; (3) reducing rate volatility; (4) reducing transmission distribution losses; and (5) potentially obviating or delaying the need for investments in transmission and distribution. These categories of benefits have not been quantified either because the economic methodologies involved are not as well developed or standardized and/or because they could not be analyzed within the timeframe allowed for this analysis. These categories of benefits and related environmental issues are discussed qualitatively below.

8.1. RELIABILITY BENEFITS

DSM can reduce the probability and extent of rolling blackouts. With PHI's DSM programs projected to eliminate 1.2% of peak load in Eastern MAAC and 3.6% in Southwestern MAAC in 2013, the reliability benefit could be quite large. In the "Delayed Supply Response" scenario, PHI's DSM programs would increase reserve margins from 11.5% to 12.9% in EMAAC and from 5.8% to 9.9% in SWMAAC. In such a supply-inadequate scenario, DSM would prevent intolerably low reserve margins with likely blackouts and would allow the system to operate reliably. (It is difficult to believe that the utilities would not build capacity as a last resort if such low reserve margins were imminent and if DSM were not available).

Reliability also has economic value. Monetizing reliability benefits require estimating the effect of DSM on the expected loss of load, and then applying an economic value to each megawatt-hour of lost load. Several studies have quantified the value of lost load, finding $1,600 to $4,700 per megawatt-hour for residential customers and $7,000 to $50,000 for small C&I customers, so the economic value of incremental reliability can be quite high.[36]

The reliability value of DSM has not been captured in any of the capacity-related benefits quantified in this study. Although PJM's capacity market prices in the RPM are partly based on reliability factors, market-clearing prices are capped at 1.5 times the net cost of new entry (Net CONE). Therefore, under extremely tight market conditions, when the value of new capacity is very high from a reliability perspective, the reliability value of demand response load reductions would not be fully reflected in the market clearing capacity prices. For example, in our capacity market simulations, Southwestern MAAC LDA market clearing prices were at the price cap both with and without demand response, and hence no capacity market price effect was projected.

Table 8.1 below suggests that DSM could potentially have a very large reliability value, particularly in a capacity-deficient scenario, such as that represented by the "Delayed Supplier

[36] See *Value of Lost Load*,. Prepared by SAIC for Midwest ISO, May 2006; *Value of a Reliable Supply of Electricity* prepared by ICF for EEI, December 2005; *A Framework and Review of Customer Outage Costs*, prepared by LBL and Population Research Systems for DOE, November 2003; *Value of Service Reliability Study*, Prepared by Hagler Bailly for SCE, September 2000.

Response" scenario. In such a scenario, PHI's DSM programs would improve projected reserve margins from 5.8% to 9.9% Southwestern MAAC in 2013.

Table 8.1. Projected Reserve Margins in the Eastern and Southwestern LDAs

	SWMAAC LDA		EMAAC LDA	
	2010	**2013**	**2010**	**2013**
Internal Supply (UCAP MW) [1]	16,561	15,983	39,309	39,309
Coincident Peak Load (MW)[2]	14,487	15,161	33,579	35,474
LDA Reliability Requirement[3]	17,098	17,893	39,318	41,538
DR Load Reduction (MW)[4]	151	541	223	437
Pool-wide Avg EFORd[5]	6.13%	6.13%	6.13%	6.13%
Target Reserve Margin[6]	18.0%	18.0%	17.1%	17.1%
Existing Capacity	15,899	15,899	37,113	37,113
Assumed Cumulative Retirements	44	218	767	767
Assumed Cumulative Capacity Additions	13	13	304	304
Projected Reserve Margin (%, in UCAP terms)				
Base Case	14.3%	5.4%	17.1%	10.8%
DR Case	15.5%	9.3%	17.8%	12.2%
Projected Reserve Margin (%, in ICAP terms)				
Base Case	**15.2%**	**5.8%**	**18.1%**	**11.5%**
DR Case	**16.5%**	**9.9%**	**18.9%**	**12.9%**

[1] Based on aggregate supply in 2007/2008 Base Residual Auction (BRA). In future years, new capacity under construction construction was added, and units scheduled for retirement removed from supply. No generic capacity additions were assumed.
[2] Source of 2010 peak load: PJM Load Forecast Report, January 2007. Values for 2013 were derived by assuming an annual load growth equal to the growth rate in 2010.
[3] Based on RPM parameters published for the 2009/2010 delivery year. In subsequent years, reliability requirement is assumed to increase at the rate of coincident peak load growth.
[4] Cumulative load reductions from DSM, adjusted for differences in peak load coincidence.
[5] Based on RPM parameters published for the 2009/2010 BRA.
[6] Derived from the ratio of the reliability requirement and the coincident peak load forecast.

8.2. MARKET COMPETITIVENESS BENEFITS

During high-load periods, electricity markets suffer from structural problems that increase the incentive and ability for generators to exercise market power. Market power is exacerbated if most customers are not enrolled in DR programs, so they have no incentive to reduce even their lowest-value consumption when spot prices spike to $1,000 per megawatt-hour, leading to a demand curve that is almost completely inelastic. PHI's proposed DR programs would increase the elasticity of demand and thereby increase the competitiveness of the market. Simple game-theoretic models suggest that doubling the elasticity of demand – not an overly-ambitious goal, given the nascence of DR programs – would enhance competitiveness as effectively as a 50% reduction in market concentration.

Market competitiveness affects market prices for energy and capacity, even with PJM's market power mitigation measures in effect. PJM's market power mitigation measures can not possibly eliminate all exercise of market power, nor does it attempt to. Like all RTOs' market power mitigation protocols, PJM's attempts to strike a balance between being mitigating market power effectively and being overly stringent. For example, PJM has an agreement with more than 50 new generators installed between 1999 and 2003 not to mitigate their bids at all (except for the $1000/MWh offer cap).

Although there are no well-developed or standardized approaches to quantifying the benefits of enhancing market competitiveness, it is possible to estimate the impact on structural measures of market concentration (e.g., HHI, Pivotal Supplier Index). Furthermore, there are various approaches for translating improvements in these structural measures into potential changes in market prices that have been used in some benefit-cost studies of new transmission. For example, the California ISO estimated competitiveness benefits amounting to 50% to 100% of energy cost benefits for the Devers-Palo Verde 2 and Path 26 Upgrade projects, with a very wide range (5% to 500%) depending on future market conditions.[37]

A recent study conducted by *The Brattle Group* analyzing the benefits of a new transmission line in Wisconsin found competitiveness benefits can range from very small to multiples of the production cost savings of the line, depending on (1) market concentration; (2) the nature of market power mitigation; (3) the fraction of load served by cost-of-service generation; and (4) the generation mix and load obligations of market-based suppliers. These findings suggest the competitiveness benefit of adding resources (whether through transmission or DSM) to the energy market could be large in a restructured market such as PJM where little to no load is served by cost-of service generation.

8.3. INSURANCE BENEFITS / REDUCING RATE VOLATILITY

Many customers are risk-averse and value rate stability, for example because they need to be able to forecast their costs accurately for budgeting purposes. Hence, there is value to reducing the price variance, not just reducing expected prices.

As recent history has demonstrated, retail electricity prices can fluctuate in response to spot prices (for customers on real-time pricing) or in response to expected wholesale prices (for other customers, e.g., those on standard offer service). To the extent that DSM reduces volatility in the spot market, it improves overall electricity price stability for at least some customers. DSM reduces volatility by preventing the market from becoming as tight during normal peaks in load. This mitigating effect is greatest under extreme conditions. Even though this study presents a range of benefits, reflecting a range of market conditions, it does not account for the fact that the greatest benefits occur when rates are highest, when rate relief would be the most valuable. Moreover, there are many possible events that have not been considered in this analysis that could add disproportionately to the overall probability-weighted value of load reductions. Such events include the coincident outages of major generators and transmission lines or an extreme heat wave occurring in shoulder months when many generators are on maintenance. The value of DSM could potentially be quantified more completely by simulating such extreme, low-probability events. The associated reduction in variance could also be valued based on some measure of customer willingness-to-pay to reduce volatility.

[37] *Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2),* CAISO, February 24, 2005.

8.4. TRANSMISSION AND DISTRIBUTION LOSS BENEFITS

Reducing consumption generally reduces transmission and distribution losses. This is likely to add several percent to the savings that have been quantified, corresponding to the rate of marginal losses on the transmission and distribution systems.

8.5. TRANSMISSION AND DISTRIBUTION INVESTMENT BENEFITS

Reducing peak loads by 3% is comparable to two years of load growth on average and possibly much more in certain locations. In some circumstances, reducing peak loads could enable utilities to delay upgrading distribution transformers and other T&D equipment that is stressed by peak loads. This potential benefit is very location-specific and has not been analyzed in this study.

8.6. ENVIRONMENTAL CONSIDERATIONS

It is possible that demand reductions during critical peak periods achieve modest environmental benefits by reducing generation of the dirtiest plants in non-attainment areas on the hottest, smoggiest days. This effect is difficult to assess because it is very location-specific. In general, the environmental effects of load reductions during critical peak periods are likely to be quite small because the "critical peak" is typically only 60 hours, which is only 0.7% of the year. Reducing demand by 5% during so few hours reduces total generation by less than 0.07%, assuming 50% load factor. Emissions could decrease by an even smaller percentage or increase if responsive load shifts to other hours with different fuels on the margin, or if the customer provides itself with replacement energy using behind-the-meter distributed generation (DG).

Environmental benefits are much greater for energy efficiency than for DR because consumption and generation are reduced in all hours, not just critical peak hours.[38] However, it should be noted that AMI could also help to promote efficiency and conservation. AMI could provide customers with information on their energy usage patterns that enables them to manage and reduce their consumption more actively. For example, in-home displays of hourly usage profiles would enable customers to learn how much energy they are using when they are asleep or away, perhaps prompting them to turn off appliances or discard inefficient refrigerators.

8.7. NON-CRITICAL PERIODS

The study scope also excludes changes in consumption during the non-critical-peak hours because the energy price effects are less pronounced and capacity effects are non-existent in those periods. However, the efficiency component of PHI's proposed DR programs, and the additional efficiencies and conservation that are likely to result from AMI-based information,

[38] Efficiency is one of the most effective ways to achieve a lower level of emissions. However, under cap-and-trade regulation of emissions, efficiency measures must be accompanied by a tightening of emissions caps, or lese the total amount of emissions from all sources will remain unchanged.

can substantially reduce the quantity of generation. The potentially very large value to customers and the potential environmental benefits have not been analyzed in this study.

9.0 NET PRESENT VALUE OF BENEFITS

All of the categories of benefits are calculated on an annual basis, and a net present value is computed using the after-tax weighted average cost of capital provided for the PHI companies. The applicable rates are: ACE NJ 6.69%, Delmarva DE 6.23%, Delmarva DE 7.03%, PEPCO DC 7.09%, PEPCO MD 7.17%. To discount the benefit to all Maryland consumers, a load-weighted average of Delmarva MD and PEPCO MD rates is used (7.1%). To discount the benefit to all New Jersey consumers, the same rate was used as for ACE NJ. To discount the benefit to all consumers in PHI zones, as well as to all consumers in PJM-East, a load-weighted average rate of 6.85% was used.

The net present value of benefits for each scenario and for each combination of implementation area and beneficiary area, as described in Section 3, is tabulated below.

Table 9.1. NPV of Benefits to Customers through 2029 *CPP Default Scenario* (million 2007 $'s)

DSM Implemented in:	ACE NJ			ACE NJ			DPL DE		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$114	$114	$125	$114	$114	$125	$87	$87	$98
Avoided Energy Costs	$27	$27	$30	$27	$27	$30	$21	$21	$23
Ancillary Services Benefit	$3	$3	$3	$3	$3	$3	$4	$4	$4
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.5	$1.8	$2.5	$3.1	$11.5	$15.9	$1.0	$4.5	$7.8
Potential Additional Real-Time Benefit	$0.2	$0.3	$0.3	$1.4	$2.2	$2.7	$0.6	$1.0	$1.3
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$17.4	$0.0	$0.0	$125.9	$0.0	$0.0	$18.2
AVERAGE QUANTIFIED BENEFIT **	$145	$146	$178	$147	$156	$300	$112	$116	$151
Low Peak	$131	$132	$162	$133	$138	$280	$102	$104	$136
High Peak	$158	$160	$194	$162	$173	$320	$123	$128	$166

* In the "Immediate" scenario, short-term price impacts last for 1 year. In the "Slower" scenario, short-term price impacts last for 3 years. In the "Delayed" scenario, suppliers do not build new capacity (beyond projects currently in the queue) and short-term price impacts last through 2013."
** Excludes potential additional real-time benefit and unquantified benefits.

DSM Implemented in:	DPL MD			DPL MD			PEPCO DC		
Benefits to Customers in:	DPL MD			All MD			PEPCO DC		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$47	$47	$53	$47	$47	$53	$92	$92	$103
Avoided Energy Costs	$11	$11	$13	$11	$11	$13	$22	$22	$25
Ancillary Services Benefit	$1	$1	$1	$1	$1	$1	$2	$2	$2
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.3	$1.2	$1.8	$0.7	$3.2	$4.9	$0.5	$2.1	$2.8
Potential Additional Real-Time Benefit	$0.2	$0.3	$0.3	$0.5	$0.9	$1.1	$0.2	$0.3	$0.4
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$3.7	$0.0	$0.0	$26.0	$0.0	$0.0	$15.6
AVERAGE QUANTIFIED BENEFIT **	$60	$61	$73	$60	$62	$98	$117	$118	$149
Low Peak	$54	$55	$66	$54	$56	$90	$106	$107	$136
High Peak	$65	$67	$80	$66	$69	$106	$128	$130	$162

DSM Implemented in:	PEPCO MD			PEPCO MD			All PHI		
Benefits to Customers in:	PEPCO MD			All MD			PHI		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$204	$204	$231	$206	$206	$233	$548	$548	$614
Avoided Energy Costs	$49	$49	$55	$49	$49	$56	$131	$131	$147
Ancillary Services Benefit	$5	$5	$5	$5	$5	$5	$16	$16	$16
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$2.9	$12.2	$16.6	$6.4	$27.1	$36.7	$5.4	$22.0	$31.7
Potential Additional Real-Time Benefit	$2.3	$3.8	$4.6	$5.0	$8.4	$10.0	$3.5	$5.8	$7.0
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$89.9	$0.0	$0.0	$90.2	$0.0	$0.0	$275.4
AVERAGE QUANTIFIED BENEFIT **	$261	$271	$398	$267	$288	$421	$700	$717	$1,084
Low Peak	$237	$243	$365	$241	$255	$381	$634	$644	$1,000
High Peak	$286	$299	$431	$293	$321	$461	$766	$789	$1,168

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$117	$117	$125	$117	$117	$125	$80	$80	$98
Avoided Energy Costs	$28	$28	$30	$28	$28	$30	$19	$19	$23
Ancillary Services Benefit	$3	$3	$3	$23	$23	$23	$4	$4	$4
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$10.4	$41.4	$58.8	$58.9	$236.0	$335.1	$5.8	$22.2	$31.0
Potential Additional Real-Time Benefit	$3.9	$6.6	$7.9	$30.7	$51.4	$62.0	$2.5	$4.3	$5.2
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$238.0	$0.0	$0.0	$1,723.7	$0.0	$0.0	$244.3
AVERAGE QUANTIFIED BENEFIT **	$158	$190	$455	$227	$404	$2,237	$108	$124	$400
Low Peak	$140	$157	$413	$192	$303	$2,098	$96	$105	$375
High Peak	$177	$222	$497	$263	$505	$2,376	$120	$144	$425

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	PEPCO DC			DPL MD			PEPCO MD		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$93	$93	$103	$44	$44	$53	$205	$205	$231
Avoided Energy Costs	$22	$22	$25	$11	$11	$13	$49	$49	$55
Ancillary Services Benefit	$2	$2	$2	$1	$1	$1	$5	$5	$5
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$5.4	$21.6	$30.7	$2.4	$9.4	$13.1	$13.5	$54.1	$76.8
Potential Additional Real-Time Benefit	$3.8	$6.4	$7.7	$1.1	$1.8	$2.2	$9.6	$16.0	$19.3
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$122.1	$0.0	$0.0	$95.1	$0.0	$0.0	$281.7
AVERAGE QUANTIFIED BENEFIT **	$123	$140	$283	$59	$66	$175	$273	$313	$650
Low Peak	$111	$121	$260	$52	$56	$163	$244	$270	$596
High Peak	$136	$158	$306	$65	$75	$187	$301	$357	$705

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	All MD			PHI			PJM East		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$250	$250	$286	$543	$543	$614	$2,838	$2,838	$3,054
Avoided Energy Costs	$60	$60	$68	$130	$130	$147	$680	$680	$732
Ancillary Services Benefit	$16	$16	$16	$16	$16	$16	$78	$78	$78
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$41.6	$165.8	$234.8	$37.1	$147.4	$208.5	$179.3	$715.7	$1,014.5
Potential Additional Real-Time Benefit	$27.8	$46.6	$56.3	$21.2	$35.4	$42.8	$93.3	$156.2	$188.6
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$951.5	$0.0	$0.0	$990.7	$0.0	$0.0	$3,604.8
AVERAGE QUANTIFIED BENEFIT **	$368	$493	$1,557	$725	$836	$1,976	$3,776	$4,313	$8,484
Low Peak	$325	$408	$1,445	$647	$713	$1,820	$3,381	$3,724	$7,763
High Peak	$412	$577	$1,669	$804	$958	$2,132	$4,171	$4,901	$9,206

Table 9.2. NPV of Benefits to Customers through 2029 *CPP Voluntary Scenario* (million 2007 $'s)

DSM Implemented in:	ACE NJ			ACE NJ			DPL DE		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$62	$62	$69	$62	$62	$69	$47	$47	$53
Avoided Energy Costs	$15	$15	$17	$15	$15	$17	$11	$11	$13
Avoided Ancillary Services Costs	$3	$3	$3	$3	$3	$3	$4	$4	$4
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.3	$1.1	$1.7	$1.7	$7.2	$10.9	$0.6	$2.5	$4.2
Potential Additional Real-Time Benefit	$0.1	$0.2	$0.2	$0.8	$1.3	$1.6	$0.3	$0.4	$0.5
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$14.2	$0.0	$0.0	$102.9	$0.0	$0.0	$9.9
AVERAGE QUANTIFIED BENEFIT **	$81	$82	$105	$82	$88	$203	$63	$65	$84
Low Peak	$74	$74	$97	$75	$78	$191	$57	$58	$76
High Peak	$88	$90	$114	$90	$98	$215	$69	$72	$92

* Supplier Reaction Scenario; Immediate: short-term price impacts last for 1 year; Slower response: short-term price impacts last for 3 years, Delayed response: there is no generic entry, and short-term price impacts last through 2013.
** Excludes potential additional real-time benefit and unquantified benefits.

DSM Implemented in:	DPL MD			DPL MD			PEPCO DC		
Benefits to Customers in:	DPL MD			All MD			PEPCO DC		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$25	$25	$28	$25	$25	$28	$62	$62	$70
Avoided Energy Costs	$6	$6	$7	$6	$6	$7	$15	$15	$17
Avoided Ancillary Services Costs	$1	$1	$1	$1	$1	$1	$2	$2	$2
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.1	$0.6	$1.0	$0.4	$1.7	$2.7	$0.4	$1.4	$2.0
Potential Additional Real-Time Benefit	$0.1	$0.1	$0.1	$0.2	$0.4	$0.5	$0.1	$0.1	$0.2
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$2.1	$0.0	$0.0	$14.9	$0.0	$0.0	$12.2
AVERAGE QUANTIFIED BENEFIT **	$33	$33	$40	$33	$34	$54	$80	$81	$104
Low Peak	$30	$30	$36	$30	$31	$50	$72	$73	$95
High Peak	$36	$37	$43	$36	$38	$58	$87	$89	$112

DSM Implemented in:	PEPCO MD			PEPCO MD			All PHI		
Benefits to Customers in:	**PEPCO MD**			**All MD**			**PHI**		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$109	$109	$121	$109	$109	$122	$309	$309	$345
Avoided Energy Costs	$26	$26	$29	$26	$26	$29	$74	$74	$83
Avoided Ancillary Services Costs	$5	$5	$5	$5	$5	$5	$16	$16	$16
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$1.7	$6.1	$8.3	$3.6	$13.4	$18.2	$2.9	$11.6	$17.3
Potential Additional Real-Time Benefit	$0.9	$1.6	$1.9	$2.0	$3.4	$4.1	$1.5	$2.5	$3.0
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$39.7	$0.0	$0.0	$39.9	$0.0	$0.0	$162.8
**AVERAGE QUANTIFIED BENEFIT ** **	$141	$146	$203	$144	$154	$214	$401	$410	$623
Low Peak	$128	$131	$186	$130	$137	$194	$364	$369	$576
High Peak	$155	$161	$220	$158	$171	$235	$438	$451	$670

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	**ACE NJ**			**All NJ**			**DPL DE**		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$61	$61	$69	$61	$61	$69	$45	$45	$53
Avoided Energy Costs	$15	$15	$17	$15	$15	$17	$11	$11	$13
Avoided Ancillary Services Costs	$3	$3	$3	$24	$24	$24	$4	$4	$4
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$6.0	$24.0	$35.3	$34.9	$138.9	$204.4	$3.1	$12.2	$17.7
Potential Additional Real-Time Benefit	$2.0	$3.3	$4.0	$15.5	$25.9	$31.3	$1.2	$2.0	$2.4
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$144.8	$0.0	$0.0	$1,048.8	$0.0	$0.0	$148.2
**AVERAGE QUANTIFIED BENEFIT ** **	$85	$103	$270	$134	$238	$1,363	$62	$71	$235
Low Peak	$75	$85	$245	$114	$180	$1,279	$56	$61	$221
High Peak	$95	$121	$294	$154	$297	$1,447	$69	$82	$250

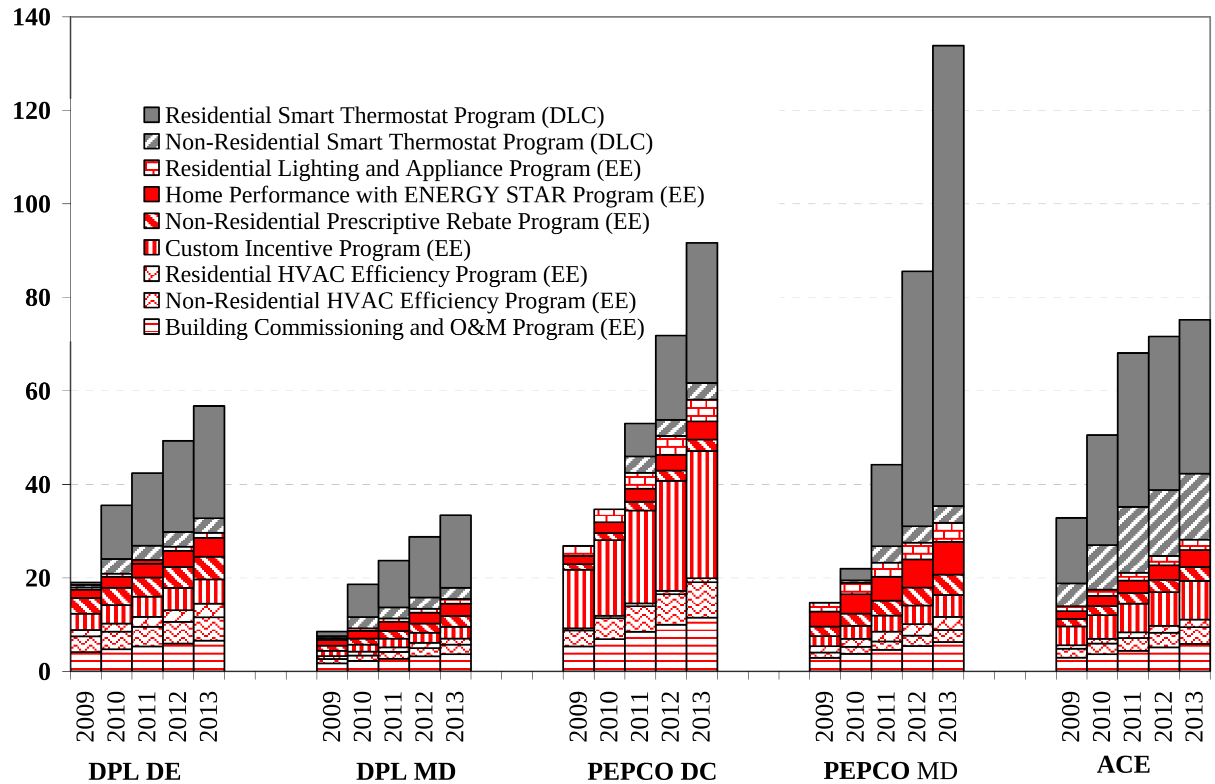
DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	**PEPCO DC**			**DPL MD**			**PEPCO MD**		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$63	$63	$70	$24	$24	$28	$113	$113	$121
Avoided Energy Costs	$15	$15	$17	$6	$6	$7	$27	$27	$29
Avoided Ancillary Services Costs	$2	$2	$2	$1	$1	$1	$5	$5	$5
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$3.1	$12.7	$18.7	$1.3	$5.2	$7.5	$7.9	$31.7	$46.9
Potential Additional Real-Time Benefit	$1.9	$3.2	$3.9	$0.5	$0.8	$1.0	$4.8	$8.1	$9.7
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$57.7	$0.0	$0.0	$58.0	$0.0	$0.0	$133.2
AVERAGE QUANTIFIED BENEFIT **	$83	$93	$166	$33	$37	$102	$154	$177	$336
Low Peak	$75	$81	$151	$29	$32	$95	$138	$153	$304
High Peak	$92	$105	$181	$36	$42	$109	$170	$202	$367

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	**All MD**			**PHI**			**PJM East**		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$138	$138	$150	$309	$309	$345	$1,578	$1,578	$1,697
Avoided Energy Costs	$33	$33	$36	$74	$74	$83	$378	$378	$407
Avoided Ancillary Services Costs	$16	$16	$16	$16	$16	$16	$79	$79	$79
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$24.2	$96.5	$142.2	$21.3	$84.9	$124.9	$104.3	$415.5	$611.7
Potential Additional Real-Time Benefit	$13.9	$23.2	$28.1	$10.5	$17.6	$21.3	$46.7	$78.0	$94.4
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$541.8	$0.0	$0.0	$547.7	$0.0	$0.0	$2,081.9
AVERAGE QUANTIFIED BENEFIT **	$212	$285	$887	$420	$484	$1,116	$2,139	$2,450	$4,876
Low Peak	$188	$236	$821	$376	$414	$1,025	$1,917	$2,116	$4,458
High Peak	$236	$333	$952	$465	$554	$1,206	$2,360	$2,784	$5,294

APPENDIX

Figure A.1 provides the load reductions that PHI expects from each of the components of its proposed DSM programs other than energy efficiency. (Note that load reductions from the internet-based platform programs have not been included in this figure.)

Figure A.1. Projected Peak Load Reductions from Energy Efficiency and Direct Load Control Reductions (MW) by Program Type, 2009-13



Tables A.1 and A.2 provide the net present value of each of PHI's proposed programs through 2024 and excluding the load reductions from energy efficiency to correlate with the Company's AMI business case. These tables are provided in order to be consistent with the scope of the business plans that PHI has prepared in support of its investments in advanced metering infrastructure (which will enable direct load control and dynamic pricing but not energy efficiency). Table A.1 corresponds to the scenarios in which dynamic pricing is the default rate structure, while Table A.2 corresponds to the scenarios in which enrollment in dynamic pricing is voluntary.

The benefits from AMI-enabled direct load control and dynamic pricing in Delmarva, DE shown in Tables A.1 and A.2 differ slightly from the preliminary estimates presented to the Delaware Public Service Commission on September 5, 2007 because of three revisions to the analysis. First, the "Delayed Supplier Reaction" scenario was modified to reflect construction of adequate supply and return to long-run equilibrium by 2014 instead of 2016, causing short-term market price impacts to last only through 2013 instead of 2015. Second, as described in Section 5.1.2, the capacity prices used to value avoided capacity costs in the "Delayed Supplier Reaction" scenario were projected based on supply conditions consistent with the scenario definition, instead of assuming capacity prices would be determined the net cost of new entry (Net CONE). Net CONE is assumed to set capacity prices only once the market is assumed to reach equilibrium. Third, in all scenarios, estimates of ancillary services benefits were replaced by a point estimate instead of a range.

Table A.1. NPV of Benefits to Customers through 2024 *CPP Default Scenario* (million 2007 $'s)

DSM Implemented in:	**ACE NJ**			**ACE NJ**			**DPL DE**		
Benefits to Customers in:	**ACE NJ**			**All NJ**			**DPL DE**		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$79	$79	$88	$79	$79	$88	$57	$57	$66
Avoided Energy Costs	$19	$19	$21	$19	$19	$21	$14	$14	$16
Ancillary Services Benefit	$2	$2	$2	$2	$2	$2	$3	$3	$3
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.4	$1.5	$2.0	$2.7	$9.7	$13.0	$0.8	$3.7	$6.2
Potential Additional Real-Time Benefit	$0.2	$0.3	$0.3	$1.4	$2.2	$2.7	$0.6	$1.0	$1.3
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$12.9	$0.0	$0.0	$93.3	$0.0	$0.0	$14.6
AVERAGE QUANTIFIED BENEFIT **	$100	$101	$126	$102	$109	$218	$74	$77	$105
Low Peak	$91.0	$91	$115	$92	$97	$203	$67	$68	$94
High Peak	$110	$111	$138	$113	$122	$233	$81	$85	$115

* In the "Immediate" scenario, short-term price impacts last for 1 year. In the "Slower" scenario, short-term price impacts last for 3 years. In the "Delayed" scenario, suppliers do not build new capacity (beyond projects currently in the queue) and short-term price impacts last through 2013."
** Excludes potential additional real-time benefit and unquantified benefits.

DSM Implemented in:	**DPL MD**			**DPL MD**			**PEPCO DC**		
Benefits to Customers in:	**DPL MD**			**All MD**			**PEPCO DC**		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$32	$32	$37	$32	$32	$37	$47	$47	$53
Avoided Energy Costs	$8	$8	$9	$8	$8	$9	$11	$11	$13
Ancillary Services Benefit	$1	$1	$1	$1	$1	$1	$1	$1	$1
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.2	$1.0	$1.5	$0.6	$2.7	$4.1	$0.3	$1.3	$1.5
Potential Additional Real-Time Benefit	$0.2	$0.3	$0.3	$0.5	$0.9	$1.1	$0.2	$0.3	$0.3
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$3.1	$0.0	$0.0	$21.5	$0.0	$0.0	$0.0
AVERAGE QUANTIFIED BENEFIT **	$41	$42	$52	$41	$43	$72	$60	$61	$69
Low Peak	$37	$38	$47	$37	$39	$66	$54	$55	$62
High Peak	$45	$46	$57	$45	$48	$78	$65	$67	$75

DSM Implemented in:	PEPCO MD			PEPCO MD			All PHI		
Benefits to Customers in:	PEPCO MD			All MD			PHI		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$152	$152	$176	$153	$153	$177	$369	$369	$423
Avoided Energy Costs	$36	$36	$42	$37	$37	$42	$89	$89	$101
Ancillary Services Benefit	$4	$4	$4	$4	$4	$4	$11	$11	$11
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$2.6	$11.2	$14.8	$5.8	$24.7	$32.8	$4.5	$18.2	$25.4
Potential Additional Real-Time Benefit	$2.3	$3.8	$4.6	$5.0	$8.4	$10.0	$3.5	$5.8	$7.0
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$77.2	$0.0	$0.0	$77.4	$0.0	$0.0	$208.3
AVERAGE QUANTIFIED BENEFIT **	$195	$203	$314	$199	$218	$334	$473	$487	$769
Low Peak	$176	$182	$288	$180	$192	$302	$428	$436	$709
High Peak	$213	$225	$340	$219	$244	$365	$518	$537	$828

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$80	$80	$87	$80	$80	$87	$54	$54	$68
Avoided Energy Costs	$19	$19	$21	$19	$19	$21	$13	$13	$16
Ancillary Services Benefit	$2	$2	$2	$16	$16	$16	$2	$2	$2
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$8.8	$34.8	$47.9	$50.1	$198.5	$272.9	$4.9	$18.5	$25.1
Potential Additional Real-Time Benefit	$3.9	$6.6	$7.9	$30.7	$51.4	$62.0	$2.5	$4.3	$5.2
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$191.3	$0.0	$0.0	$1,385.3	$0.0	$0.0	$196.5
AVERAGE QUANTIFIED BENEFIT **	$110	$136	$349	$165	$314	$1,782	$74	$88	$308
Low Peak	$97	$111	$317	$137	$231	$1,671	$66	$73	$289
High Peak	$124	$162	$381	$193	$396	$1,893	$83	$102	$327

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	PEPCO DC			DPL MD			PEPCO MD		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$64	$64	$73	$30	$30	$37	$141	$141	$164
Avoided Energy Costs	$15	$15	$17	$7	$7	$9	$34	$34	$39
Ancillary Services Benefit	$2	$2	$2	$1	$1	$1	$4	$4	$4
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$4.6	$18.2	$25.0	$2.1	$7.8	$10.6	$11.5	$45.5	$62.6
Potential Additional Real-Time Benefit	$3.8	$6.4	$7.7	$1.1	$1.8	$2.2	$9.6	$16.0	$19.3
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$93.5	$0.0	$0.0	$76.4	$0.0	$0.0	$215.8
AVERAGE QUANTIFIED BENEFIT **	$86	$99	$210	$41	$46	$134	$190	$224	$485
Low Peak	$77	$85	$193	$36	$39	$125	$170	$192	$444
High Peak	$95	$114	$227	$45	$53	$143	$211	$257	$527

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	All MD			PHI			PJM East		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$173	$173	$202	$373	$373	$431	$1,949	$1,949	$2,127
Avoided Energy Costs	$41	$41	$48	$89	$89	$103	$467	$467	$510
Ancillary Services Benefit	$11	$11	$11	$11	$11	$11	$53	$53	$53
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$35.3	$139.2	$191.1	$31.5	$123.7	$169.5	$152.2	$601.4	$825.9
Potential Additional Real-Time Benefit	$27.8	$46.6	$56.3	$21.2	$35.4	$42.8	$93.3	$156.2	$188.6
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$753.9	$0.0	$0.0	$780.9	$0.0	$0.0	$2,865.8
AVERAGE QUANTIFIED BENEFIT **	$261	$364	$1,207	$504	$596	$1,495	$2,621	$3,070	$6,382
Low Peak	$229	$298	$1,119	$448	$503	$1,377	$2,339	$2,627	$5,836
High Peak	$293	$431	$1,294	$560	$690	$1,614	$2,903	$3,514	$6,927

Table A.2. NPV of Benefits to Customers through 2024 *CPP Voluntary Scenario* (million 2007 $'s)

DSM Implemented in:	ACE NJ			ACE NJ			DPL DE		
Benefits to Customers in:	**ACE NJ**			**All NJ**			**DPL DE**		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$38	$38	$43	$38	$38	$43	$25	$25	$28
Avoided Energy Costs	$9	$9	$10	$9	$9	$10	$6	$6	$7
Avoided Ancillary Services Costs	$2	$2	$2	$2	$2	$2	$2	$2	$2
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.2	$0.8	$1.2	$1.3	$5.4	$7.8	$0.4	$1.6	$2.6
Potential Additional Real-Time Benefit	$0.1	$0.2	$0.2	$0.8	$1.3	$1.6	$0.3	$0.4	$0.5
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$9.7	$0.0	$0.0	$70.3	$0.0	$0.0	$5.9
AVERAGE QUANTIFIED BENEFIT **	$49	$50	$67	$50	$54	$134	$33	$34	$45
Low Peak	$45	$45	$61	$46	$48	$126	$30	$30	$41
High Peak	$54	$55	$72	$55	$61	$142	$36	$38	$50

* In the "Immediate" scenario, short-term price impacts last for 1 year. In the "Slower" scenario, short-term price impacts last for 3 years. In the "Delayed" scenario, suppliers do not build new capacity (beyond projects currently in the queue) and short-term price impacts last through 2013."
** Excludes potential additional real-time benefit and unquantified benefits.

DSM Implemented in:	DPL MD			DPL MD			PEPCO DC		
Benefits to Customers in:	**DPL MD**			**All MD**			**PEPCO DC**		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$14	$14	$16	$14	$14	$16	$23	$23	$26
Avoided Energy Costs	$3	$3	$4	$3	$3	$4	$6	$6	$6
Avoided Ancillary Services Costs	$1	$1	$1	$1	$1	$1	$1	$1	$1
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.1	$0.4	$0.7	$0.3	$1.2	$1.8	$0.2	$0.6	$0.7
Potential Additional Real-Time Benefit	$0.1	$0.1	$0.1	$0.2	$0.4	$0.5	$0.1	$0.1	$0.2
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$1.4	$0.0	$0.0	$9.7	$0.0	$0.0	$0.0
AVERAGE QUANTIFIED BENEFIT **	$18	$19	$23	$19	$19	$32	$29	$30	$34
Low Peak	$17	$17	$21	$17	$17	$30	$27	$27	$30
High Peak	$20	$21	$25	$20	$22	$35	$32	$33	$37

DSM Implemented in:	PEPCO MD			PEPCO MD			All PHI		
Benefits to Customers in:	PEPCO MD			All MD			PHI		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$73	$73	$83	$73	$73	$83	$174	$174	$198
Avoided Energy Costs	$17	$17	$20	$18	$18	$20	$42	$42	$47
Avoided Ancillary Services Costs	$3	$3	$3	$3	$3	$3	$9	$9	$9
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$1.4	$5.0	$6.4	$3.0	$11.0	$14.1	$2.0	$8.0	$11.2
Potential Additional Real-Time Benefit	$0.9	$1.6	$1.9	$2.0	$3.4	$4.1	$1.5	$2.4	$3.0
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$26.6	$0.0	$0.0	$26.7	$0.0	$0.0	$92.4
AVERAGE QUANTIFIED BENEFIT **	$95	$99	$139	$97	$105	$147	$227	$233	$358
Low Peak	$86	$88	$127	$88	$93	$133	$206	$209	$330
High Peak	$104	$109	$151	$107	$118	$162	$248	$256	$385

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$36	$36	$41	$36	$36	$41	$26	$26	$31
Avoided Energy Costs	$9	$9	$10	$9	$9	$10	$6	$6	$8
Avoided Ancillary Services Costs	$2	$2	$2	$14	$14	$14	$2	$2	$2
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$4.4	$17.1	$23.8	$25.4	$98.8	$137.8	$2.3	$8.6	$11.9
Potential Additional Real-Time Benefit	$2.0	$3.3	$4.0	$15.5	$26.0	$31.4	$1.2	$2.0	$2.5
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$90.1	$0.0	$0.0	$652.7	$0.0	$0.0	$92.3
AVERAGE QUANTIFIED BENEFIT **	$51	$63	$167	$83	$157	$855	$37	$43	$145
Low Peak	$45	$51	$151	$70	$116	$800	$33	$36	$136
High Peak	$57	$75	$183	$97	$198	$911	$41	$50	$154

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	PEPCO DC			DPL MD			PEPCO MD		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$37	$37	$42	$14	$14	$17	$67	$67	$73
Avoided Energy Costs	$9	$9	$10	$3	$3	$4	$16	$16	$17
Avoided Ancillary Services Costs	$1	$1	$1	$1	$1	$1	$3	$3	$3
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$2.3	$9.0	$12.7	$1.0	$3.6	$5.0	$5.8	$22.6	$31.7
Potential Additional Real-Time Benefit	$1.9	$3.2	$3.9	$0.5	$0.9	$1.0	$4.8	$8.0	$9.7
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$35.2	$0.0	$0.0	$36.1	$0.0	$0.0	$81.3
AVERAGE QUANTIFIED BENEFIT **	$50	$56	$101	$20	$22	$63	$92	$109	$206
Low Peak	$44	$49	$92	$17	$19	$59	$82	$93	$186
High Peak	$55	$64	$111	$22	$25	$67	$102	$124	$226

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	All MD			PHI			PJM East		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$82	$82	$90	$181	$181	$206	$926	$926	$1,008
Avoided Energy Costs	$20	$20	$22	$43	$43	$49	$222	$222	$242
Avoided Ancillary Services Costs	$10	$10	$10	$9	$9	$9	$45	$45	$45
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$17.6	$68.7	$96.0	$15.5	$60.4	$84.3	$76.0	$295.7	$412.5
Potential Additional Real-Time Benefit	$13.9	$23.2	$28.1	$10.5	$17.6	$21.3	$46.8	$78.1	$94.5
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$335.3	$0.0	$0.0	$338.5	$0.0	$0.0	$1,290.6
AVERAGE QUANTIFIED BENEFIT **	$128	$179	$553	$249	$294	$687	$1,269	$1,488	$2,998
Low Peak	$113	$147	$510	$222	$249	$629	$1,134	$1,274	$2,731
High Peak	$144	$212	$595	$277	$340	$745	$1,404	$1,703	$3,264

CERTIFICATION OF SERVICE

PHILIP J. PASSANANTE, of full age, certifies as follows:

1. I am an attorney at law of the State of New Jersey and an Assistant General Counsel to Atlantic City Electric Company, the Petitioner in the within matter, with which I am familiar.

2. I hereby certify that, on November 19, 2007, I caused an original and eleven (11) copies of the within Verified Petition and exhibits thereto to be sent by courier service to Kristi Izzo, Secretary, Board of Public Utilities, Two Gateway Center, Newark, New Jersey 07102.

3. I further certify that, on November 19, 2007, I caused a complete copy of the Verified Petition and exhibits thereto to be sent by Federal Express to each of the parties listed in the attached Service List.

4. I further and finally certify that the foregoing statements made by me are true. I am aware that, if any of the foregoing statements made by me are willfully false, I am subject to punishment.

Dated: November 19, 2007

By: P. Passanante

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In the Matter of Atlantic City Electric Company's "Blueprint for the Future," Establishing an Advanced Metering Infrastructure Program, Demand-Side Management Initiatives, Utility-Provided Demand Response Programs and Other Programs, and Requesting BPU Approval of Cost Recovery Mechanisms Related Thereto
BPU Docket No. ____________________

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