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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Senior Consultant*, 2006 to present.
Analysis and expert testimony regarding planning, market structure, ratemaking and contracting issues in the electricity and natural gas industries.

Charles River Associates (formerly Tabors Caramanis & Associates), Cambridge, MA.
Principal, 2004-2006.
Senior Consultant, 1998-2004.
Provided expert testimony and litigation support in several energy contract price arbitration proceedings, as well as in electric and gas utility ratemaking proceedings in Ontario, New York, Nova Scotia and New Jersey. Managed a major productivity improvement and planning project for two electric distribution companies within the Abu Dhabi Water and Electricity Authority. Analyzed a range of market structure and contracting issues in wholesale electricity markets.

Tellus Institute, Boston, MA.
Vice President and Director of Energy Group, 1997–1998.
Presented expert testimony on rates for unbundled retail services in restructured retail markets and analyzed the options for purchasing electricity and gas in those markets.
Manager of Natural Gas Program, 1986–1997.
Prepared testimony and reports on a range of gas industry issues including market structure, unbundled services, ratemaking, strategic planning, market analyses, and supply planning.

Nova Scotia Department of Mines and Energy, Halifax, Canada; 1981–1986
Member, Canada-Nova Scotia Offshore Oil and Gas Board, 1983–1986
Member of a federal-provincial board responsible for regulating petroleum industry exploration and development activity offshore Nova Scotia.

Assistant Deputy Minister of Energy 1983–1986
Responsible for analysis and implementation of provincial energy policies and programs, as well as for Energy Division budget and staff. Directed preparation of comprehensive energy plan emphasizing energy efficiency and use of provincial energy resources. Senior technical advisor on provincial team responsible for negotiating and implementing a federal/provincial fiscal, regulatory, and legislative regime to govern offshore oil and gas. Directed analyses of proposals to develop and market natural gas, coal, and tidal power resources. Also served as Director of Energy Resources (1982-1983) and Assistant to the Deputy Minister (1981-1982.

Nova Scotia Research Foundation, Dartmouth, Canada, Consultant, 1978–1981
Edited Nova Scotia's first comprehensive energy plan. Administered government-funded industrial energy conservation program—audits, feasibility studies, and investment grants.

Canadian Keyes Fibre, Hantsport, Canada, Project Engineer, 1975–1977

Imperial Group Limited, Bristol, England, Management Consultant, 1973–1975

EDUCATION

M.S., Technology and Policy (Energy), Massachusetts Institute of Technology, 1979.
Thesis: "An Assessment of Government Policies to Promote Investments in Energy Conserving Technologies"

B.Eng. Industrial Engineering (with Distinction), Dalhousie University, Canada, 1973

EXPERT TESTIMONY AND LITIGATION SUPPORT (1987 to present)

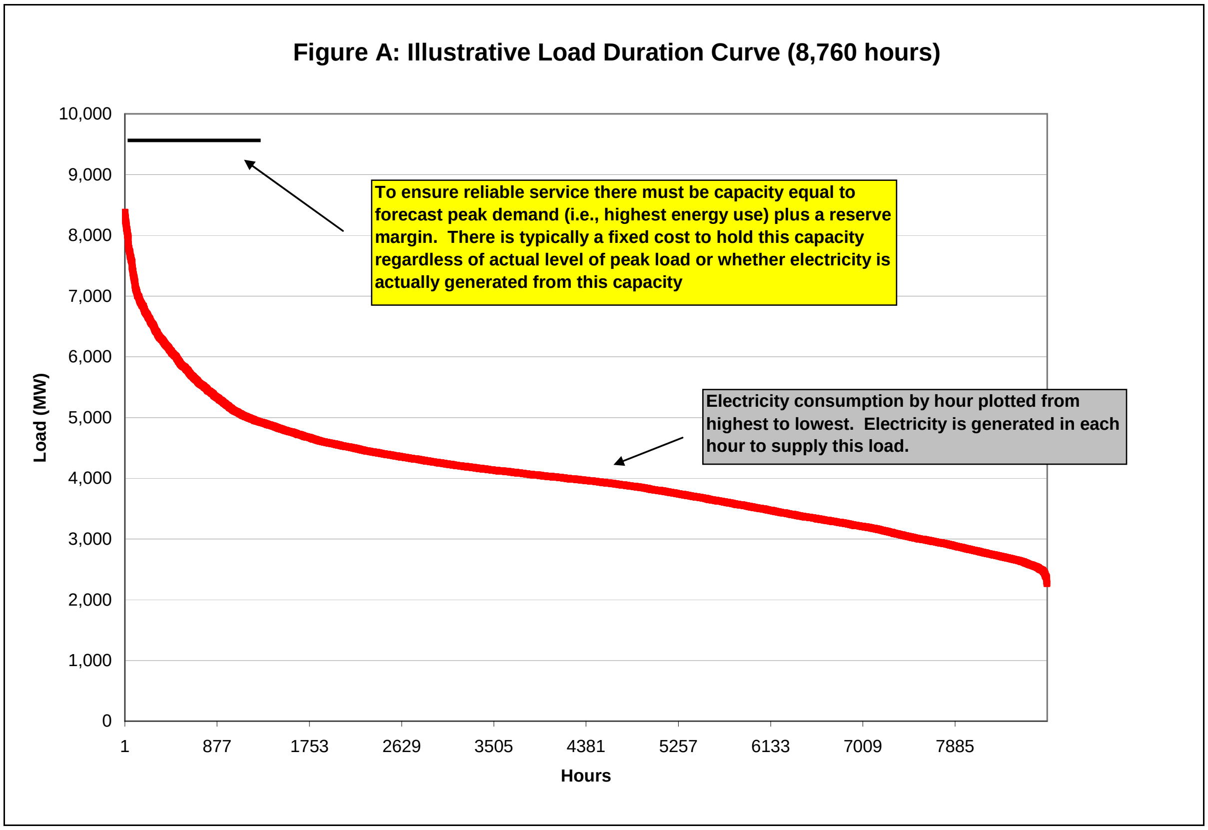
Provided expert testimony and/or litigation support on planning, market structure, ratemaking and gas supply/fuel procurement in the electric and gas industries in approximately 100 proceedings in over thirty jurisdictions in the United States and Canada. List of proceedings available upon request.

DEMAND RESPONSE (DR) PRODUCES MUCH LESS REDUCTION IN ANNUAL ENERGY CONSUMPTION AND ASSOCIATED CARBON DIOXIDE EMISSIONS THAN ENERGY EFFICIENCY (EE)

The deployment of smart meters will enable DR, including new price-driven DR by mass market customers. The anticipated reductions in peak load from that DR are projected to produce energy and environmental benefits. This exhibit explains why DR, including DR enabled by smart meters, will produce much less reduction in annual energy consumption and associated carbon dioxide emissions than EE.

1. Annual electricity supply costs and associated annual air emissions are a function of electricity consumption in all hours of the year

To appreciate the differences between DR and EE it is useful to begin with a review of the fundamental characteristics of annual electricity consumption and how those characteristics drive annual electricity supply costs and annual air emissions associated with annual electricity consumption. Those fundamental characteristics include the peak load, the annual load and the shape of that annual load. Those characteristics are illustrated in Figure A. This chart, referred to as a load duration curve, plots the total electric energy consumed by customers of a representative electric utility in each hour of a year. That consumption is plotted in decreasing quantity from the hour with highest use to the hour with lowest use.



The two major components of annual electricity supply costs are annual electric energy costs and annual electric capacity costs. Annual electric energy costs are driven by several key variables. The primary driver of those annual costs is the quantity of electric energy, in MWh, consumed in each hour of the year. In Figure A that consumption, plotted in the solid line which begins at over 8,000 MWh in critical peak hours and declines to approximately 2,500 MWh in off-peak hours. In retail markets whose supply costs are based upon market-based prices, the other important drivers are the type of unit that is on the margin, or sets the wholesale market price, in each hour such as natural gas units in peak hours and coal units in off-peak hours.

Annual electric capacity costs are driven by the quantity of electricity use during the hours of highest system-wide electricity use, or critical peak periods. (The critical peak periods of most utilities typically occurs in less than 100 hours each year. In the U.S. Northeast those critical peak periods typically occur during afternoons in July, August and September.) Electric industry planners determine the quantity of capacity needed in any given year to ensure reliable service by forecasting the quantity of retail peak load (MW) under extreme conditions and then adding allowances for line losses and for a target reserve margin. In Figure A the capacity required to ensure reliable service is approximately 9,600 MW, plotted in the solid horizontal line.

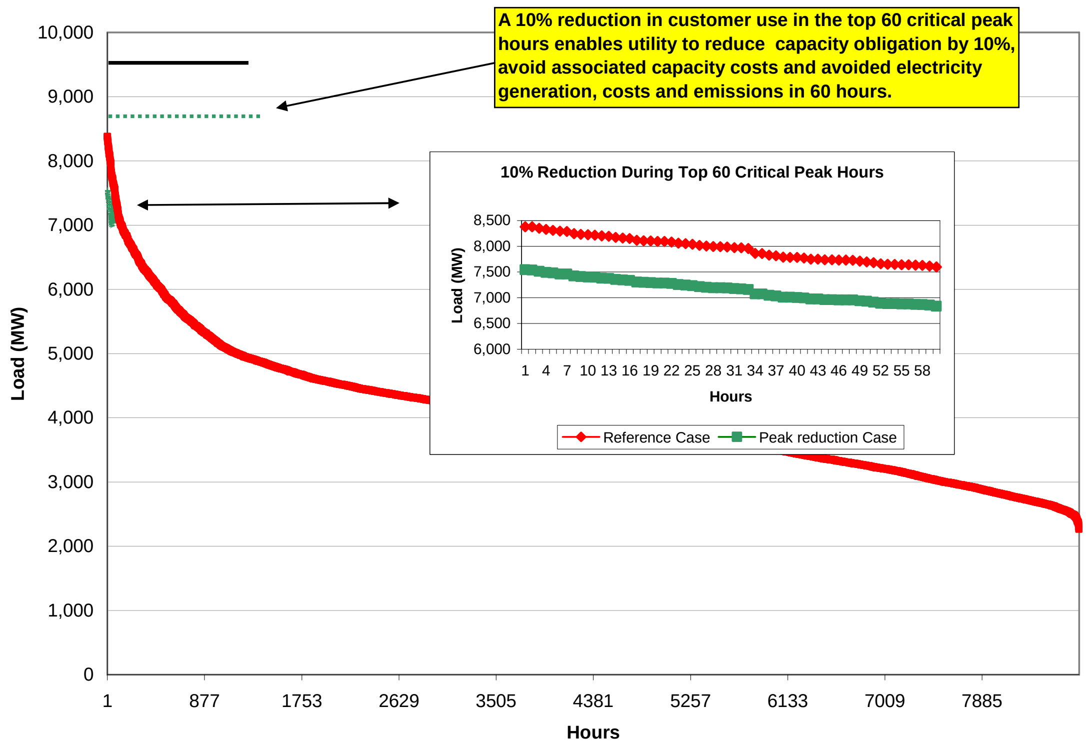
The annual air emissions associated with electricity consumption are driven by many of the same variables that drive annual electric energy costs. The primary driver of those emissions is the quantity of electric energy consumed in each hour of the year. Other important drivers are the quantity of electricity generated from each type of unit in each hour, e.g. nuclear, coal, natural gas and the air emissions per MWh generated by each of those units.

2. DR reduces load in critical peak hours whereas EE reduces load in most hours of the year, including critical peak hours

DR refers to the reduction of electricity use during the hours of highest system-wide electricity use, or critical peak hours. A common DR measure is to reduce central air conditioning ('cac') electricity use during critical peak periods by increasing the room temperature setting or by cycling the operation of the unit.

The impact of DR on the fundamental characteristics of the illustrative utility from Figure A is shown in Figure B. This chart illustrates the impact of DR that reduces load by 10 % in the top 60 critical peak hours

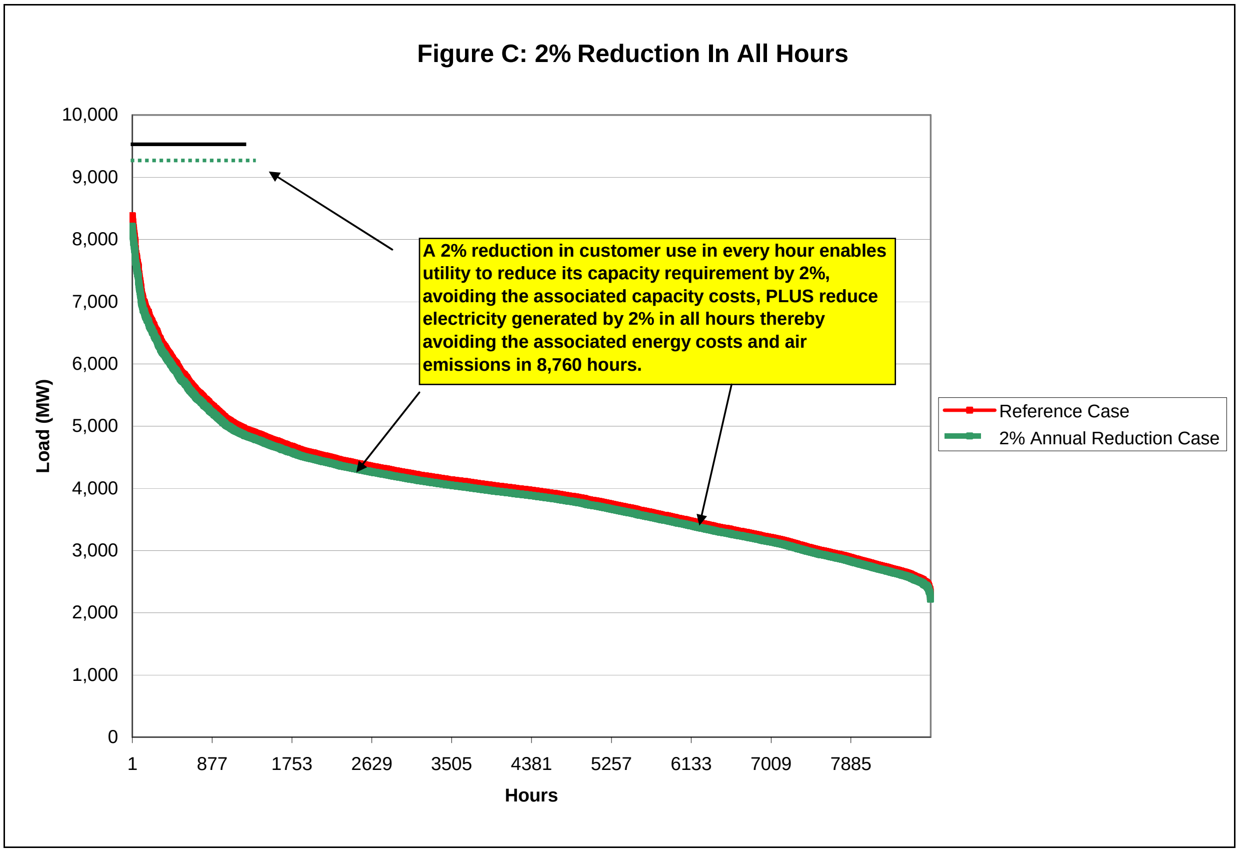
Figure B: 10% Reduction During Top 60 Critical Peak Hours



That illustrative reduction from DR would enable the utility to reduce the quantity of capacity by 10%, and to avoid the associated capacity costs. It would also enable the utility to reduce the quantity of energy it acquired in those 60 hours by 10%, and avoid the cost of that energy. Finally, the utility would avoid the air emissions associated with that 10% reduction in electricity use in those 60 hours.

EE refers to measures that reduce electricity use in all hours of the year affected by the EE measure. EE measures reduce electricity use during critical peak periods, like DR, as well as in all other hours of the year during which the application affected by the EE measure operates. For example, an EE measure such as insulating a home will reduce the air conditioning load of the home in all hours. That EE measure will reduce air conditioning electricity use during critical peak

The impact of EE on the fundamental characteristics of the illustrative utility from Figure A is shown in Figure C. This chart illustrates the impact of EE that reduces load by 2 % in all 8,760 hours of the year.

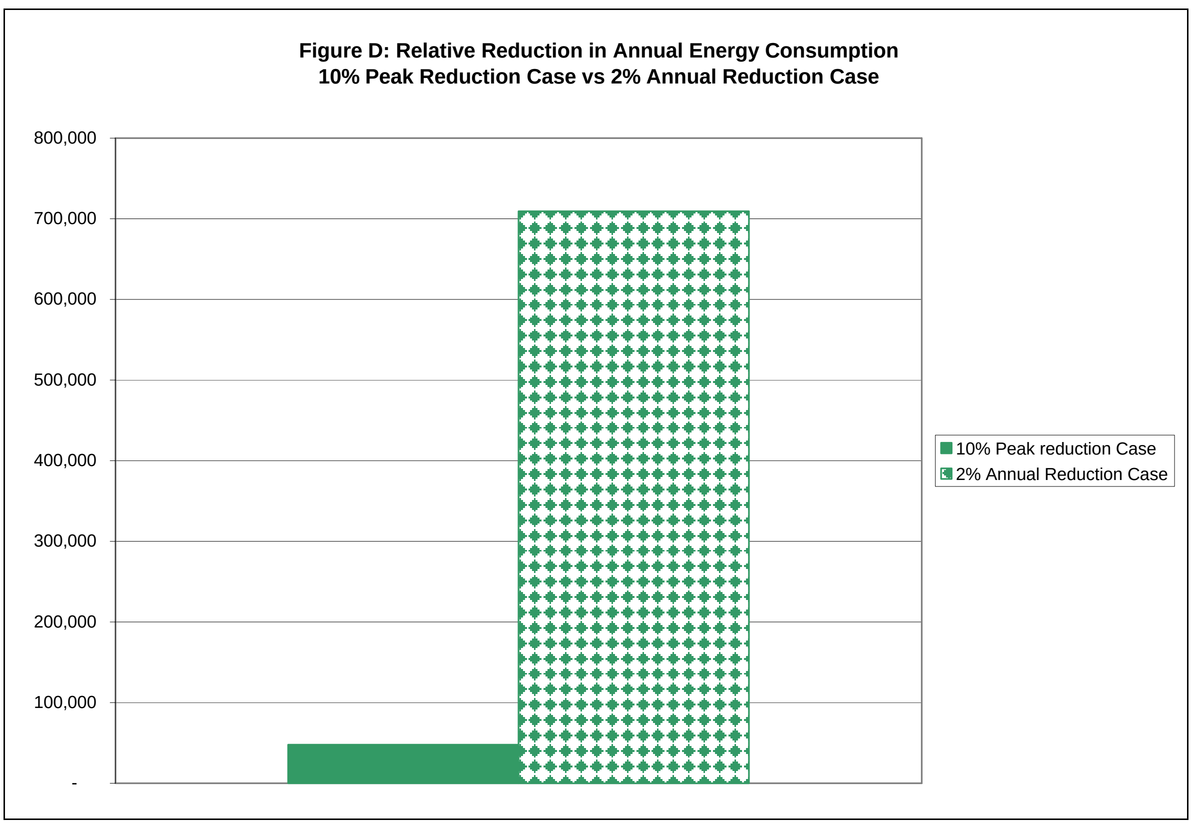


That illustrative reduction from EE would enable the utility to reduce the quantity of capacity by 2%, and to avoid the associated capacity costs. It would also enable the utility to reduce the quantity of energy it acquired in all 8,760 hours by 2%, and avoid the cost of that energy. Finally, the utility would avoid the air emissions associated with that 2% reduction in electricity use in those 8,760 hours.

3. DR Produces Much Less Reduction In Annual Energy Consumption And Associated Carbon Dioxide Emissions Than EE

Reductions in peak load from DR are valuable in terms of avoiding capacity costs and the costs of energy in critical peak periods. For example, a 10% reduction in peak load will certainly avoid more capacity costs, and peak hour energy costs, than a 1% reduction in peak load. However, DR produces much less reduction in annual energy consumption and associated carbon dioxide emissions than EE because DR reductions occur in less than 100 hours, or 1%, of the year. In contrast, EE causes reductions in both critical peak hours and in many additional hours of the year.

For example, the illustrations in Figures B and C indicate that, all else equal, an EE measure that reduces energy use by 2% in every hour would produce a reduction in annual energy consumption about 15 greater than a 10% reduction in critical peak hours from DR. Those relative reductions are presented in Figure D.



Some DR measures are designed to encourage customers to shift their consumption from peak hours, in which electric energy prices are higher, to off-peak hours in which electricity prices are lower. That load shifting may be valuable in terms of reducing the cost of energy, by acquiring the same annual quantity from lower cost sources of generation. However, since that shifting does not reduce the total quantity of electricity consumer, detailed analyses are required to determine whether it produces any material reduction in annual air emissions, such as carbon dioxide. In order to reduce annual emissions the average emissions from units on the margin in off-peak hours would have to less than emissions per MWh from the marginal units on on-peak hours.

**BEFORE THE
UNITED STATES SENATE**

COMMITTEE ON ENERGY AND NATURAL RESOURCES

TESTIMONY OF THE HONORABLE FREDERICK F. BUTLER COMMISSIONER, NEW JERSEY BOARD OF PUBLIC UTILITIES

**ON BEHALF OF THE
NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS**

ON

"Smart Grid"

March 3, 2009

**National Association of
Regulatory Utility Commissioners**
**1101 Vermont Ave, N.W., Suite 200
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Good morning Chairman Bingaman, Ranking Member Murkowski, and Members of the Committee:

My name is Frederick F. Butler, and I am a member of the New Jersey Board of Public Utilities (NJBPU). I also serve as President of the National Association of Regulatory Utility Commissioners (NARUC), on whose behalf I am testifying here today. I am honored to have the opportunity to appear before you this morning and offer a State perspective on "Smart Grid".

NARUC is a quasi-governmental, non-profit organization founded in 1889. Our membership includes the State public utility commissions serving all States and territories. NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation. Our members regulate the retail rates and services of electric, gas, water, and telephone utilities. We are obligated under the laws of our respective States to ensure the establishment and maintenance of such utility services as may be required by the public convenience and necessity and to ensure that such services are provided under rates and subject to terms and conditions of service that are just, reasonable, and non-discriminatory.

There's a worn-out cliché that goes something like this: Don't put the cart before the horse. In an industry as old as the electric utility sector, this saying aptly describes the situation we face in dealing with the modern Smart Grid and future demand growth.

As a State regulator in New Jersey and co-chair of a national board analyzing Smart Grid issues, I am absolutely convinced of the Smart Grid's potential to revolutionize how energy is delivered and consumed. I know the Smart Grid can change how utilities oversee their networks and improve reliability. I know that, in the end, consumers could have greater control over their usage and have the potential to lower their bills. I also know, however, that if we do not do this correctly, if we move too quickly and promise too much we can endanger our coming close to meeting any of those lofty aspirations.

That is why it is important to remember that old cliché and not put the cart before the horse. The benefits of the Smart Grid are obvious, and we must be sure that we move deliberately and in stages so that the costs of rolling out the necessary infrastructure are borne by those who will benefit. If we expect the horse—i.e. the consumers—to push the cart before it is ready, we many never get the Smart Grid off the ground. This means that we should not focus immediately on the end user and demand response; rather, we must start with the backbone—the transmission and distribution systems—while proceeding carefully to go inside consumers' homes.

Achieving the ultimate goal of reliable service at a fair and reasonable price is becoming harder and harder in this era of rising costs. There is a high probability that within the next three to ten years all electricity consumers will be facing higher costs because of rising fuel and commodity prices, as well as the initial sticker shock of federal and State initiatives to increase renewable generation and the anticipated costs associated with climate change legislation. These costs are and will continue to hit energy companies hard, and State regulators are faced with having to approve rate increases that a growing number of consumers may not be able to afford. Should the potentially substantial price tag of Smart Grid be suddenly thrust upon them, not withstanding the federal funding increase in the stimulus law, ratepayers will not be happy.

The utility industry is facing tremendous challenges, and we all need to welcome new technologies that could help this country become more efficient while bolstering the existing transmission grid. The Smart Grid has this potential, but only if embraced by utilities and, most importantly, consumers. Without getting the consumers on board, the Smart Grid may just be another good intention.

Before going too much further, it must be stated that our nation's energy woes will not be slain by a single silver bullet, but rather by what has been referred to as silver buckshot, a whole array of various and new revolutionary energy programs. This includes building some new transmission, encouraging renewable energy resources, promoting energy efficiency, resolving the nuclear-waste storage problem, and developing new technologies. The easiest and cheapest of this list is, of course, energy efficiency, but we must consider the role new technologies can play in helping us fix our current situation.

Here is where the Smart Grid comes into play. With the right investment and incentives, modernizing the nation's transmission system could revolutionize how and when we use electricity. If done correctly, utilities can streamline their operations and have more control over their networks. The more efficient we get, the less electricity will be lost on the transmission grid. Consumers, meanwhile, can reduce their usage across the board, and especially during peak times. This can actually lead to reduced electricity bills. From an operational, business, environmental and economic standpoint, the Smart Grid, if implemented properly, can be a major win-win.

But we do need to be careful. Right now, we are selling the Smart Grid as a means of empowering consumers to lower their usage and, correspondingly, their energy bills. While this may ultimately be the case, we must learn our lesson from the restructuring experience before heading down this path. The promise of restructuring was that consumers would save money by shopping for power. Nearly half the States introduced some kind of restructuring legislation in the mid- and late-1990s. Congress also considered mandating a national restructuring scheme during the late 1980s and early 1990s. In many States, rates were cut and/or frozen for a set number of years, so at the outset, restructuring seemed to be a success.

The 2000-2001 Western Energy Crisis prompted many to rethink this approach. Instead of lower prices, consumers saw their rates skyrocket as utilities were forced to buy electricity through the volatile spot-market costs which, we later found out, were being manipulated. Along the East Coast, starting in 2006, when rate caps expired in Maryland, ratepayers and politicians led a mutiny that nearly resulted in the demise of the State's Public Service Commission. Cooler heads prevailed and the massive rate increases were phased in over time, but many consumers still feel burned. Delaware and

Illinois have had similar experiences. We have not had these kinds of problems in New Jersey, but the sting in many States is being felt across the country.

The problem here was not restructuring per se, but it was the way it was sold to consumers. Instead of determining the best way to move forward deliberatively, we jumped right in, with the promise of lower rates to follow. Because of this approach, and because of the results, the concept of restructuring has taken a significant hit. Indeed, we put the cart before the horse.

We cannot make this same mistake with the Smart Grid if we want it to succeed. There is no doubt that the Smart Grid will bring consumers significant benefits. However, if we want to make the biggest impact, we should consider a different approach and concentrate first on the operational side while we educate consumers and deploy smart meters very strategically. Many utilities, engineers, and vendors have extolled the virtues of how an updated, modernized transmission system will give grid operators a much better view of their transmission and distribution network. New technologies can be installed on distribution poles and on the lines themselves to give advanced warning of a power surge. A modernized grid can help utilities lower costs by reducing the need for sending out trucks to read meters or restore power. Business operations can be streamlined, reliability can be improved, and money—real money—can be saved.

For instance, phasor measurement and backscatter sensors on the transmission grid, along with video sagometers and wireless mesh sensors, can use radio-frequency identification (RFID) technology to give utilities real-time information on the status of specific lines. These sensors can detect problems on the grid as they develop and that are relayed back to the utility for resolution before they escalate into a massive blackout. Instead of relying on costly and time-consuming manual visits from work crews, utilities will have up-to-date information on their system and can act accordingly. These reasons alone will make the Smart Grid a safe and worthwhile investment for utilities, whether or not end-users choose to get on board later.

From my perspective as a State regulator, it seems to make the most sense that if we're going to begin investing in a Smart Grid, we should start here. If we start with the backbone – if we update and improve the delivery system first – we will see the utility company side benefits of the Smart Grid. The question of who pays is important—and with consumers already challenged because of rising rates and the economic downturn, we must be careful before putting more on their plate. In this case, starting with the backbone means the initial investments would be paid for by the utilities themselves, as they will be the initial beneficiaries, and not immediately by ratepayers. While we all would like to see end users enjoy the benefits of Advanced Metering Infrastructure, the Smart Grid can still make an immediate and long-lasting improvement for the industry by making the delivery system more efficient. This alone will result in considerable savings and fewer outages. Meanwhile, advanced meters and the applications they enable can at the same time be deployed strategically in pilot and demonstration projects thus demonstrating the benefits to end-use customers. Moreover, these backbone investments are necessary at some point during the transition to the Smart Grid. So let's ready the cart to be pulled before asking the horse—or consumers—to pull it.

The second part of Smart Grid should be developed and implemented in an effort coordinated by State and local officials. In my experience as a Commissioner I have found that a key component for an initiative such as Smart Grid is public outreach. We should use some federal resources to explain to the consumers that a new Smart Grid program is worthwhile. Most State commissioners understand the benefits of Advanced Metering Infrastructure and time-of-use rates, but most consumers do not. Because these new programs will need new rate structures that will be disruptive to habits of paying energy that have been in place for over 120 years, we must proceed carefully to avoid public backlash. Time-of-use rates are being welcomed by some sectors of society and feared by others. States must be sure that consumers will embrace the technology and tolerate the initial investment. So far, this is only occurring in a few States. In California, for example, the Public Utilities Commission is committed to rolling out the Smart Grid to their consumers. The State has taken a number of steps laying out the initial foundation, including a decision in September 2008 approving a smart-metering program for Southern California Edison, one of the State's three investor-owned utilities.

Still, my colleague on the California PUC, Commissioner Dian Grueneich, said that despite the commission's conclusion on the benefits, key California consumer groups remain unconvinced that the Smart Grid will deliver. The advanced metering infrastructure deployment for Southern California Edison will cost about $1.63 billion, with estimated benefits ranging from $9 million and $304 million for consumers. Speaking in September 2008 at the Grid Week forum in Washington, D.C., Commissioner Grueneich said the PUC moved forward despite the strong opposition from some consumers. "Very significant costs have been authorized and put into rates," she said. "Our consumer groups are not comfortable" with this.

The concern that many of my colleagues are trying to resolve is that consumers are convinced that the Smart Grid will only raise their rates with no discernable benefits. In a high-priced environment, some or perhaps most consumers see advanced metering rollouts as just one more headache and budget buster and are particularly scared that utilities and vendors will keep raising rates as the technology changes.

California will be launching a major education, marketing, and outreach campaign next year. This will need as much support as possible from all parties so the program can succeed and perhaps reduce the sting on ratepayers. Once they see the benefits, they should also see how they can turn this into savings.

As this experience demonstrates, the way a Smart-Grid program is structured and rolled out is absolutely key to its success, and regulators and industry must be flexible to ensure that consumers will not feel inundated or overwhelmed. Depending on how a Smart-Grid program is structured and rolled out will be the key to its success, and Congress, regulators, and industry must be flexible to ensure that consumers will not feel inundated or overwhelmed. As a State regulator, here's how I think we should proceed.

A good place to look is at the work we're doing with the NARUC-Federal Energy Regulatory Commission (FERC) Smart Grid Collaborative, which I co-chair with FERC Commissioner Suedeen Kelly. As this is an issue that cuts across both wholesale and retail energy markets, the dialogues we are initiating through this process will help us all as we move forward. The Collaborative brings together a diverse group of State and federal regulators, consumer groups, and industry experts and allows us to talk in a public setting about these issues.

The Collaborative has met three times since its February 2008 inception, most recently at the NARUC Winter Committee Meetings last month. We have discussed issues such as cost allocation, specific technologies, interoperability, and pilot programs with consumers and industry executives who are promoting Smart-grid technologies.

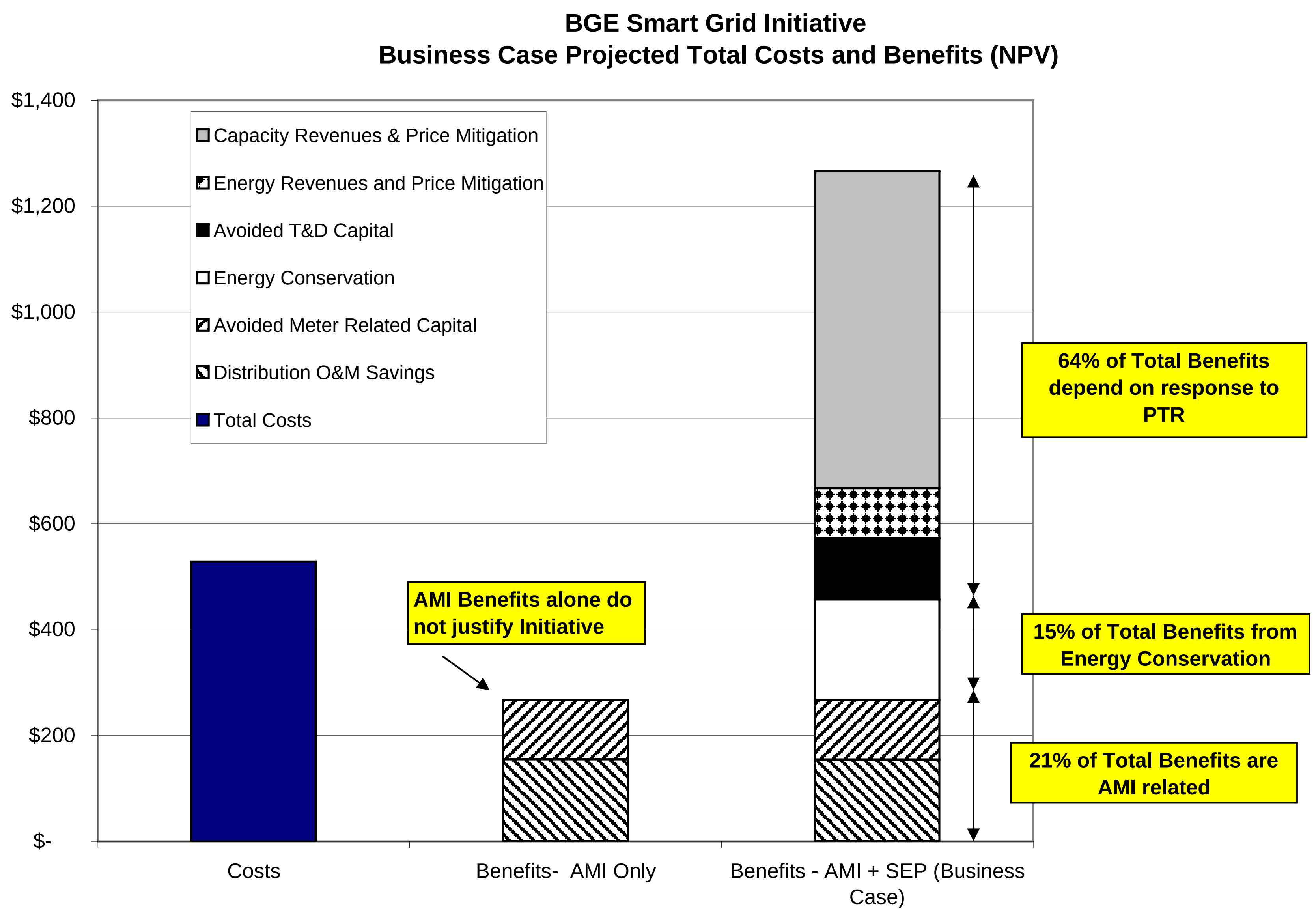
In my role as co-chair of this Collaborative, I have spent a considerable amount of time getting up to speed on the different technologies and pilot programs throughout the country. I am, as is the entire Smart-Grid industry, very interested in the pilot program in Boulder, Colorado, which is aiming to become the nation's first "Smart Grid City." I have discussed the many different pilots with my regulatory colleagues and am convinced that we must take a deliberate approach to introducing these new technologies to end-use consumers. As described above, consumers have yet to "buy into" the concept of the Smart Grid, and when they see any associated rate increases, they are more than likely not going to be pleased. Smart meters are expensive—right now we're talking about approximately $150 - $200 per meter—so we must be very careful in forcing anyone to upgrade if they are not willing. Pilot programs must be carefully structured in such a way that creates a "buzz" and excitement, not a ratepayer revolt.

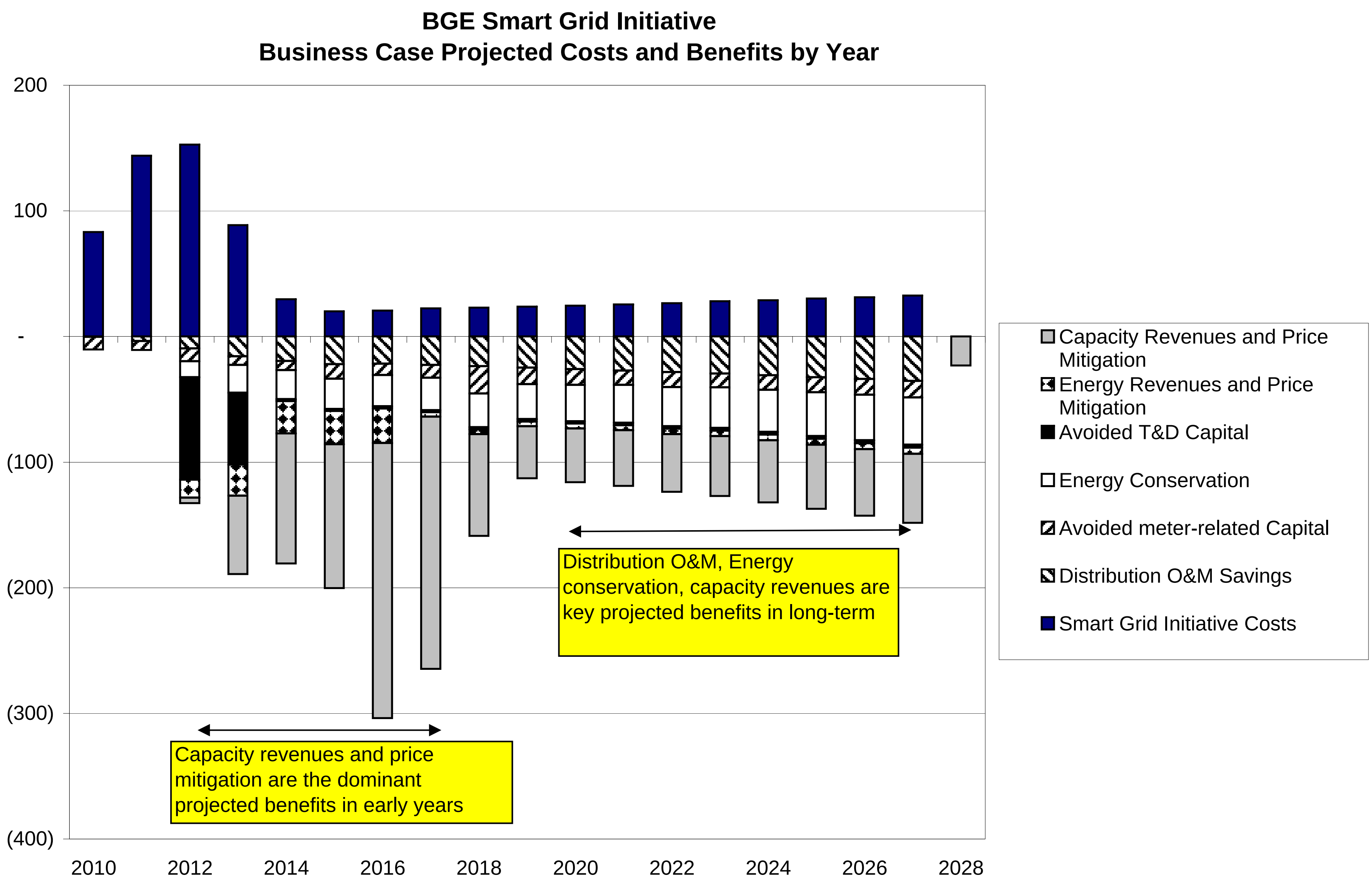
In addition, there should be large-scale "demonstration projects" that cover a larger geographic area. We are all watching the Boulder, Colorado effort and that project's success is instrumental to the future of the Smart Grid. These kinds of projects must cover a significant demographic area that reflects a microcosm of the country at large, including different incomes and education levels. While the pilot programs are useful, these larger projects will give us a glimpse as to how a larger pool of consumers will react to the Smart Grid. The project doesn't have to be huge, but it must be an accurate representation of the society.

This approach lets consumers take part by building interest and selling the product amongst themselves, rather than having Congress, utilities, or regulators do it for them. The consumers who want the meters will get the meters, and through word-of-mouth, others will find out how valuable this new system can be, and will be more willing to endure a slight rate increase to pay for it. What concerns me is that under some proposals, millions of people will get these smart meters whether they want them or not. They will be getting a rate increase and new gadgets that they do not know how to use installed in their homes. I am not sure if this will breed anything but hostility among a rate class that is already facing challenging economic times.

Smart Grid can be successful provided we have federal and State governments working in concert with one another as partners; not working in contrast to one another as adversaries. The challenge before us is great, the technology and potential benefits exciting. The federal government has resources that the States do not; the States have expertise in the development and implementation of programs that the federal government does not have. Therefore, this challenge calls for a true partnership between the States and FERC that we are already developing through the NARUC-FERC Smart Grid Collaborative.

We have to remember that the Smart Grid will only achieve its vast potential if consumers embrace it. While we can certainly see major improvements in efficiencies and reliability by upgrading the transmission and distribution backbone, we will not change consumers' habits and consumption if we are unable to convince them of its promise. I respectfully request that this Committee and this Senate recognize and respect our unique roles so that we can work towards a truly 21^{st} Century electricity delivery system.


BGE Smart Grid Initiative
Business Case Projected Total Costs and Benefits (NPV)
$1,400
$1,200
$1,000
$800
$600
$400
$200
$-
Capacity Revenues & Price Mitigation
Energy Revenues and Price Mitigation
Avoided T&D Capital
Energy Conservation
Avoided Meter Related Capital
Distribution O&M Savings
Total Costs
AMI Benefits alone do not justify Initiative
64% of Total Benefits depend on response to PTR
15% of Total Benefits from Energy Conservation
21% of Total Benefits are AMI related
Costs
Benefits- AMI Only
Benefits - AMI + SEP (Business Case)


BGE Smart Grid Initiative
Business Case Projected Costs and Benefits by Year
200
100
-
(100)
(200)
(300)
(400)
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
Capacity revenues and price mitigation are the dominant projected benefits in early years
Distribution O&M, Energy conservation, capacity revenues are key projected benefits in long-term
Capacity Revenues and Price Mitigation
Energy Revenues and Price Mitigation
Avoided T&D Capital
Energy Conservation
Avoided meter-related Capital
Distribution O&M Savings
Smart Grid Initiative Costs

MARKET FUNDAMENTALS AFFECTING FUTURE VALUE OF WHOLESALE GENERATING CAPACITY IN PJM

The prices for capacity in the wholesale market operated by PJM, referred to as the Reliability Pricing Model ('RPM'), set the value for wholesale generating capacity as well as for reductions in peak load. This exhibit discusses major demand and supply factors that will delay the need for new conventional capacity and thereby place downward pressure on the future prices for capacity in the RPM. The exhibit is based upon a high-level review of these factors prepared by Synapse Energy Economics as of September 2009.

1. PJM Interconnection

PJM Interconnection (PJM) is a regional transmission organization (RTO) which coordinates the movement of wholesale electricity in all or parts of thirteen states[1]. It also operates wholesale markets for electric energy, electric capacity as well as ancillary services.[2] The prices for energy vary by hour throughout the year[3] while the price of capacity varies by planning year[4]. The prices of both energy and capacity also vary by location or Load Delivery Area ('LDA'). Prices vary by location due to factors such as line losses and constraints on the quantity of transmission capacity available during periods of peak electricity consumption.

The utilities who participate in these markets, grouped according to their location or LDA as defined by PJM, are presented in Table 1 to this Exhibit.

2. Purpose and Operation of Wholesale Capacity Market (RPM)

A. Purpose of RPM

PJM is responsible for ensuring reliable service. One activity through which it accomplishes that goal is operation of the RPM. In operating the RPM PJM begins by

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[1] www.pjm.org.

[2] Synchronized Reserve and Regulation

[3] on-peak periods are weekdays, except NERC holidays, from hour ending 0800 until hour ending 2300

[4] PJM planning year is June 1 through May 31

setting the level of demand for which capacity and/or demand response (DR) resources must be available to ensure adequate service each year, referred to as a capacity obligation. PJM then acquires those resources through a series of auctions. Because of the lead time required to bring new conventional peaking capacity into service, PJM sets the capacity obligation three years in advance of the actual delivery or power year, also referred to as the planning year.

PJM sets the minimum capacity obligation for each delivery year equal to its projection of retail peak load (MW) under extreme conditions plus an allowance for line losses and a target reserve margin, referred to as Installed Reserve Margin ('IRM'). The target IRM is typically in the order of 115% of peak load. PJM sets this minimum capacity obligation for each LDA.

PJM acquires the resources through a series of auctions. The primary auction is the Base Residual Auction (BRA) which is held three years in advance. For example the BRA for the 2012 planning year was held in May 2009. PJM holds several subsequent, Interim Auctions between the BRA and the start of the delivery year. One of the major purposes of the RPM is to provide suppliers of existing capacity and DR sufficient compensation to assure their continued participation and, if new capacity is required, to provide prospective providers sufficient compensation to invest in that new capacity.[5]

The actual capacity obligation established for a delivery year is the quantity of capacity that clears in the RPM auction for that delivery year. The load serving entities ('LSEs')[6] in each LDA are obliged to control, and pay for, capacity based on their specific capacity obligation. The price for capacity established by the RPM auction for any given delivery year is the market value of capacity in that delivery year.

B. Establishment of Market Clearing Price in RPM

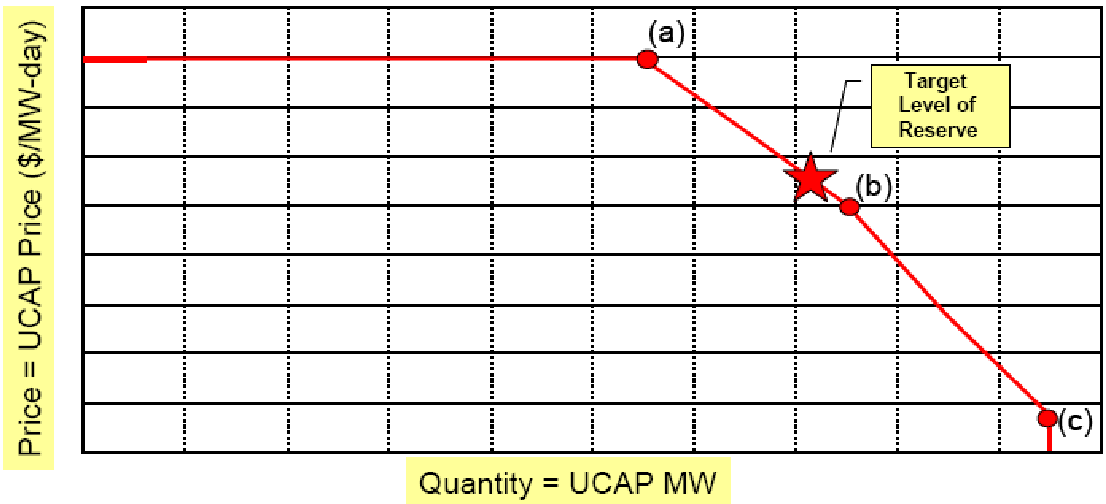
PJM sets the quantity of capacity to be acquired in a given year, and the market clearing price for that capacity, based on the intersection of the supply curve for that year and PJM's administratively determined demand curve. The supply curve reflects the quantity and price bids submitted by generators and demand resources in the BRA. PJM has

[5] PJM, "Reliability Pricing Model," http://pjm.com/markets-and-operations/rpm.aspx (downloaded September 24, 2009).
[6] LSEs provide electricity supply service to retail customers.

determined the demand curve, referred to as the Variable Resource Requirement ("VRR") curve, administratively.[7] These curves are plotted as price, on the y axis, versus quantity, on the x axis.

Figure 1 is an illustrative example of PJM's VRR curve.[8]

Figure 1



The administrative VRR curve consists of the following three key points:

- Point A is equal to a y axis value of 1.5 times the Net Cost of New Entry ('CONE') and an x axis quantity equal to 3% less than the target IRM;
- Point B is net CONE at the target IRM plus 1%; and
- Point C is 20% of net CONE at a supply 5% greater than the target Installed Reserve Margin.

PJM's current calculation of Net CONE is based on its assumption that the marginal source of new capacity is a gas-fired combustion turbine (CT). The value of net CONE is PJM's estimate of the cost and expected market revenues of a gas-fired CT. Net Cone is the difference between the cost of building and operating such a plant and the amount of energy and ancillary service revenue PJM estimates that it would receive under average

[7] Levitan & Associates for the Maryland Public Service Commission, "An Analysis of Resource and Policy Options for Maryland's Energy Future," December 1, 2008, section 2.2

[8] PJM Capacity Market Operations, Manual 18: PJM Capacity Market, Revision 7, August 18, 2009, Exhibit 1 (available at http://pjm.com/documents/~/media/documents/manuals/m18.ashx)

market conditions. In other words net CONE is an estimate of the compensation, in excess of energy and ancillary service revenues, that a developer of a gas-fired unit would require from the capacity market in order to bring it online. Thus the RPM is currently explicitly designed to provide a capacity price that would support new entry of a gas-fired CT, if and when new capacity is required.

As of September 2009, PJM has conducted six BRAs. The first three were transitional and hence not representative. In this analysis we focus on the most three auctions, for planning years 2010 through 2012 respectively. Table 2 shows the net CONE values set for each BRA. Table 3 shows the resource clearing prices in the six BRAs and Table 4 shows the market prices as a percent of net Cone each year.

A review of the three most recent auctions indicates that, except for DPL south, the market prices in all LDAs have, on average, cleared at prices below net CONE. For example, in MAAC, one of the constrained LDAs, net Cone in the past three auctions has averaged $160 per Mw-day. This amount is equivalent to $59 per kw-year.[9] In contrast, the market price in MAAC averaged $139 per MW-day ($51 per kw-yr). Some LDAs have experienced much lower average market prices. For example market prices in the APS LDA in western Pennsylvania averaged $100 per Mw-day or $36 per kw-year. Those prices were about 50% of net CONE for that LDA.

3. Market Fundamentals Expected To Place Downward Pressure on Future Prices for Capacity in RPM

The key assumptions underlying the current RPM approach are that peak load will grow, new capacity will have to be built to meet the new load and gas-fired CTs will be the least cost sources of that new capacity. All of those assumptions are open to question.

Several demand and supply factors are likely to combine to delay the need for new conventional peak capacity and thereby place downward pressure on the future prices for capacity in the RPM. Those market fundamentals are likely to result in market prices for capacity below current values of net CONE for a gas fired CT over the

[9] $162 per MW-day * 365 days per year * 1 MW per 1,000 kw

planning period. For example, the most recent two BRAs, for the 2011 and 2012 planning years, produced market prices about 60% to 65% of net CONE in most LDAs. Our review of market fundamentals indicates that future market prices could remain in this range, e.g. $110 to $133 per Mw-day ($40 to $46 per kw-yr) or lower rather than the $171 to $176 per Mw-day ($60 to $64 per kw-yr) suggested by net CONE .

A. No Guarantee That RPM Prices Will Approximate Net CONE of A Gas-Fired CT Indefinitely

PJM currently assumes that net CONE based upon a gas-fired CT is a realistic proxy for the marginal source and cost of new capacity. However, that net Cone is only a planning parameter in setting the VRR curve. Moreover, there is no guarantee that the RPM clearing price will approximate that particular net CONE over any given time period.

The RPM clearing price is likely to average a level equal to that particular net CONE over time only if certain key assumptions regarding the demand for and supply of, capacity in the wholesale market hold true. Those key assumptions, which are embedded in the computer model of RPM developed by its consultant, are as follows:

- The market is generally in equilibrium, meaning that essentially the same amount of compensation is required to entice all types of resources to participate, i.e. existing capacity, existing DR, new conventional capacity, new DR, new renewable capacity and new transmission projects that relieve constraints;
- Peak load will continue to increase over time, creating a need for new resources;
- New resources of all types (new conventional capacity, new DR, new renewable capacity, new transmission projects that relieve constraints) will be built *if and only if* they receive a sufficient capacity payment;
- A capacity payment commitment for one year approved three years in advance of the delivery year / in-service date, will be sufficient to entice investments in all types of new resources; and

- Some existing generating capacity will retire solely because they do not receive a capacity payment commitment for one year approved three years in advance of the delivery year.

If some, or all, of those underlying assumptions are inconsistent with actual market conditions in the future, it is unlikely that PJM will continue to set net Cone according to its current methodology and assumptions. Thus, while the RPM may well continue to be designed to produce market prices that average around Net CONE, the value set for net CONE may be much lower than its current level.

Our analyses of market fundamentals suggests that actual market conditions over the coming decade are likely to be different than most of these underlying assumptions, and thus that capacity prices are likely to be considerably lower than net CONE based on a gas-fired CT. In addition, if BRAs for several planning years consistently clear at prices corresponding to an excess of capacity while there is net growth in resources, the value of CONE could be reduced automatically.[10] PJM could also at any time propose and file with the FERC a new value of Cone based upon a different calculation method and/or proxy unit. In fact, PJM is required it to review the calculation of CONE every three years.[11].

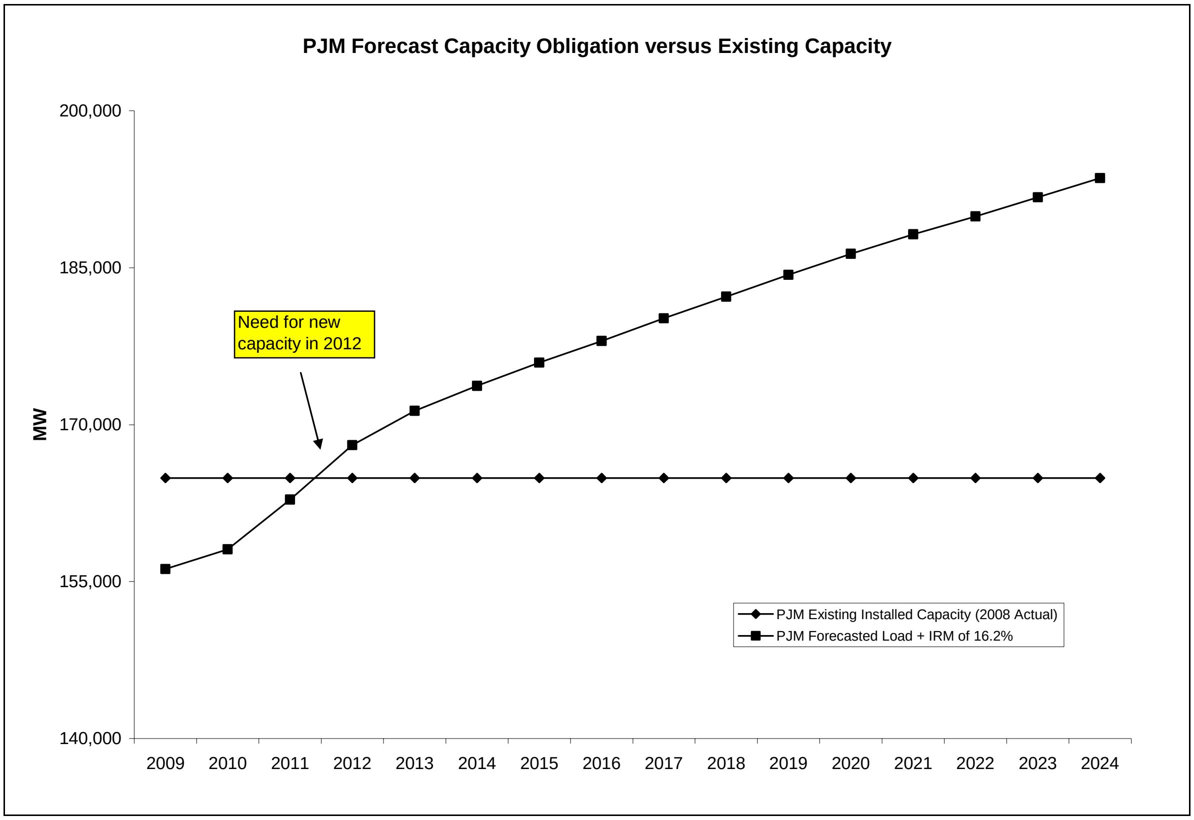
B. Load may grow slowly

PJM determines the quantity of capacity that has to be acquired in the BRA for each planning year by forecasting the capacity obligation. That capacity obligation, combined with the quantity of existing capacity and DR willing to bid into the BRA, in turn determines the quantity of new capacity that will have to be developed to satisfy the capacity obligation.

[10] PJM OATT, substitute Third Revised Sheet No. 586 as of September 18, 2009.
[11] 126 FERC ¶61,275, Order Accepting Tariff Provisions in Part, Rejecting Tariff Provisions in Part, Accepting Report, and Required Compliance Filings, March 26, 2009.

Our high level review indicates that, according to PJM's most recent long-term forecast[12], the capacity obligation will exceed existing capacity starting in 2012, as shown in Figure 2. Those estimates indicate that new capacity would be needed from that point onward.

Figure 2



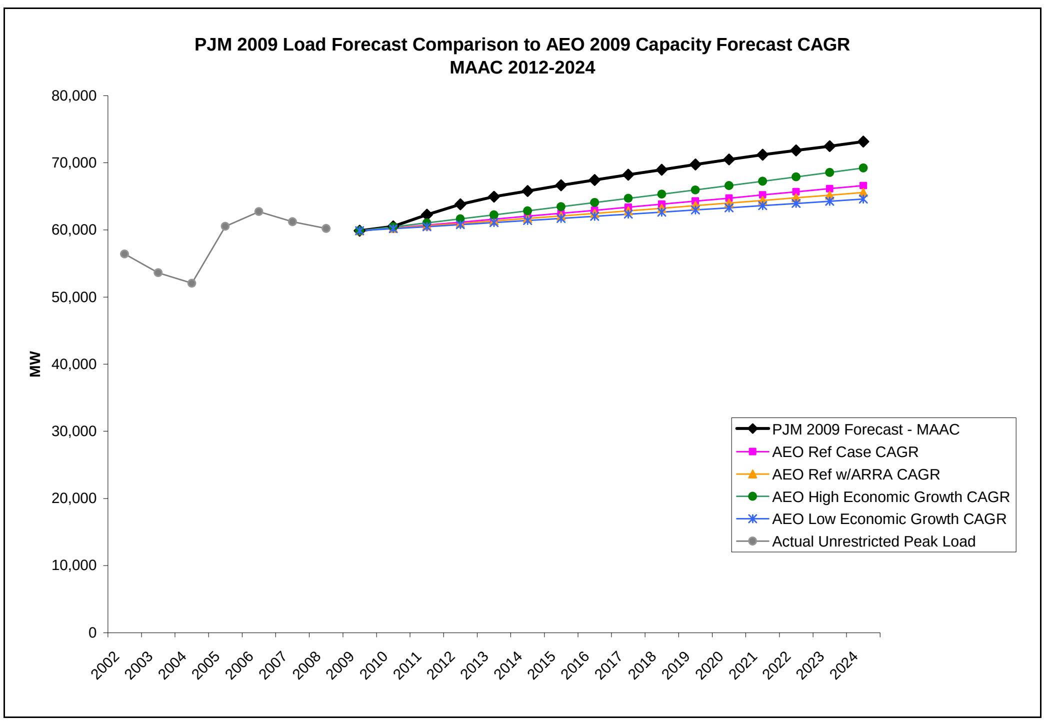
However, it is likely that peak load will grow more slowly than PJM has forecast due to a slow recovery from the current recession and the increased emphasis being placed upon energy efficiency and DR. Those factors could cause load to remain relatively flat or increase only slightly during the next decade. With no or low growth in peak load the need for new capacity could be delayed several years.

[12] PJM Manual 21, Revision 7, Appendix B

PJM currently projects that peak load will increase at a compound annual rate (CAGR) of 1.35% between 2009 and 2024.[13] However, this forecast is not consistent with other recent load forecasts from public sources. For example, EIA provides a capacity forecast for the Mid-Atlantic Area Council (MAAC) Electricity Market Module (EMM) in its Annual Energy Outlook Report (AEO).[14] The 2009 AEO updated reference case, which considers the American Recovery and Reinvestment Act of 2009 (ARRA), shows annual capacity growth of only .61% from 2009-2024.

Figure 3 compares PJM's forecast load growth for the MAAC sub-region to the growth in capacity forecast in several AEO 2009 scenarios.

Figure 3



[13] *See* PJM, 2009 Load Forecast Report, January 2009, p. 28, available at http://pjm.com/documents/~/media/documents/reports/2009-pjm-load-report.ashx (downloaded September 24, 2009).

[14] EIA, Annual Energy Outlook 2009, Supplemental Table 74, Electric Power Projections for EMM Region Mid-Atlantic Area Council, available at http://www.eia.doe.gov/oiaf/aeo/index.html (downloaded September 24, 2009).

As shown in Figure 1, the PJM load forecast CAGR is higher than all EIA forecasts. Even the CAGR in the AEO 2009 high economic growth case is lower than the PJM forecast.[15]

In fact, intervenors protesting PJM's proposed tariff changes of February 2009 argued that the macroeconomic forecast underlying the PJM load forecast greatly overestimated economic growth for the 2012 delivery year.[16] For example, James F. Wilson of LECG argued that the macroeconomic forecast used by PJM for 2012 is much higher than Aspen Publisher's Consensus of Blue Chip Financial Forecasts.[17] He noted that the PJM forecast is also higher than the average of the ten highest macroeconomic forecasts included in that consensus. Mr. Wilson found that inserting the consensus forecast into PJM's load model would reduce the forecasted load for 2012 by 3,000 MW or 2%.[18]

In the same affidavit, Mr. Wilson argued that recent PJM load forecasts have failed to capture a trend toward slowing load growth in the region that has been developing since 2005. Mr. Wilson compared the contemporaneous AEO forecast of electricity demand for the MAAC EMM to the PJM load forecast and found that the difference in growth rates translates into over 6,000 MW of peak load in 2012.[19]

In addition to macroeconomic conditions, slowing load growth is attributable to increased energy efficiency initiatives and demand response programs. The PJM load forecast only includes energy efficiency and demand resources to the extent that they have already cleared in previous RPM auctions—the impacts are not taken out of forecasted load until the program is in place and is reflected in metered load.[20] However, recent federal and state initiatives to boost investment in energy efficiency and other

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[15] The AEO 2009 high economic growth case incorporates higher population, labor force and productivity growth rates than the reference case. Due to the higher productivity gains, inflation and interest rates are lower compared to the reference case. Investment, disposable income, and industrial production are increased. Economic output is projected to increase by 3.0 percent per year between 2007 and 2030 (EIA, Assumptions to the Annual Energy Outlook, Macroeconomic Activity Module, http://www.eia.doe.gov/oiaf/aeo/assumption/macroeconomic.html).

[16] Protest Regarding Load Forecast to be used in May 2009 RPM Auction, and Affidavit of James F. Wilson, January 5, 2009, Docket Nos. ER09-412-000, EL05-1414-000, and EL05-148-000 before the Federal Energy Regulatory Commission.

[17] Aspen Publishers, Blue Chip Financial Forecasts, December 2008, and Blue Chip Economic Indicators, December 2008.

[18] Wilson Affidavit at Par. 6.

[19] Wilson Affidavit, Attachment A at Par. 7.

[20] PJM 2009 Load Forecast, Executive Summary, available at http://pjm.com/documents/reports.aspx.

conservation and demand-side measures have the potential to reduce future load below the level assumed in the RPM auction parameters.

On the federal level, the Energy Policy Acts of 2005 and 2007 set equipment and appliance efficiency standards and provided federal tax incentives for energy efficiency.[21] The American Recovery and Reinvestment Act of 2009 provided $16.8 billion for energy efficiency and renewable energy programs, including $3.2 billion in energy efficiency and conservation block grants, $5 billion in weatherization assistance, $3.1 billion to state energy plans, and $4.4 to modernize the electric grid with, among other things, demand response equipment.[22] The American Clean Energy and Security Act of 2009 (ACES), currently before the Senate, includes a combined efficiency and renewable electricity standard, support for state energy efficiency programs, smart grid advancement (including peak demand reduction goals),[23] building energy efficiency programs, lighting and appliances efficiency programs, and industrial energy efficiency programs.[24]

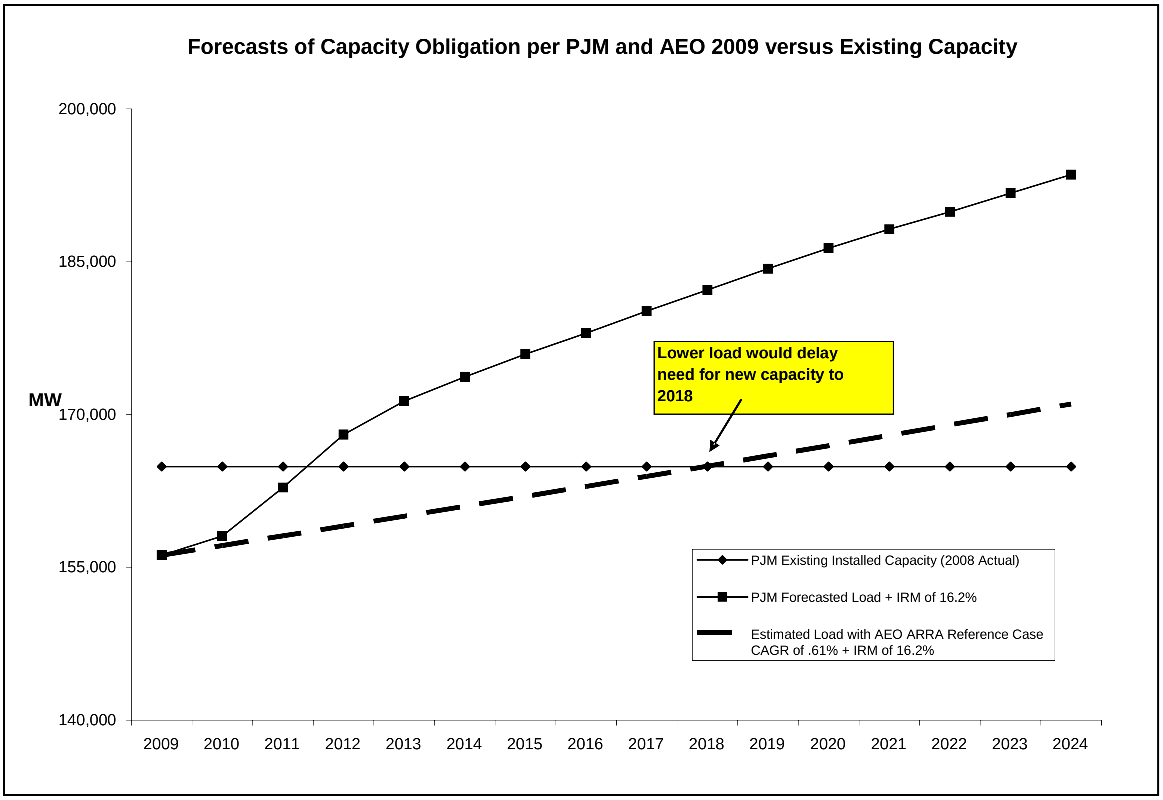
In addition to federal efficiency programs, all states within the PJM region have energy efficiency programs in place, including both regulations and incentive-based voluntary programs.[25] PJM states are also setting new targets for energy savings and peak demand reductions, and requiring they be met by law. For example, in Pennsylvania, Act 129 of 2008 requires all electric and gas utilities to participate in an energy efficiency and conservation program.[26] By May 2011, each electric distribution company (EDC) must reduce consumption by a minimum of 1% below the PUC's 2009-2012 peak load forecast and reduce peak demand by 4.5% of annual system peak in the 100 highest hours of demand measured against its 2007-2008 forecast. By May 2013, consumption must be decreased by 3% of the 2009-2010 forecast, and incremental increases to the peak load reduction target will be made if savings from the 2011 reduction are greater than the costs.[27] In New Jersey, the Energy Master Plan (EMP) calls for a reduction in peak load

[21] *See* ACEEE, "Energy Policy Act of 2005," http://www.aceee.org/energy/national/legsttus.htm, and "2007 Federal Energy Legislation," http://www.aceee.org/energy/national/07nrgleg.htm (downloaded September 24, 2009).
[22] American Recovery and Reinvestment Act of 2009, Division A, Title IV, Energy and Water Development.
[23] American Clean Energy and Security Act of 2009, Title I.
[24] American Clean Energy and Security Act of 2009, Title II.
[25] *See* Database of State Incentives for Renewables and Efficiency (DSIRE), http://dsireusa.org/.
[26] General Assembly of Pennsylvania, House Bill No. 2200 and Act 129 of 2008, Section 1.2, available at http://www.puc.state.pa.us/electric/pdf/Act129/HB2200-Act129_Bill.pdf (downloaded September 25, 2009).
[27] *Ibid*.

of 20% below current levels and a reduction in electricity demand of 5,700 MWh by 2020.[28]

Returning to PJM's long-term forecast shown earlier in Figure 2. If peak load grows according to the AEO 2009 Updated Reference Case capacity forecast[29], rather than the PJM forecast, no new capacity of any type will be required until 2018. This delay is illustrated in Figure 4.

Figure 4



C. Transmission upgrades may enable greater utilization of existing capacity

Transmission constraints affect wholesale capacity prices by limiting the ability for surplus capacity in one LDA to be used to meet the capacity obligation in a neighboring

[28] New Jersey Energy Master Plan, October 2008, available at http://www.state.nj.us/emp/ (downloaded September 25, 2009).

[29] EIA, Annual Energy Outlook 2009, Updated Reference Case, Supplemental Table 74;.

LDA. In other words, they can limit the quantity of existing capacity that can bid into a BRA for a particular LDA.

According to the PJM Regional Transmission Expansion Planning (RTEP) report, major transmission upgrades are expected to be completed over the next three to four years. To the extent that these upgrades reduce various existing transmission constraints they could affect clearing prices in future BRAs by increasing the quantity of surplus capacity in one LDA that can bid into the BRAs for a neighboring LDA or LDAs.

D. New Renewable Capacity Will Be Developed To Comply With Renewable Portfolio Standards (RPS)

RPS requirements in PJM states will increase the amount of capacity additions required by law each year over the next decade. Special renewable energy fund provisions and cost recovery mechanisms as well as financial and operational penalties suggest that suppliers are likely to comply with program targets. The continuing new additions to capacity supply from RPS requirements would therefore be expected to put increasingly more downward pressure on capacity prices over the next ten to 15 years.

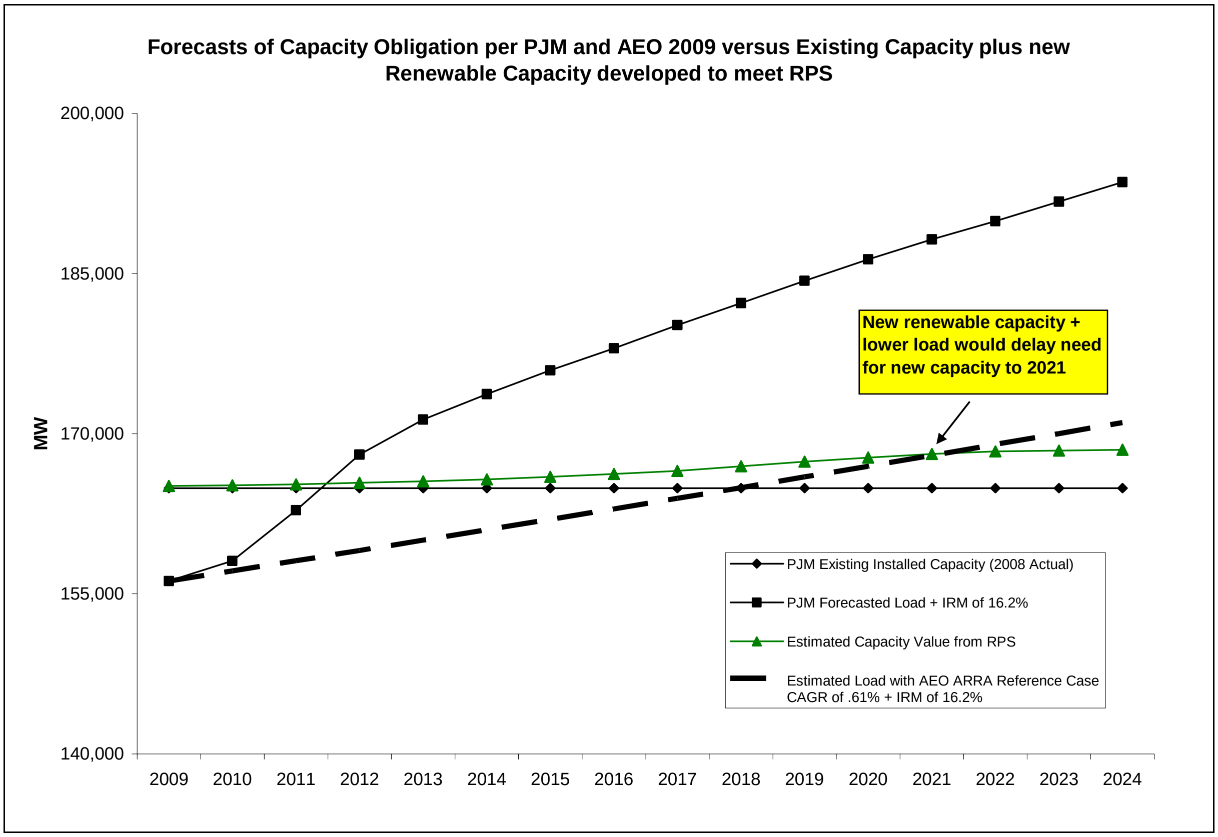
All states with utilities participating in the PJM capacity market, except for West Virginia and Indiana, currently have RPS. New Jersey's RPS, which is one of the most aggressive in the country, requires that of 12% electricity sales be generated from qualifying renewable sources by 2015, increasing to 22.5% by 2021.[30] In Maryland, 18% of electricity sales must be from tier 1 resources[31] plus an additional 2% from solar resources by 2022. The solar set-aside alone is projected to result in 1,500 MW of new capacity. Overall, PJM has 1,500 MW of new wind capacity under construction, and another 42,000 MW in its transmission queue.[32]

If load grows according to the AEO 2009 forecast, the capacity from renewable resources developed to comply with RPS could further delay the need for new

[30] Database of State Incentives for Renewables and Efficiency (DSIRE), "New Jersey," http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=1&ee=1 (downloaded September 25, 2009).
[31] Tier 1 resources include solar, wind, qualifying biomass, methane from the anaerobic decomposition of organic materials in a landfill or a waste water treatment plant, geothermal, ocean fuel cells powered by methane or biomass, and small hydroelectric plants (DSIRE, "Maryland," http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=MD05R&re=1&ee=1).
[32] PJM, Regional Transmission Expansion Plan Report (RTEP), February 27, 2009, section 2.2.4, available at http://pjm.com/documents/reports/rtep-report.aspx (downloaded September 25, 2009).

conventional capacity until 2021. The potential impact of new renewable resource capacity developed to comply with RPS requirements in states served by PJM is illustrated in Figure 5.

Figure 5



Synapse estimated the quantity of new renewable capacity developed to comply with RPS that PJM would recognize in a BRA in three steps. First we calculated the annual energy (MWh) required from new renewables in order to meet the RPS of each state each year by type of resource[33]. Then, we calculated the implied quantity of installed capacity of new renewable resources as annual energy from renewables (MWh) divided by 8,760 hours per year times the typical capacity factor for the type of resource. We assumed 30% for wind, 13% for solar and 85% for biomass. Finally, we calculated the quantity of new renewable capacity that PJM would recognize in a BRA by multiplying the installed capacity from step two by the "intermittent resource capacity

[33] Database of State Incentives for Renewables and Efficiency (DSIRE), https://dsireusa.org

factors" that PJM has established for capacity planning purposes[34]. The intermittent resource capacity factors for wind and solar resources are 13% and 38% respectively. Over this period, the estimated quantity of capacity from RPS resources grows at a CAGR of 19%.

Our analyses indicate that substantial new RPS capacity will be available in PJM, even if the RPM market continues to clear at a low price, because capacity from renewables is driven by RPS requirements rather than compensation from the RPM. All of the PJM state RPS policies include cost recovery mechanisms and special funding to cover the costs of compliance. Each of the PJM RPS programs include penalty-supported funds including Alternative Compliance Payments (ACP) and Solar Alternative Compliance Payments (SACP) that also serve as de facto cost caps. Each of the states also has special public benefits funds in place to support development of renewable energy sources. These funds are generally supported by surcharges on customer's electricity rates.[35] In Maryland, if an electricity supplier purchases solar renewable energy credits (REC) directly from a renewable on-site generator to meet the solar set-aside requirement, the duration of the contract term for the solar RECs may not be less than 15 years.[36]

In all states ACPs and SACPs serve as both cost caps and penalties for non-compliance with the RPS. Other penalties include suspension or revocation of the electric power supplier's license, disallowance of cost recovery, and prohibition of accepting new customers (as in New Jersey and Delaware).[37] In Maryland, shortfall payments are reduced on a sliding scale through 2023. These penalties, along with cost recovery mechanisms and special funding programs, help ensure that RPS targets will be met and that capacity growth from renewable resources in PJM will be sustained through the next decade.

[34] PJM 2009 Load Forecast Report; PJM Manual 21, Revision 7, Appendix B.
[35] Union of Concerned Scientists, Renewable Electricity Standards Toolkit, available at http://go.ucsusa.org/cgi-bin/RES/state_standards_search.pl?template=main (downloaded September 25, 2009).
[36] *Ibid.*
[37] *Ibid.*

4. Conclusion

Wholesale capacity prices will only approximate net CONE of a gas-fired CT if specific conditions are met. These conditions are that peak load will grow, new capacity will have to be built to meet the new load and that gas-fired CTs will be the least cost sources of that new capacity. Our analyses of market fundamentals suggests that actual market conditions over the coming decade are likely to be different than most of these underlying assumptions due to a combination of low load growth, transmission projects that reduce constraints on greater utilization of existing capacity increases supply and new renewable capacity developed to comply with RPS requirements. Therefore, capacity prices are likely to be considerably lower than net CONE based on a gas-fired CT. Future market prices could remain in the range of BRA results for 2011 and 2012, e.g. $110 to $133 per Mw-day ($40 to $46 per kw-yr) or lower rather than the $171 to $176 per Mw-day ($60 to $64 per kw-yr) suggested by net CONE.

Table 1. Utility service territories by PJM LDA

Local Deliverability Area (LDA)[2]	Utility Zone Acronym	Utility Zone Full NAME[1]	State(s)[1]
EMAAC	AE	Atlantic Electric (part of PEPCO Holdings, Inc.)	NJ
	DPL	Delmarva Power & Light	DE, MD, VA
	JCPL	Jersey Central Power & Light	NJ
	PECO	PECO Energy	PA
	PS	Public Service Electric & Gas	NJ
	RECO	Rockland Electric (East)	NJ
SWMAAC	BGE	Baltimore Gas & Electric	MD
	PEPCO	Potomac Electric Power (part of Pepco Holdings, Inc.)	MD
WMAAC	METED	Metropolitan Edison	PA
	PENLC	Pennsylvania Electric	PA
	PL (incl. UGI)	PPL Electric Utilities (subzone of PLGroup)	PA
DPL South	DPL	Delmarva Power & Light	DE, MD, VA
Dominion	DOM	Dominion	VA, NC
PSNORTH	PSNORTH	Public Service Electric & Gas	NJ
Western PJM	AEP (incl. Non-Zone Load)	American Electric Power	KY (KP) WV (APP) OH (CSP, OP) IN, MI (INM)
	APS	Allegheny Power	PA, OH (West Penn, Potomac Edison) WV (Monongahela, Potomac Edison) MD (Potomac Edison) VA (Potomac Edison, Monongahela)
	COMED	Commonwealth Edison	IL
	DAYTON	Dayton Power & Light	OH
	DLCO/DQE	Duquesne Lighting Company	PA

Table 2. Net CONE from BRA auctions for Planning Years 2007 - 2012[38]

LDA	Planning Period						AVERAGE - 2010 to 2012	
	2007-2008	**2008-2009**	**2009-2010**	**2010-2011**	**2011-2012**	**2012-2013**	$/MW-day	$/kw-yr
RTO	171.87	172.25	172.27	174.29	171.40	276.09	207.26	75.65
APS	171.87	172.25	139.69	174.29	171.40	276.09	207.26	75.65
MAAC	**171.87**	**172.25**	**148.81**	**131.87**	**171.40**	**176.44**	**159.90**	**58.36**
EMAAC	148.47	148.80	148.81	131.87	171.40	212.50	171.92	62.75
SWMAAC	158.68	159.02	159.04	112.77	171.40	176.44	153.54	56.04
DPL South	148.47	148.80	148.81	131.87	171.40	212.50	171.92	62.75
DPL	148.47	148.80	148.81	131.87	171.40	212.50	171.92	62.75
PS North	148.47	148.80	148.81	131.87	171.40	212.50	171.92	62.75
PS	148.47	148.80	148.81	131.87	171.40	212.50	171.92	62.75

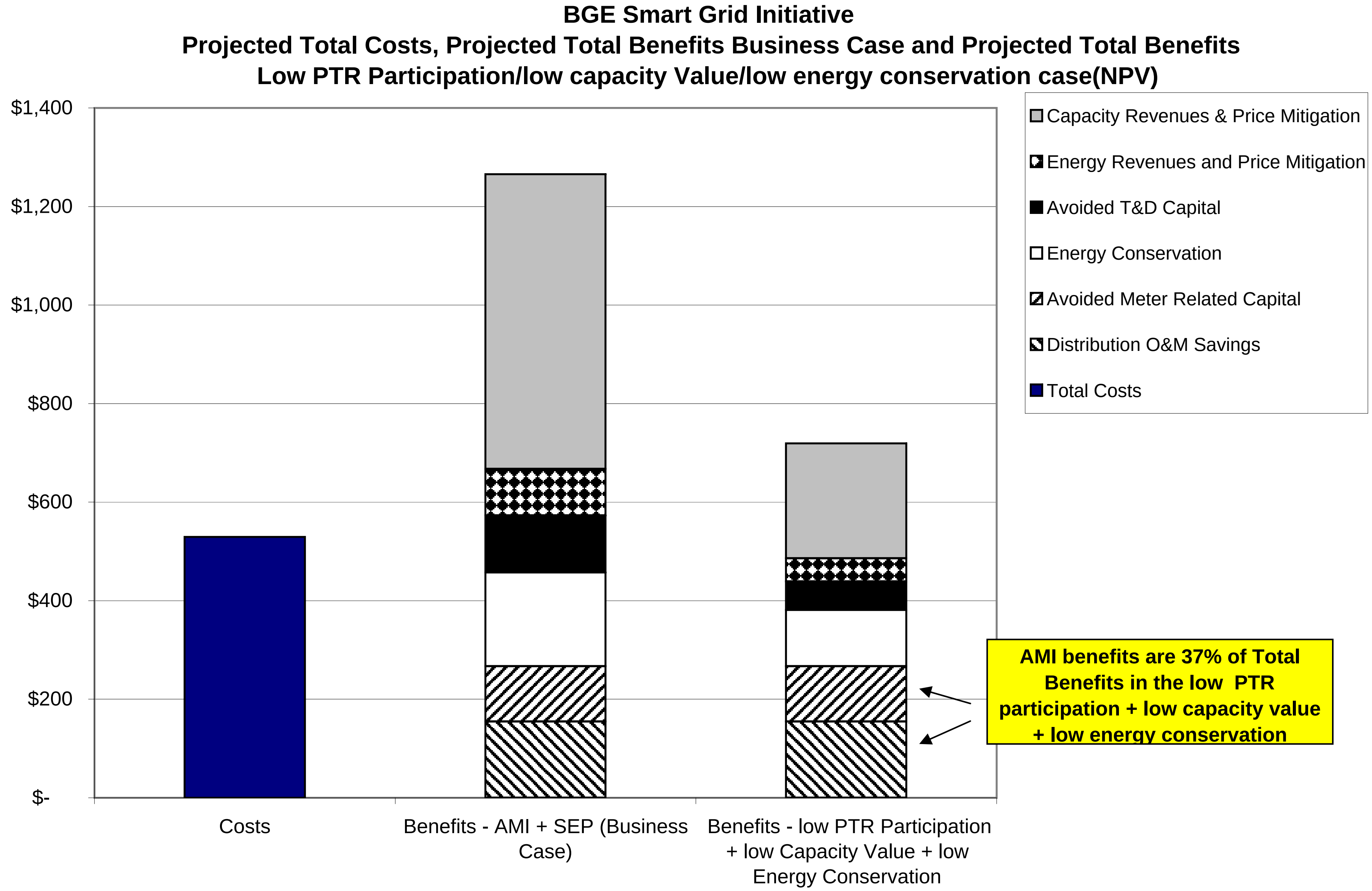
[38] BRA Planning Parameters and Results from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item07 (downloaded September 25, 2009).

Table 3. Market Prices from BRA auctions for Planning Years 2007 - 2012

LDA	Planning Period						AVERAGE - 2010 to 2012		
	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	$/MW-day	$/kw-yr	% net CONE
RTO	40.80	40.80	102.04	174.29	110.00	16.46	100.25	36.59	48%
APS	40.80	40.80	191.32	174.29	110.00	16.46	100.25	36.59	48%
MAAC	**40.80**	**40.80**	**191.32**	**174.29**	**110.00**	**133.37**	**139.22**	**50.82**	**87%**
EMAAC	197.67	197.67	191.32	174.29	110.00	139.73	141.34	51.59	82%
SWMAAC	188.54	188.54	237.33	174.29	110.00	133.37	139.22	50.82	91%
DPL South	197.67	197.67	191.32	186.12	110.00	222.3	172.81	63.07	101%
DPL	197.67	197.67	191.32	186.12	110.00	139.73	145.28	53.03	85%
PS North	197.67	197.67	191.32	174.29	110.00	185.00	156.43	57.10	91%
PS	197.67	197.67	191.32	174.29	110.00	139.73	141.34	51.59	82%

Table 4. Market Prices as % of Net Cone from BRA auctions for Planning Years 2007 - 2012

LDA	Planning Period						AVERAGE - 2010 to 2012
	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	
RTO	24%	24%	59%	100%	64%	6%	48%
APS	24%	24%	137%	100%	64%	6%	48%
MAAC	**24%**	**24%**	**129%**	**132%**	**64%**	**76%**	**87%**
EMAAC	133%	133%	129%	132%	64%	66%	82%
SWMAAC	119%	119%	149%	155%	64%	76%	91%
DPL South	133%	133%	129%	141%	64%	105%	101%
DPL	133%	133%	129%	141%	64%	66%	85%
PS North	133%	133%	129%	132%	64%	87%	91%
PS	133%	133%	129%	132%	64%	66%	82%


BGE Smart Grid Initiative
Projected Total Costs, Projected Total Benefits Business Case and Projected Total Benefits
Low PTR Participation/low capacity Value/low energy conservation case(NPV)
$1,400
$1,200
$1,000
$800
$600
$400
$200
$-
Costs
Benefits - AMI + SEP (Business Case)
Benefits - low PTR Participation + low Capacity Value + low Energy Conservation
Capacity Revenues & Price Mitigation
Energy Revenues and Price Mitigation
Avoided T&D Capital
Energy Conservation
Avoided Meter Related Capital
Distribution O&M Savings
Total Costs
AMI benefits are 37% of Total Benefits in the low PTR participation + low capacity value + low energy conservation

BGE Smart Grid Initiative - Summary of Projected Total Costs and Benefits

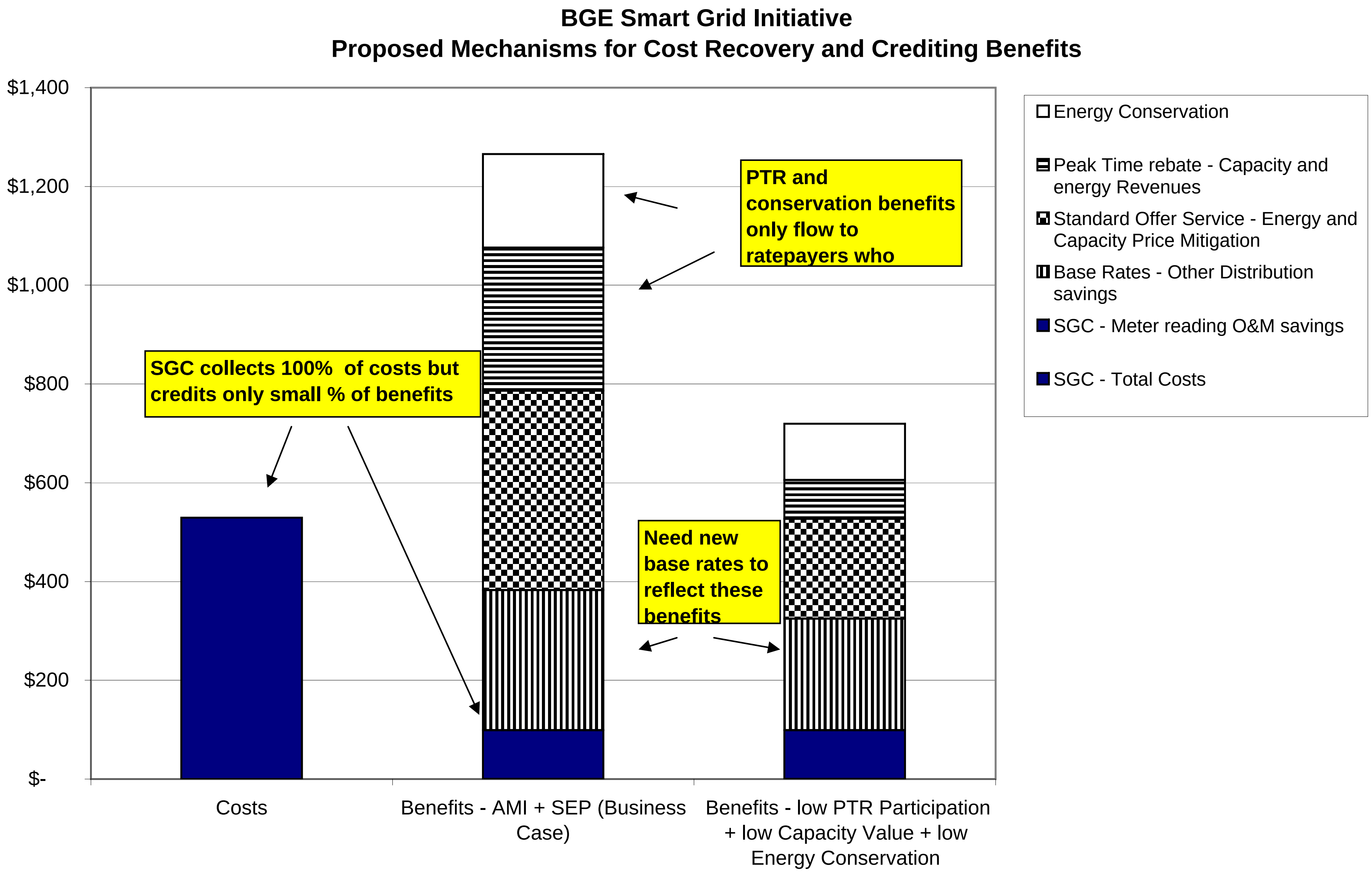
Business Case and Low PTR Participation / Low Capacity Value / Low Energy Conservation

	Case	Business Case (1)			low PTR Participation + low Capacity Value + low Energy Conservation (2)		
$'s in Millions		NPV millions		% of Benefits	NPV millions		% of Benefits
Costs	**Category**						
	Capital Expenditures	$	434		$	434	
	Operations & Maintenance Expenses	$	95		$	95	
	Funding from DOE	$	-		$	-	
	Total Costs	$	529	**42%**	$	529	**74%**
BENEFITS							
Primary Driver	**Category**						
AMI	**Distribution O&M Savings**	$	155		$	155	
	Avoided Meter Related Capital	$	112		$	112	
	Sub-total AMI	**$**	**267**	**21%**	**$**	**267**	**37%**
SEP	**Energy Conservation**	$	190	**15%**	$	114	**16%**
	Avoided Distribution Infrastructure	$	34		$	17	
	Avoided Transmission Infrastructure	$	82		$	41	
	Energy Price Mitigation	$	69		$	34	
	Energy Revenues	$	26		$	13	
	Capacity Price Mitigation	$	335		$	167	
	Capacity Revenues	$	264		$	66	
	Sub-total from Peak Reduction	$	809	**64%**	$	338	**47%**
	Sub-total SEP	**$**	**999**	**79%**	**$**	**452**	**63%**
Total Benefits - AMI +SEP		$	1,266	100%	$	719	100%
Benefit / Cost Ratio							
	AMI Benefit/ Cost Ratio		0.5			0.5	
	SEP Benefit/ Cost Ratio		1.9			0.9	
			2.4			1.4	

Sources:

1 BGE Response to Staff IR2-19, Staff-BGEIR2-19_Attachment 1, Tab 'Base'

2 Workbook A to Exhibits___JRH-4 and 7


BGE Smart Grid Initiative
Proposed Mechanisms for Cost Recovery and Crediting Benefits
$1,400
$1,200
$1,000
$800
$600
$400
$200
$-
Costs
Benefits - AMI + SEP (Business Case)
Benefits - low PTR Participation + low Capacity Value + low Energy Conservation
SGC collects 100% of costs but credits only small % of benefits
PTR and conservation benefits only flow to ratepayers who
Need new base rates to reflect these benefits
Energy Conservation
Peak Time rebate - Capacity and energy Revenues
Standard Offer Service - Energy and Capacity Price Mitigation
Base Rates - Other Distribution savings
SGC - Meter reading O&M savings
SGC - Total Costs

BGE Smart Grid Initiative - Summary of Proposed Mechanisms for Cost Recovery and Crediting Benefits

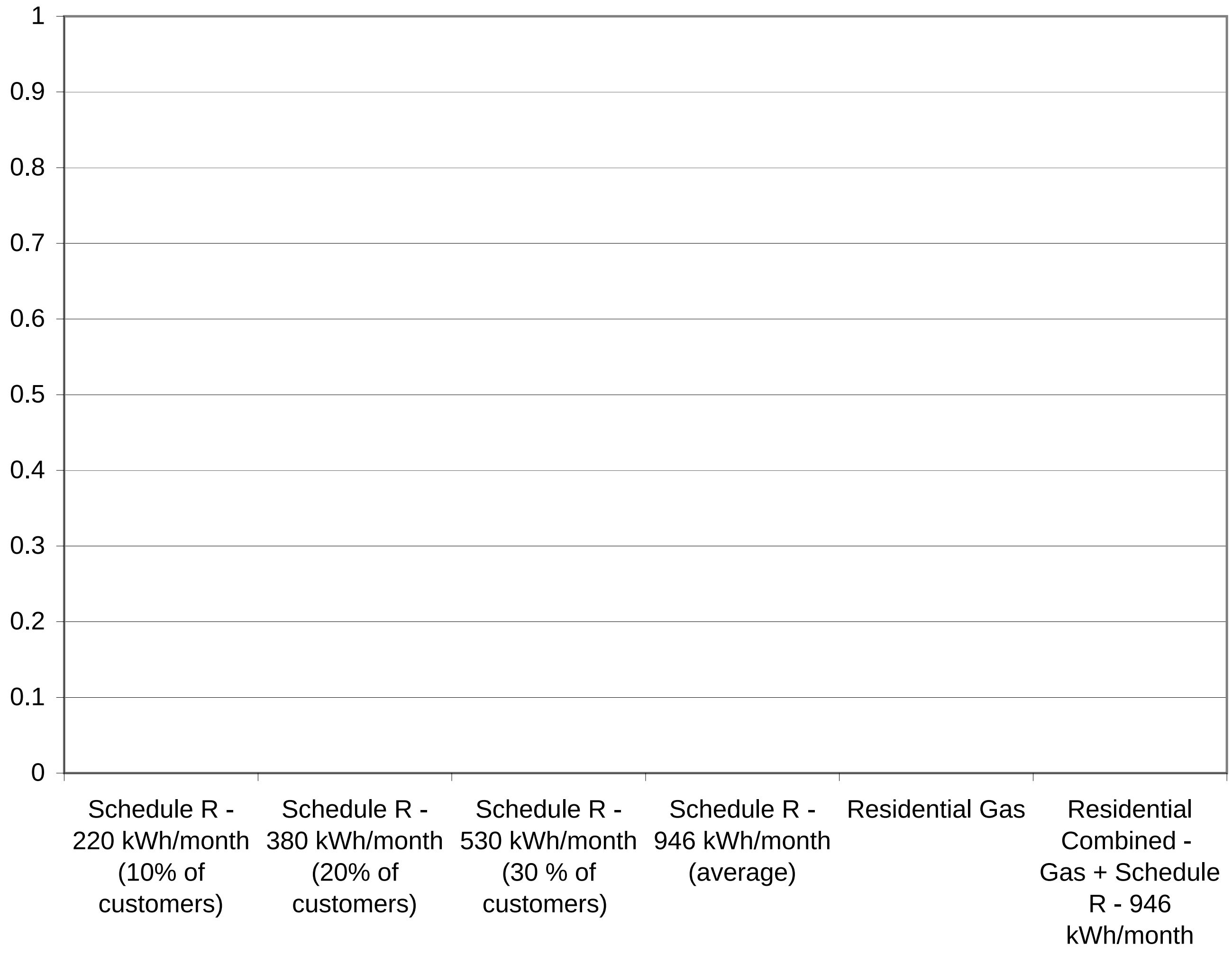
Business Case and Low PTR Participation / Low Capacity Value / Low Energy Conservation Case

Costs and Benefits	Proposed Mechanism	Categories of Costs and Benefits	Business Case (1)		low PTR Participation + low Capacity Value + low Energy Conservation (2)	
			NPV millions	% of Benefits	NPV millions	% of Benefits
Costs	**Smart Grid Charge**	**Total Costs**	$ 529		$ 529	
Benefits	**Smart Grid Charge**	**Meter reading O&M savings**	99	**8%**	99	**14%**
	Base Rates	**Other Distribution O&M Savings**	56		56	
		Avoided Meter Related Capital	$ 112		$ 112	
		Avoided Distribution Infrastructure	$ 34		$ 17	
		Avoided Transmission Infrastructure	$ 82		$ 41	
		Sub-total Base rates	$ 284	22%	$ 226	31%
	Standard Offer Service	**Energy Price Mitigation**	$ 69		$ 34	
		Capacity Price Mitigation	$ 335		$ 167	
		Sub-total SOS	$ 403	32%	$ 202	28%
	Peak Time Rebate	**Energy Revenues**	$ 26		$ 13	
		Capacity Revenues	$ 264		$ 66	
		Sub-total PTR	$ 289	23%	$ 79	11%
	Energy Conservation		$ 190	15%	$ 114	16%
		Total Benefits	1,266	100%	720	100%

Source: Workbook A to Exhibits___JRH-4 and 7

REDACTED

Increase in Residential Annual Bills in 2012 from BGE Proposed Smart Grid Charge before any offsetting savings from participation in PTR or Energy Conservation enabled by Initiative



REDACTED

Increase in Residential Annual Bills in 2012 from BGE Proposed Smart Grid Charge before any offsetting savings from participation in PTR or Energy Conservation enabled by Initiative

Customer Charges ($/month) - Residential Rate Schedules	**EXISTING RATES**	**SGC Impact**	
		$/month	%
Residential Electric			
Schedule ES	$6.00	**Redacted**	
Schedule R	$7.50		
Schedule RL-1	$12.00		
Schedule RL-2	$12.00		
Residential Gas	$13.00		
Schedule R + Gas	$19.00		
Annual Bills of Residential Customers in 2012	**Annual Bill at Existing rates**	**SGC Impact**	
	$/year	$/year	%
Residential Electric			
Schedule R - 220 kWh/month (10% of customers)	$503.49	**Redacted**	
Schedule R - 380 kWh/month (20% of customers)	$771.79		
Schedule R - 530 kWh/month (30 % of customers)	$1,023.32		
Schedule R - 946 kWh/month (average)	$1,721.03		
Residential Gas	$1,252.24		
Residential Combined - Gas + Schedule R - 946 kWh/month	$2,973.28		
Source - Workbooks to Exhibit___(JRH-8)			

BGE Responses to Selected Data Requests

OPC DR 2-3

OPC DR 2-4

OPC DR 2-5

OPC DR 2-8

OPC DR 2-13

OPC DR 2-15

OPC DR 2-16

OPC DR 2-18

OPC DR 2-22

OPC DR 2-23

OPC DR 2-24

OPC DR 4–1

OPC DR 4-2

OPC DR 4-12

OPC DR 4-13

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 2

Item No.: OPCDR2-3

Direct Testimony of Mr. Vahos pages 7 to 9 and Exhibit DMV-1 Sections 2, 3, 4 and 6.

i. Please provide all analyses prepared by, or for, BGE of the advantages and disadvantages of postponing the start of deployment until 2011 or later.

ii. If BGE has not analyzed the advantages and disadvantages of starting deployment in 2011 or later, please explain why not.

RESPONSE:

i. BGE has not prepared such an analysis.

ii. As stated in the testimony of Mr. Case, BGE's proposal addresses the question of why deployment should not be delayed. In summary, a delay would 1) jeopardize the ability to reduce costs to customers that could be gained from the receipt of grant monies of up to $200M, as the Department of Energy prefers 'shovel ready' projects in the evaluation process for the grant applications; 2) postpone the customer benefits to be gained from BGE's Smart Grid proposal, estimated to be in excess of $2.6 billion; 3) defer the benefits of increased reliability; 4) impede progress towards the EmPOWER Maryland goals for a 15% reduction in peak demand by 2015.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 2

Item No.: OPCDR2-4

Direct Testimony of Mr. Vahos pages 7 to 9, Exhibit DMV-1 Section 4 Figure 3 and Staff Request 1-55.

i. Please provide all assumptions and workbooks used to develop these projections, as well as the projections by year after 2015.

ii. Please describe the baselines that BGE proposes to use to measure the actual savings in each of the four categories in the Figure.

iii. Please describe the process through which the actual savings in each of the four categories in Figure 3 will be measured and booked to the cost recovery tracker.

RESPONSE:

i. Please refer to CONFIDENTIAL *Attachment 1*.

ii. BGE is only proposing to measure the actual savings in the "Meter Reading" category as this is the only category that serves to reduce the Smart Grid charges. For baseline purposes, BGE will use an up-to-date 12-month "test year" (e.g., calendar year 2009) that captures all of the meter reading costs noted in Section 4.2.1 of Exhibit DMV-1 in the Direct Testimony of Mr. Vahos. The test year amount will be used to reduce the gas and electric Smart Grid charges going forward. As noted on page 19 of the Direct Testimony of Mr. Vahos, BGE currently estimates this total amount to be $7.6 million.

iii. Please see response to ii) above.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 2

Item No.: OPCDR2-5

Direct Testimony of Mr. Vahos pages 7 to 9, Exhibit DMV-1 Section 4 Figure 4 and Staff Request 1-55.

i. Please provide all assumptions and workbooks used to develop these projections, as well as the projections by year after 2015.

ii. Please describe the baselines that BGE proposes to use to measure the actual savings in each of the four categories in the Figure.

iii. Please describe the process through which the actual savings in each of the four categories in Figure 3 will be measured and booked to the cost recovery tracker.

RESPONSE:

i. Please refer to CONFIDENTIAL *Attachment 1* referenced in the response to OPCDR2-4, i.

ii. BGE is not proposing to measure the actual savings in any of the four categories, as none of these categories serve to reduce the Smart Grid charges. However, these benefits represent avoided costs which will serve to reduce customer bills to a level lower than they otherwise would have been. These benefits will flow through to customers via other cost recovery mechanisms such as base rates and the SOS mechanism.

iii. Please see response to ii) above.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 2

Item No.: OPCDR2-8

Smart Energy Pricing Benefits. Direct Testimony of Mr. Vahos pages 7 to 9 and Exhibit DMV-1 Section 5.

i. Market Penetration, page 13 Exhibit DMV-1. Please provide all analyses upon which upon which BGE based its assumption of maximum participation of 36% in Peak Rewards. If BGE has not prepared such an analysis please explain why not.

ii. Wholesale capacity prices, page 14 Exhibit DMV-1 and Staff 2 -54. Please provide all analyses upon which BGE based its assumption that the capacity price will average $176 per MW-day. If BGE has not prepared such an analysis please explain why not.

iii. Capacity price mitigation, page 17 Exhibit DMV-1 and Staff 2 -54. Please provide all analyses upon which BGE based its assumption that BRAs will clear at reserve levels between IRM -3% and IRM +5%. If BGE has not prepared such an analysis please explain why not.

iv. Capacity price mitigation, page 17 Exhibit DMV-1 and Staff 2 -54. Please provide all analyses upon which BGE based its assumption that MAAC VRR sets the capacity price in 4 years at points between (b) and (c) and SWMAAC sets it in one year between (a) and (b). If BGE has not prepared such an analysis please explain why not.

v. Capacity price mitigation, page 17 Exhibit DMV-1 and Staff 2 -54. Please provide all analyses upon which BGE based its assumption that VRR curves will not change due to changes in net Cone. If BGE has not prepared such an analysis please explain why not.

vi. Capacity price mitigation, page 17 Exhibit DMV-1 and Staff 2 -54. Please provide all analyses upon which BGE based its assumption that VRR curves will not change due to changes in the structure of the RPM. If BGE has not prepared such an analysis please explain why not.

vii. Capacity price mitigation, page 17 Exhibit DMV-1 and Staff 2 -54. If BGE assumes that these assumptions will apply to delivery years from 2017-2018 onward, please provide all analyses upon which BGE based that assumption. If not please provide the assumptions for 2017-2018 onward. If BGE has not prepared such an analysis please explain why not.

RESPONSE:

i. BGE's legacy Active Load Management program for residential air conditioning control peaked in participation in the year 1997 with about 255,000 customers participating, or about 26% of the residential market. BGE's goal with its PeakRewards program is to surpass the maximum legacy penetration rate through the deployment of a well-designed and cost-effective service that is attractive to customers, coupled with an aggressive market plan. BGE recognized early that an aggressive build-out of demand response and conservation resources will be the most cost-effective way to contribute significantly toward maintaining the necessary reliability levels throughout the Southwest MAAC region.

In order to most effectively carryout a comprehensive PeakRewards marketing campaign, BGE partnered with Honeywell Utility Solutions. Honeywell was charged with developing an aggressive marketing campaign that will reasonably achieve a penetration rate characteristic of a fully saturated market. Provided below are the various marketing channels and the amount of participant customers that each channel is expected to achieve over the four-year deployment campaign. The total number of participating customers by fourth-quarter 2011 is estimated at about 416,000, or about 36% of the estimated 1.15 million residential customers. This rate of penetration for the PeakRewards deployment is nearly 40% higher than the maximum penetration achieved with the legacy program, and the most aggressive demand response program in the country.

Marketing Channel	Participants Achieved
Direct Mail	272,000
Telemarketing	93,000
Community Outreach	20,000
TV, Radio, Print, Web	20,000
Multi-family Canvassing	11,000
TOTAL	416,000

ii. Over the long-term BGE expects that the average cleared capacity price will oscillate closely around the marginal value of capacity. BGE did not conduct an analysis to establish the marginal value of capacity because it agrees with PJM in that the Net CONE is representative of the marginal value of capacity. Therefore, BGE's long-run estimate of capacity price is equal to the 2012-13 delivery year Net CONE in real dollars.

iii. BGE believes that extreme surpluses or deficiencies in the supply of capacity relative to the prevailing demand represented by the Variable Resource Requirement demand curve clearing below IRM+5% or above IRM-3% are unlikely throughout the five-year capacity price mitigation period. BGE does not have the resources to conduct simulations and analyses of future RPM auctions. An attempt at a credible analysis of such magnitude would have been very costly and time consuming, and, in BGE's opinion, would not have necessarily led to better business case assumptions. With regard to BGE's Smart Grid Proposal, BGE believes that reasonable sensitivity analyses around key assumptions are suitable to gauge the proposal's cost-effectiveness.

iv. See response to OPC Data Request 2, Item 8, iii.

v. Changes in the value of net CONE will not necessarily result in changes to the slopes of the VRR curve. (See response to OPC Data Request 2, Item 8, iii)

vi. Changes in the structure of RPM will not necessarily result in changes to the slopes of the VRR curve. (See response to OPC Data Request 2, Item 8, iii)

vii. As stated on page 17 Exhibit DMV-1, capacity price mitigation was limited to five years, ending in the 2017-18 delivery year. (See response to OPC Data Request 2, Item 8, iii)

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 2

Item No.: OPCDR2-13

Direct Testimony of Mr. Vahos pages 13 to 27 and Exhibit DMV-1 Section 6 Figure 8. Post Deployment Costs.

i. Please describe the types of costs expected under each of the four categories.

ii. Please provide all numerical assumptions and calculations used to develop these projections in an operational workbook, including annual projections from 2015 onward.

iii. If BGE is proposing to recover these post-deployment costs through the Smart Grid Tracker Mechanism please provide the rationale.

RESPONSE:

i. Please refer to CONFIDENTIAL *Attachment 1* provided in response to OPCDR2-4, i.

ii. Please refer to CONFIDENTIAL *Attachment 1* provided in response to OPCDR2-4, i.

iii. BGE is currently proposing to recover all Smart Grid costs, including post-deployment costs, through the tracker mechanism. BGE's current view is that a separate cost recovery mechanism is appropriate in light of the anticipated variation of SEP rebate payments from year to year that can be driven primarily by weather..

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 2

Item No.: OPCDR2-15

Direct Testimony of Mr. Vahos page 19 and Exhibit DMV-1.

i. Please relate the $7.6 million meter reading benefit to the tracker to the projection of annual reductions in meter reading O&M expenses in Figure 3 of Exhibit DMV-1.

ii. Please explain why BGE is not proposing to credit the tracker with reductions in meter operation O&M expenses?

RESPONSE:

i. The $7.6 million cited is the estimated annual cost of the meter reading function immediately prior to its dissolution. This is the amount to be explicitly credited to customers in the tracker with any additional savings to be credited to customers in future base rate proceedings.

ii. Unlike meter reading expenses, BGE does not track meter operations expenses into separate and distinct projects as these operations cross over multiple functional areas of our business. As such, O&M savings in the meter operations area do not lend themselves the clear-cut "before and after" quantification facilitated by the virtual elimination of the meter reading function. However, customers will receive the benefits of these avoided costs as these savings will serve to reduce customer bills to a level lower than they otherwise would have been. These benefits will flow through to customers via other cost recovery mechanisms such as base rates and the SOS mechanism.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 2

Item No.: OPCDR2-16

Direct Testimony of Mr. Vahos pages 13 to 27 and Exhibit DMV-1. Is BGE proposing to file a rate case in a specific future year in order to reflect the reductions in O&M and CAPEX in Figures 3 and 4 in its revenue requirements? If yes, what is the future year? If no, why not?

RESPONSE:

BGE is not proposing to file a rate case in a specific year in this proceeding, which is limited to our proposed Smart Grid Initiative application. Any rate case proposals would be litigated in a separate proceeding.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 2

Item No.: OPCDR2-18

Direct Testimony of Mr. Vahos page 20 and Staff 2-29. Allocation of meter costs.

i. Meter and module costs, Figure 8 Exhibit DMV-1. Please provide the projected average unit installed cost of meters and modules by customer or rate class.

ii. If BGE maintains there is no material difference in the average unit installed cost of meters and modules by customer or rate class, please provide all supporting analyses.

iii. If there is a material difference in the average unit installed cost of meters and modules by customer or rate class, please explain why BGE is not proposing to reflect that difference in its allocation of those costs

RESPONSE:

i. BGE did not prepare the projected average unit installed cost of meters by rate class as the Smart Grid charges do not require such an analysis to be prepared. Rather, the electric and gas Smart Grid charges allocate total meter costs by rate class using peak load and number of meters, respectively.

ii. Please see response to i) above.

iii. Please see response to i) above.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 2

Item No.: OPCDR2-22

Time-of-Use pricing and Plug-In Hybrid Electric Vehicles (PHEV). Direct Testimony of Mr. Manuel, pages 4 and page 10 and POC 1-14.

i. Please extend the projection requested in OPC 1-14 to 2020.

ii. Please provide all analyses prepared by, or for, BGE of the impact of a $0.06 per kWh price differential on the timing of electricity consumption by PHEV owners. If BGE has not analyzed that price elasticity please explain why not.

iii. Please provide all analyses prepared by, or for, BGE of the T&D costs it would incur to provide service to residential customers who acquire a PHEV. If BGE has not estimated these marginal T&D costs please explain why not.

iv. Is BGE proposing to develop a TOU rate for its distribution service to reflect the marginal cost of providing service to residential customers who acquire a PHEV? If yes, please indicate when BGE plans to file that proposal. If no, please explain why not.

RESPONSE:

i. Please refer to the original response to OPC Data Request 1, Item 14, which applies to all years going forward from 2010.

ii. BGE has not prepared such an analysis as our proposal in the instant proceeding does not include any pricing structures specific to PHEVs.

iii. BGE has not prepared such an analysis as we believe that appropriate PHEV pricing structures can alleviate the need to incur additional T&D costs to serve residential customers who acquire a PHEV. These rates would be easily implemented using the Smart Grid meters and application systems. To the extent that BGE does not move forward with its Smart Grid proposal, significant T&D costs are anticipated.

iv. Please see responses to ii) and iii) above.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 2

Item No.: OPCDR2-23

Time-of-Use pricing and distributed generation. Direct Testimony of Mr. Manuel, pages 4 and page 10 and POC 1-15.

i. Please extend the projection requested in OPC 1-15 to 2020.

ii. Please provide all analyses prepared by, or for, BGE of the impact of a $0.06 per kWh price differential on the financial incentive for residential customers to install some form of generation on their premises. If BGE has not analyzed that price elasticity please explain why not.

iii. Please provide all analyses prepared by, or for, BGE of the T&D costs it would avoid if residential customers install distributed generation. If BGE has not estimated these marginal T&D costs please explain why not.

iv. Is BGE proposing to develop a TOU rate for its distribution service to reflect the avoided distribution cost due to residential customers who install distributed generation? If yes, please indicate when BGE plans to file that proposal. If no, please explain why not.

RESPONSE:

i. Please refer to the original response to OPC Data Request 1, Item 15, which applies to all years going forward from 2010.

ii. BGE has not prepared such an analysis as our proposal in the instant proceeding does not include any pricing structures specific to distributed generation.

iii. BGE has not prepared such an analysis as our proposal in the instant proceeding does not deal with the effects of distributed generation.

iv. Please see responses to ii) and iii) above.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 2

Item No.: OPCDR2-24

Peak Time Rebate. Direct Testimony of Mr. Manuel, page 6 lines 8 to 10.

i. Please provide all analyses prepared by, or for, BGE of the relative stability of net CONE and of the cleared capacity price.

ii. Are the incentives that BGE provides under the PeakRewards program based upon NetCone? If not, upon what value are they based.

RESPONSE:

i. BGE did not conduct an analysis of the relative stability of net CONE and cleared capacity prices. BGE based this conclusion on its understanding of the key drivers of the two values. Changes in the value of net CONE year-over-year are primarily driven by a limited number of variables that generally do not display a great deal of volatility, including cost of construction and energy margins for a gas-fired combustion turbine; whereas the value of cleared RPM prices year-over-year are primarily driven by a wide array of variables that can cause significant swings in auction results, including prevailing supply and demand conditions, transmission capabilities, retirement and new entry volumes, net CONE values, participants' bid strategies, etc. This basic understanding of the key drivers of change led BGE to conclude that it is more likely that the value of net CONE will be more stable than the value of cleared capacity prices.

ii. No. At this time the value of the PeakRewards incentive is fixed and is not tied directly to the value of net CONE. The goals in designing the PeakRewards incentive structure were to recognize the increased value of capacity with the implementation of RPM; offer more choices with corresponding incentives for the customer than the single 50% cycling option of the legacy program, and keep it simple and highly marketable. From these goals came the PeakRewards incentive construct -- $50 for 50% cycling, $75 for 75% cycling and $100 for 100% cycling. Although not tied to any specific capacity market value, the tiered incentive structure reflects a higher value for capacity (legacy incentive was $40) and presents a simple, yet compelling value proposition to the customer.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 4

Item No.: OPCDR4-1

Direct Testimony of Mr. Case, pages 18 and 19 and response OPC 2-18. Mr. Case lists a number of "soft" benefits of the Smart Grid Initiative. Is Mr. Case implying that if these soft benefits were quantified in some manner they would materially increase the benefits already quantified? If yes, please provide the basis for that position.

RESPONSE:

Yes, the soft benefits from the Smart Grid Initiative have the potential to materially increase the benefits already quantified.

Example 1: Potential to improve the cost effectiveness of BGE's demand response program

Based on a recent survey, less than 60% of BGE's legacy AC load control switches are operating when an event is called. With the existing 1-way communications system, it is not possible to remotely confirm that a switch is operational. Over time, the operability of the system declines as switches stop working or are removed by customers and HVAC contractors. This operability degradation is a common issue among industry peers who have 1-way demand response systems.

The Smart Grid Initiative provides a 2-way communications network that could be used to immediately notify BGE when a demand response device is not pinged successfully so that repairs can be made. It is expected that this functionality would increase operability to near 100%. The improvement in operability would increase peak load reduction. This additional demand response could be sold into the capacity markets for revenue and passed along to customers to improve the cost effectiveness of the demand response program. At this time, BGE does not include any incremental benefit due to this functionality.

Example 2: Potential to achieve additional conservation benefits via in-home displays

The Smart Grid Initiative provides a 2-way communications network that could be used to communicate with in-home displays. These displays can provide the customer with near real-time usage, rate and bill data to help them conserve energy. Studies have shown that when customers are given this information, they reduce their energy usage by 5%-15%. BGE assumed a conservative 1% net energy benefit, so additional benefits beyond this amount would significantly improve the business case.

Both of these opportunities are being actively investigated by BGE and would be quantified via future business case analysis. However, without the Smart Grid Initiative as an enabler, these opportunities cannot exist in a cost effective manner.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 4

Item No.: OPCDR4-2

Direct Testimony of Mr. Case, pages 18 and 19 and response OPC 2-18. Please explain why each of the following "soft" benefits of the Smart Grid Initiative cannot be quantified either as a dollar value, or in percentage or physical terms

a. Impact on customer bills
b. Improved reliability
c. Improved Customer Service
d. Support for Home Device
e. Support for electric vehicles
f. Support for electric generation

RESPONSE:

a. Customer bill impacts have been quantified. Please see response to Staff DR4-6.

b. The BGE operational cost savings due to Improved Reliability have been quantified. See Excel file entitled "Master – Benefit – Costs – October Start – PSC Submittal.xls" submitted in response to Staff Information Request 1, Item 55. The data that addresses reliability benefits can be found on tab "Annual Benefit Pivot Table", Element ID 48. BGE has not quantified the value of Loss of Load or the value of faster restoration to its customer base because such evaluations can be subjective. To remain conservative, BGE chose not to perform an evaluation of these benefits.

c. Certain benefits of Improved Customer Service have been quantified as cost reductions to BGE operations, including the effect of the Smart Grid Initiative aiding with faster investigations of bill inquiries and allowing the Company to remotely connect and disconnect customers for move-ins and move-outs. See Excel file entitled "Master – Benefit – Costs – October Start – PSC Submittal.xls" submitted in response to Staff Information Request 1, Item 55. The data that addresses the cost reductions can be found on tab "Annual Benefit Pivot Table", Element IDs 7, 16, 34, 35, 36, 37, 38, 39, 46. The "soft" benefits of the Smart Grid Initiative allowing for on-demand meter reads and allowing customers to see their hourly usage on the web prior to their bill being rendered were not quantified because such evaluations can be subjective. To remain conservative, BGE chose not to perform an evaluation of these benefits.

d. The benefit of support for Home Devices has not been quantified. BGE is considering plans to pilot home display products to measure customer impacts.

Due to rapidly evolving technology and standards, BGE does not feel comfortable committing to particular solutions or vendors without a customer pilot.

e. The benefit of Support for Electric Vehicles has not been quantified. Electric vehicles and the method by which they will be electrically charged are emerging technologies. While it is expected that the Smart Grid will play a role in managing these technologies, quantification of benefits cannot be calculated with a reasonable level of accuracy until the technology further matures.

f. The benefit of Support for Electric Generation has not been quantified. As distributed generation resources proliferate, it is expected that the Smart Grid will play a role in maintaining a stable and reliable electric system through the use of interval and bi-directional metering data. However, benefits were not quantified due to the uncertainty around customer acceptance, pricing and government incentives that impact penetration rates.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 4

Item No.: OPCDR4-12

Direct Testimony of Dr. Faruqui, pages 18 to 23.

a. Please explain, when applying these elasticities to project the load response of a particular group, whether one should first make a downward adjustment for the assumed percentage of non-participants. Please provide the rationale for your explanation.
b. Please explain how, if at all, these elasticity results relate to the elasticity survey results discussed in your article "Inclining Toward efficiency", Public Utilities Fortnightly, August 2008.
c. Please explain how, if at all, these elasticity results relate to the EPRI study that finding that 44 percent of residential customers had no price elasticity.

RESPONSE:

a. The elasticities used in Brattle's analysis represent the price responsiveness of an average BGE residential customer and are based on experimental evidence from the Smart Energy Pricing (SEP) pilot. Brattle used these elasticities to predict the demand response of an average BGE residential customer. These calculations do not require a downward adjustment for the assumed percentage of non-participants, since all the impacts are presented for an average BGE residential customer.

b. The elasticity values discussed in Dr. Faruqui's article, "Inclining Toward Efficiency" represent customer responses in the short-run and the long-run to changes in the overall price of electricity or rate level. They do not deal with changes in rate design, such as those represented by the SEP pilot. In my analysis of the data from that pilot, Dr. Faruqui estimated two sets of elasticities: substitution and daily price elasticities. The substitution elasticities are not comparable to the elasticities discussed in his article as these elasticities reflect the substitution behavior between the periods rather than a conservation behavior. The daily price elasticities can be compared to those in Dr. Faruqui's article as they reflect the conservation behavior of the customers.

c. As mentioned earlier, Brattle's elasticities represent the response of the average customer. There is a lot variation in demand response across customers behind the average estimate. Some customers do not respond at all. Some respond marginally and some respond a lot. What matters in the end is their collective behavior and the best predictor of that is the response of the average customer.

Case No. 9208
Baltimore Gas and Electric Co.
Response to OPC Data Request 4

Item No.: OPCDR4-13

Direct Testimony of Dr. Faruqui. Exhibit AF-1, page 8 indicates that between 2002-2007 you reviewed a wide range of dynamic pricing options for mass-market customers in California and prepared analyses with estimates of likely participation in and demand response to critical peak and/or dynamic rates (including PTR). Please provide every public estimate you have prepared in the last five years of residential customer participation in and demand response to critical peak and/or dynamic pricing, by utility service territory or jurisdiction, and the actual rate of participation and demand response that has ultimately occurred in that utility service area or jurisdiction.

RESPONSE:

Dr. Faruqui's work is in the public domain and can be accessed by consulting the websites of the appropriate regulatory agencies. It provided input to the business case for advanced metering infrastructure (AMI) that was being developed by his clients. Since AMI is still in the process of being rolled out around the country, and since dynamic pricing cannot be offered to customers without AMI, it is not possible to provide the requested information on the actual rate of participation and demand response that has ultimately occurred in various utility service areas.