**CASE NO. 9208**

**IN THE MATTER OF**

**BALTIMORE GAS AND ELECTRIC COMPANY**

**FOR AUTHORIZATION TO DEPLOY A
SMART GRID INITIATIVE
AND TO ESTABLISH A SURCHARGE MECHANISM
FOR THE RECOVERY OF COST**

**BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION**

**DIRECT TESTIMONY OF J. RICHARD HORNBY
ON BEHALF OF THE
MARYLAND OFFICE OF PEOPLE'S COUNSEL**

**OCTOBER 13, 2009**

**CASE NO. 92O8**
**DIRECT TESTIMONY OF J. RICHARD HORNBY**

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## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, EMPLOYER, AND PRESENT POSITION.**

A. My name is James Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, MA 02139.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?**

A. I am testifying on behalf of the Maryland Office of People's Counsel (or "OPC").

**Q. PLEASE DESCRIBE SYNAPSE ENERGY ECONOMICS.**

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including: electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

**Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.**

A. I am a consultant specializing in planning, market structure, ratemaking, and gas supply/fuel procurement in the electric and gas industries. Over the past twenty years, I have presented expert testimony and provided litigation support on these issues in approximately 100 proceedings in over thirty jurisdictions in the United States and Canada. Over this period, my clients have included staff of public utility commissions, state energy offices, consumer advocate offices and marketers.

Prior to joining Synapse in 2006, I was a Principal with CRA International and, prior to that, Tabors Caramanis & Associates. From 1986 to 1998, I worked with the Tellus Institute (formerly Energy Systems Research Group), initially as Manager of the Natural Gas Program and subsequently as Director of their Energy Group. Prior to 1986, I was Assistant Deputy Minister of Energy for the Province of Nova Scotia.

I have a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology (MIT) and a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now merged with Dalhousie University. I have attached my resume to this testimony as Exhibit___(JRH-1).

**Q. PLEASE SUMMARIZE YOUR EXPERIENCE WITH THE ECONOMICS OF, AND RATEMAKING FOR, ENERGY EFFICIENCY AND DEMAND RESPONSE, INCLUDING DEMAND RESPONSE ENABLED BY ADVANCED METERING INFRASTRUCTURE (AMI).**

A. My experience with energy efficiency measures and policies began over thirty years ago as a project engineer responsible for identifying and pursuing opportunities to reduce energy use in a factory in Nova Scotia. Subsequently, in my graduate program at MIT I took several courses on energy technologies and policies, and prepared a thesis analyzing federal policies to promote investments in energy efficiency. After MIT, I spent several years with the government in Nova Scotia, during which time I administered a provincial program to promote energy conservation in the industrial sector and later included energy conservation in all sectors as part of energy plans developed for the province.

Since 1986, as a regulatory consultant I have helped review and prepare numerous integrated resource plans in the gas and electric industries, and testified regarding cost allocation and rate design. During the past several years I have led projects to estimate the avoided costs of electricity and natural gas in New England for a coalition of efficiency program administrators. In addition I have reviewed the economics of demand response, and of AMI proposals in New Jersey, Maine, the District of Columbia and Pennsylvania. I have testified regarding the alignment of utility financial incentives and rates with the pursuit of energy efficiency in proceedings in North Carolina, South Carolina, Indiana and Minnesota.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. Baltimore Gas and Electric Company ("BGE" or "the Company") filed an application dated July 13, 2009 requesting approval to deploy a Smart Grid Initiative ('Initiative') and to establish a new tracker or rider, the Smart Grid Charge (SGC), to recover the costs of the Initiative. In his Direct Testimony BGE witness Case provides an overview of the application. BGE witness Butts provides a detailed description of the Initiative and its benefits, costs, and risks. BGE witness Vahos provides the business case for the Initiative and describes the SGC rider in general. BGE witness Manuel describes the proposed Smart Energy Pricing rate schedule for residential electric customers and the tariffs to implement the SGC Rider. BGE witness Faruqui describes the conclusions of the Company's Smart Energy Pricing pilot from 2008.

The OPC has retained three witnesses to address the Company's two requests from the perspective of residential customers, myself, Ms. Nancy Brockway and Mr. David Effron.

- My testimony addresses the ratemaking implications of the Company's requests, the uncertainties associated with the Initiative's projected costs and benefits, and allocation and rate design underlying the proposed cost recovery. **(**The fact that I do not address other aspects of the Company's filing should not be interpreted to mean I agree with those aspects.)
- Ms. Brockway addresses the uncertainties associated with the Company's projections of residential customer reductions in electricity due to the Initiative, the problems with including time-of-use ('TOU') rates for generation service in

the Company's proposed new Smart Energy Pricing ("SEP") default tariff for residential service, the uncertainties associated with smart grid technology and consumer protection issues.

- Mr. Effron addresses the Company's proposed cost recovery tracker.

Q. **WHAT DATA SOURCES DID YOU RELY UPON TO PREPARE YOUR TESTIMONY AND EXHIBITS?**

A: I relied primarily on the Direct Testimony, exhibits, and workpapers of the Company witnesses. I also relied upon Company responses to various data requests, most of which I provide in Exhibit No. ___ (JRH-9). In addition, I relied upon analyses of the PJM wholesale market for capacity and various reports on AMI and dynamic pricing[1].

[1] The difference between dynamic pricing and traditional time-of-use (TOU) pricing is the manner in which the specific pricing periods are set. Under TOU the pricing periods are static, they are set in a rate case and remain unchanged between rate cases. For example BGE is proposing TOU prices for a summer peak period, defined as weekdays from 2 p.m. to 7 p.m. excluding specified holidays, for a summer off-peak period and for a non-summer period. In contrast, under its proposed dynamic pricing BGE would determine the periods when its the Peak Time Rebate ('PTR) would apply on a "dynamic" basis according to anticipated changes in system conditions from day to day during the summer. For example, BGE proposes to notify customers approximately 18 hours in advance of an impending critical peak period during which its PTR would apply.

## II. CONCLUSIONS AND RECOMMENDATIONS

**Q. PLEASE SUMMARIZE YOUR CONCLUSION AND RECOMMENDATION REGARDING ADVANCED METERING INFRASTURE PROPOSALS IN GENERAL AND BGE'S PROPOSAL IN PARTICULAR FROM A PUBLIC POLICY PERSPECTIVE.**

A. A number of policymakers apparently assume that implementation of AMI, and dynamic pricing enabled by AMI, will produce reductions in annual electricity costs and greenhouse gas emissions that will far exceed its costs and that will justify its bill impacts. Unfortunately, those assumptions are not supported by the details of utility proposals for deployment of AMI and dynamic pricing, including BGE's proposed Initiative. Instead, analyses indicate that utilities are primarily proposing to reduce some distribution service costs and to enable reductions in energy consumption, and associated emissions in less than 100 hours per year.

My general conclusion is that utility proposals for deployment of AMI and dynamic pricing, including BGE's proposed Initiative, are unlikely to produce large reductions in annual electricity costs or in annual greenhouse gas emissions. Based upon that conclusion, my general recommendation is that such proposals should be judged on their financial merits, with the burden of proof placed on their proponents. Since BGE management has chosen to propose this specific major investment, I recommend that the Commission require the Company to bear the burden of proving that the Initiative is reasonable.

**Q. PLEASE SUMMARIZE YOUR CONCLUSION AND RECOMMENDATION REGARDING THE PROJECTED TOTAL BENEFITS AND COSTS OF BGE'S PROPOSED INITIATIVE.**

A. My general conclusion is that there is considerable uncertainty regarding the projected total benefits of the Initiative as well as some uncertainty regarding projected costs. These uncertainties arise from the lack of long-term experience with the full-scale deployment of AMI and dynamic pricing such as the Smart Grid Initiative that BG&E is proposing. In particular, over 60% of the projected total benefits of the Initiative hinge on the Company's assumption that over 75% of residential customers will respond to the new PTR on a sustained basis for over 15 years, 2012 to 2027. Moreover, approximately 75% of that sub-set of projected benefits, representing over 45% of total projected benefits, hinge on the Company's second assumption that avoiding one kW of generating capacity will be worth $64 per year over 15 years. These uncertainties create a financial risk, i.e., the risk that actual benefits from the Initiative may prove to be substantially less the Company's projections. This financial risk is relevant to the Commission's decision regarding approval of the Company's request as well as to its decision regarding cost recovery.

Based upon that conclusion I recommend that the Commission take this financial risk into consideration when making its decision as to whether to approve or reject the Company's request. If the Commission does approve the Initiative, I recommend that it take this financial risk into consideration when deciding upon the method of cost recovery. In particular, I recommend that the Commission hold the Company to its projected costs as well as to its projected savings in distribution service operating and maintenance ('O&M") expenses.

**Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING BGE'S PROPOSALS FOR RECOVERING THE COSTS OF THE INITIATIVE FROM RATEPAYERS AS WELL AS FOR CREDITING BENEFITS TO RATEPAYERS.**

A. The Company proposes to recover the Initiative's entire projected cost of $800 million from all rate classes, both electric and gas, through a new SGC that would operate independent of base rates. The proposed SGC is expressed in $ per meter per month, i.e. it would be an unavoidable monthly fixed charge.

The Company proposes to flow approximately 8% of the projected benefits of the Initiative, the savings in meter-reading expenses, to ratepayers through the SGC. It expects the remaining 92% of the projected benefits to flow to ratepayers through four additional mechanisms - future changes in base rates, future changes in rates for Standard Offer Service due to the mitigation of wholesale prices, PTRs to ratepayers who reduce peak load in response to that pricing and energy conservation by ratepayers who respond to usage and pricing information provided by the Initiative.

The cost recovery aspects of the Company's proposed Initiative include the level of annual revenue requirements to be recovered, the allocation of those revenue requirements among rate classes and the design of the specific rates by rate class to recover those allocated revenue requirements. According to fundamental ratemaking principles one would expect to see the cost recovery aspects of an expenditure of this magnitude addressed in a general rate case. The Company's proposals are not guided by either a COS study or an analysis of bill impacts, and it is requesting recovery via surcharge, i.e. outside of base rates. The absence of these analyses is of particular concern since the Company's proposed SGC will increase customer charges of residential electric and gas customers by a significant amount, which in turn will lead to significant increases in the bills of low usage residential customers.

My general conclusion is that, as a basis for recovering expenditures of this magnitude and complexity, the Company should have prepared a cost-of-service ('COS") study to guide its allocation its proposed allocation of the Initiative's revenue requirements among rate classes. In addition, it should have used the results of that COS study and an analysis of bill impacts to guide its proposal to recover the revenue requirements allocated to residential customers via a monthly customer charge.

Based upon that conclusion I recommend that the Commission require the Company to present the results of a COS study and an analysis of bill impacts before approving recovery of any costs of the Initiative from residential customers via a customer charge, and only allow such recovery to continue for a limited period. In addition, I recommend that the Commission require the Company to file a general rate case no later than 2012 in order to re-set its base rates to reflect AMI related savings in its distribution service costs as well as to address the allocation of AMI-related revenue requirements and the design of rates to recover those revenue requirements.

Finally, if approved, I recommend that the Commission require the Company to move recovery of PTR costs from the SGC to an appropriate rider. In addition, I recommend that the Commission limit the amount the Company can collect from ratepayers to fund PTR costs in any year net of revenues it receives from PJM.

## III. POLICY AND RATEMAKING IMPLICATIONS OF COMPANY REQUESTS

**Q. PLEASE SUMMARIZE THE COMPANY'S SMART GRID INITIATIVE.**

A. The Company's proposed Initiative consists of a two-way communications network, AMI and SEP (Case Direct, p. 5).

Under the AMI component the Company would replace essentially all existing electric meters, replace or upgrade essentially all gas meters as well as install communications equipment and information technology (IT) hardware and software to operate the AMI system, store meter data and enable new business capabilities. The Company will make these investments between 2010 and 2015 at a projected total nominal capital cost of $641 million. In addition the Company projects O&M expenditures of $194 million for a total nominal project cost of over $800 million. The Company considers this to be a very significant investment (Case Direct, p. 27).

Under the SEP component the Company would implement a new tariff, R-SEP, in 2012 to replace all of its existing residential tariffs. The primary new features of the SEP tariff would be TOU rates for generation service and a Peak Time Rebate (PTR). The Company expects the PTR will motivate 77% of its residential customers to reduce their electricity consumption during peak periods of five hours each on up to twelve weekdays each summer.

**Q. DO OTHER UTILITIES HAVE LONG-TERM EXPERIENCE WITH THE PERFORMANCE AND ECONOMICS OF AMI AND DYNAMIC PRICING ON A SYSTEM-WIDE OR FULLY DEPLOYED BASIS?**

A. No. Utilities have conducted a number of pilot projects testing AMI and dynamic pricing on a limited basis. However, it is only in the last few years that several United States utilities have received regulatory approval to fully deploy AMI and dynamic pricing tariffs on their systems.  In fact, most of those utilities are currently in the process of completing that deployment, as indicated in Exhibit MCC-2 of Mr. Case's Direct Testimony.  For example, in its response to OPC DR 4-13 the Company stated that "…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 was unable to provide statistics on the actual rate of residential customer participation in, and demand response to, critical peak and/or dynamic pricing by utility service territory or jurisdiction.

The absence of robust empirical evidence regarding the performance and economics of AMI and dynamic pricing on a system-wide basis over time results in considerable uncertainty regarding both long-term technical performance and the magnitude of peak load reductions that will actually be sustained in the long-term in response to dynamic pricing approaches such as PTR or CPP.  In an effort to help reduce that uncertainty, and help stimulate the economy, the recent federal stimulus bill, i.e., the American Recovery and Reinvestment Act of 2009, H.R. 1, 11th Congress (2009) ('ARRA') approved appropriations to fund Smart Grid Demonstration Projects as well as a Smart Grid Investment Matching Fund to help support full-deployment of AMI by utilities who meet the grant selection criteria.

**Q. DOES THERE APPEAR TO BE A MISCONCEPTION REGARDING THE EXTENT TO WHICH FULL DEPLOYMENT OF AMI AND DYNAMIC PRICING WILL LEAD TO REDUCTIONS IN ANNUAL ELECTRICITY BILLS AND GREENHOUSE GAS (GHG) EMISSIONS?**

A Yes. Much of the enthusiasm for AMI and dynamic pricing among policy makers appears to be based upon assumptions that full deployment of AMI and dynamic pricing will lead to material reductions in annual electricity bills and in greenhouse gas emissions. Unfortunately, these assumptions are not supported by the actual details of the various AMI filings that I have reviewed to date, including BGE's proposed Smart Grid Initiative. In fact, these filings indicate that full deployment of AMI and dynamic pricing are only likely to produce very modest reductions in annual electricity bills and greenhouse gas emissions for two main reasons.

First, the installation of AMI and associated enabling of dynamic pricing, in and of themselves, do not reduce customer electricity consumption or the emissions of greenhouse gases from the generation of electricity to supply that consumption. Instead, actual reductions in annual bills and GHG associated with that consumption, will only be achieved if individual customers actually reduce their electricity consumption in response to dynamic prices in every peak period, year after year.

Second, deployments of AMI and dynamic pricing such as the Company's proposed Initiative primarily enable reductions in peak load rather than reductions in annual electricity consumption. Reductions in peak load are referred to as demand response (DR) while reductions in annual electricity consumption are referred to as energy conservation or energy efficiency (EE). As illustrated in Exhibit__(JRH-2), DR has very limited impacts on annual energy consumption and the annual GHG resulting from the electricity generated to supply that annual consumption.

- DR typically results in little or no material reduction in annual electricity consumption, and associated GHG, because it occurs in very few hours each year. For example, BGE is proposing to achieve reductions in response to the PTR up to 60 hours per year, less than 1 percent of the 8,760 hours in a year. While the reduction in those peak hours tends to have a very high economic value, it still represents a relatively small portion of customer annual usage and annual bills.

- EE measures, in contrast, not only lead to reductions in electricity consumption during the 60 hours of peak demand, like DR, but also in all the other hours when electricity affected by that measure is being used.

In fact, most utilities have a strong financial incentive to deploy AMI and dynamic pricing in a manner that will enable reductions in peak load rather than reductions in annual electricity consumption. Major reductions in peak load do not result in significant reductions in the annual revenues collected by utilities, and hence do not reduce their earnings. In contrast, unless a utility has some form of revenue stabilization type mechanism such as decoupling, major reductions in annual electricity consumption do result in significant reductions in their annual revenues and their earnings.

Third, the timing and magnitude of the capacity costs avoided due to DR can be more difficult to estimate than the timing and magnitude of the electric energy costs avoided due to EE. For example, a 1 kWh reduction in electricity consumption from energy conservation or EE results in a corresponding immediate reduction in the quantity of electricity generated, after adjustments for system losses. That quantity of electricity generation is clearly avoided. In contrast, a 1 kW reduction in peak load from DR does not automatically produce a corresponding immediate reduction in the quantity of capacity being held to ensure reliable service for that load. Instead, decisions regarding the quantity of generation, transmission and distribution capacity needed for reliable service are made several years before the year in which the actual load occurs. Thus, to avoid capacity those decision makers need to be convinced that the reduction in peak load will continue over their long-term planning horizon before they will decided to approve a lower quantity of capacity. The fact that utilities and curtailment service providers have the ability to bid reductions in peak load into wholesale capacity markets in PJM and elsewhere has helped to reduce the uncertainty associated with projections of avoided wholesale generation capacity costs.

**Q. HAS THE NATIONAL ASSOCIATION OF REGULATORY COMMISSIONERS (NARUC) EXPRESSED CONCERNS REGARDING THE POTENTIAL FOR ADVERSE RATE AND BILL IMPACTS FROM A RAPID TRANSITION TO FULL DEPLOYMENT OF AMI?**

A Yes. In his March 3, 2009 testimony to the United States Senate Committee on Energy and Natural Resources, New Jersey Commissioner Frederick Butler, President of NARUC, expressed a number of concerns regarding a rapid move to full deployment of Smart Grid systems. In that testimony, attached as Exhibit__ (JRH-3). President Butler makes a number of important points regarding consideration of ratepayer reaction:

*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.*

*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…..*

*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.*

*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.*

*We have to remember that the Smart Grid will only achieve its vast potential if consumers embrace it.*

Even if there were no uncertainty associated with the projected benefits of the Smart Grid, Mr. Butler's comments indicate that it is essential to consider the impacts on ratepayers when assessing proposals for full deployment. Moreover, since there uncertainties regarding the projected benefits of AMI and dynamic proposals such as BGE's proposed Initiative, a rigorous assessment is even more critical.

**Q. FROM AN ENERGY OR ENVIRONMENTAL POLICY PERSPECTIVE IS BG&E OBLIGATED TO IMPLEMENT FULL DEPLOYMENT OF AMI AND/OR DYNAMIC PRICING?**

A. No. I understand that BGE, like other Maryland utilities, is trying to implement programs and rate designs that will enable it to meet the goals for reductions in per capita electricity demand and annual consumption that EmPOWER Maryland has established. However, from a policy perspective my understanding is that these are policy goals that the state would like to see achieved in a manner consistent with other important goals, such as controlling and stabilizing electricity bills. Moreover, my understanding is that BGE has the flexibility to propose the particular approach, or portfolio of approaches, it considers most cost-effective to achieve those important policy goals. In other words, BGE is not legally obligated to implement its proposed Initiative, or any other full deployment of AMI and dynamic pricing. Instead, BGE management has decided to propose the Initiative from the range of possible strategies available to them. For example, there are many alternative approaches available to achieve demand reduction such as pursuing additional EE, which reduces peak load as well as annual consumption, or pursuing incremental DR from large commercial and industrial (C&I) customers. Thus, from a ratemaking perspective BGE bears the burden of proving that its Initiative will not only achieve these policy goals, but that it will do so in a manner that results in reasonable rates.

## IV. UNCERTAINTIES ASSOCIATED WITH PROJECTED COSTS AND BENEFITS

**Q. PLEASE SUMMARIZE THE BUSINESS CASE FOR THE COMPANY'S PROPOSED SMART GRID INITIATIVE.**

A. Mr. Vahos summarizes the business case for the Company's proposed Initiative on pages 3 to 12 of his Direct Testimony. He presents the details of that business case in Exhibit DMV-1. Mr. Vahos used a Total Resource Cost (TRC) to evaluate the Initiative. Under this approach he compared his projection of the total cost of the Initiative, regardless of who paid for what costs, to his projection of its total benefits, regardless of who received which benefits.  He projected these costs and benefits over the period 2010 – 2026 (‘Planning Horizon”), and then calculated their net present value (NPV).

**Q. PLEASE DISCUSS THE PROJECTED COSTS OF THE PROPOSED INITIATIVE.**

A. Mr. Vahos estimates the projected cost of the Initiative will be $835 million, with a NPV of $529 million.  This amount consists of $434 million in capital expenditures and $95 million in O&M expenses.

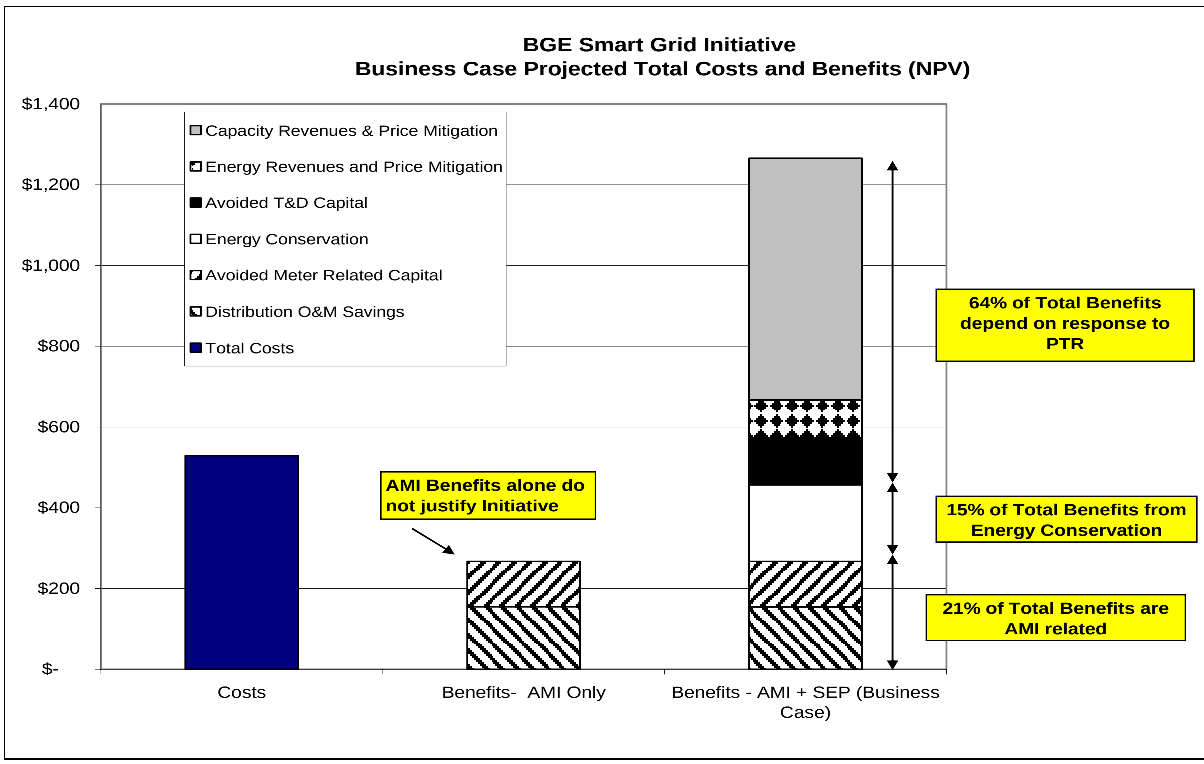
My first comment is that this projection is subject to some uncertainty – there is a chance that actual costs may be higher than this projection.  As discussed by Ms. Brockway, the fact that some technical standards are still being finalized creates a risk that additional costs may incurred if some of the technologies deployed now prove to be incompatible with the standards that are ultimately established in the future.

My second comment is that these projected costs do not represent all of the costs that are likely to be incurred if this Initiative is approved.  One set of additional costs will be the amounts that ratepayers spend on in-home devices, such as smart thermostats and other controls, in order to automate their response to the PTR.  In addition, this projection also does not include any incremental costs that may result from the method through which the Company recovers its stranded investment in existing meters, should the recovery of those un-depreciated assets be approved (Vahos Direct, p.16).  Finally, the projection does not include additional costs that the Company may propose if the Initiative is approved, such as in-home displays (response to OPCDR 4-2d) or a demonstration project (Case Direct, p. 10).

**Q. HOW DO THE BENEFITS PROJECTED IN THE BUSINESS CASE COMPARE TO THE PROJECTED COSTS OF THAT CASE.**

A. Mr. Vahos estimates that the Initiative will produce $2,635 million in benefits, with a NPV of $1,000 million (Vahos Direct, p.5). These projected benefits produce a TRC benefit-to-cost ratio of 2.4. His estimate reflects eight categories of benefits, of which he attributes two to AMI and six to SEP.

The NPV of these projections are summarized in the chart below, which is attached as Exhibit___(JRH-4). The projected costs are presented in the first bar. The projected benefits from AMI alone are presented in the second bar. These AMI related benefits are much less than the projected costs and would not justify the Initiative. The projected benefits from AMI plus SEP are presented in the third bar.




The total projected benefits in the business case, presented in the third bar, can be grouped into six major components, as indicated in Table 1.

| **Table 1 – Summary of Company projected benefits of Initiative** | | | | |
|---|---|---|---|---|
| **Projected Benefit** | **Benefits bar in Exhibit___(JRH-4)** | | **NPV (million)** | **% of Total** |
| | **Component / Block #** | **Shading** | | |
| **AMI related** | | | | |
| distribution O&M savings | first | left-to-right diagonal | $155 | 12% |
| avoided meter-related capital expenditures | second | right-to-left diagonal | $112 | 9% |
| **SEP related** | | | | |
| energy conservation | third | White | $190 | 15% |
| avoided distribution service transmission and distribution (‘T&D”) capital expenditures | fourth | Black | $116 | 9% |
| energy revenues from PJM and wholesale electric energy price mitigation | fifth | black and white diamonds | $94 | 7% |
| capacity revenues from PJM and wholesale capacity price mitigation | Sixth | Grey | $599 | 47% |
| **Total** | | | **$1,266** | **100%** |

**Q. PLEASE DISCUSS THE PROJECTED BENEFITS OF THE PROPOSED INITIATIVE.**

A. As noted, the Company projects eight categories of benefits, of which two are driven by AMI and six are driven by SEP.

The two categories of projected benefits attributed to AMI are savings in future distribution service O&M expenses and avoided future meter-related capital expenditures. These AMI related projected benefits total $267 million, producing a TRC benefit to cost ratio of 0.5. The projected AMI benefits would not be sufficient to justify the project, as indicated in Exhibit___(JRH-4). When added to the SEP related benefits, the AMI benefits account for 21 percent of the overall total projected benefits.

The first of the six categories of projected benefits attributed to SEP is energy conservation, i.e. reductions in annual electricity consumption due to increased information on electricity consumption and prices. This category accounts for 15 percent of total projected benefits as indicated in Exhibit___(JRH-4).

The remaining five categories attributed to SEP account for 64 percent of total projected benefits as indicated in Exhibit___(JRH-4). All five categories of benefits depend upon the Company's assumptions regarding reductions in peak load by customers who will respond to the PTR. Those categories are:

- future distribution service transmission and distribution ('T&D") capital expenditures that the Company assumes it will avoid;
- energy revenues that the Company assumes it will receive from PJM as compensation for bidding peak load reductions into the PJM wholesale electric energy market; and
- mitigation of wholesale electric energy prices that the Company assumes will result from bidding peak load reductions into the PJM wholesale energy market;
- capacity revenues that the Company assumes it will receive from PJM as compensation for bidding peak load reductions into the PJM wholesale capacity market; and
- mitigation of wholesale capacity prices that the Company assumes will result from bidding peak load reductions into the PJM wholesale capacity market.

These SEP related projected benefits total $999 million and produce a benefit to cost ratio of 1.9 under the TRC test. These SEP projected benefits, when added to the AMI related projected benefits, produce a total projected benefits of 1,266 with a TRC benefit to cost ratio of 2.4.

**Q. DO THE MAJORITY OF THE PROJECTED BENEFITS HINGE UPON A FEW KEY ASSUMPTIONS?**

A. Yes. The projected benefits of the proposed initiative are based upon numerous assumptions. However, four assumptions underlie the majority of the projected benefits and are therefore particularly critical.

The first major assumption is that 77% of residential customers will respond to the PTR on a sustained basis over fifteen years. As noted earlier, approximately 64 percent of total projected benefits depend upon this assumption. Ms. Brockway discusses that threshold assumption in her Direct Testimony.

The second major assumption is that capacity revenues from PJM, and the resulting mitigation of capacity prices, will reflect a capacity value of $176 per MW-day, equivalent to $64 per kw-year, over fifteen years. As noted earlier, of the 64 percent of total benefits that depend on the reductions from PTR assumption, approximately 47 percent depend upon this second assumption. I discuss this second assumption later in my testimony.

A third major assumption is that residential customers will reduce their annual use by 1% in response to the price information they receive from the Initiative. This assumption accounts for approximately 15 percent of total projected benefits. Ms. Brockway discusses this energy conservation assumption in her Direct Testimony.

The fourth major assumption is that the Company would have actually made the future investments in meter-related capital costs that it is projecting to avoid due to AMI as well as the future T&D capital expenditures that it is projecting to avoid due to reductions in peak load. I do not have the expertise to analyze the reasonableness of those projections. The Company does not plan to measure and report those avoided costs according to its responses to OPC DR2 - 4, 2-5 and 2-15.

**Q. DOES THE COMPANY PROJECT THAT THE INITIATIVE WILL BEGIN PRODUCING BENEFITS AS SOON AS IT BEGINS ITS EXPENDITURES?**

A. No. Vahos Direct, p.11. As indicated in Exhibit ___JRH- 5, the Company projects that it will incur the bulk of its projected costs between 2010 and 2013 while the Initiative will not begin producing benefits until 2012. The majority of those benefits are projected to be achieved between 2012 and 2017.

That Exhibit again highlights the extent to which the total amount of benefits depend upon a few categories which in turn depend upon the four key assumptions discussed earlier. Capacity revenues from PJM and wholesale capacity price mitigation are the dominant projected benefit between 2014 and 2017. In the longer-term, after 2017, savings from four categories account for the majority of benefits. Those three categories are distribution O&M savings, energy conservation, capacity revenues from PJM and capacity price mitigation.

**Q. DOES THE COMPANY ACKNOWLEDGE THAT THE PROJECTIONS IN ITS BUSINESS CASE ARE UNCERTAIN?**

A. Yes. Mr. Vahos notes the Total Resource Cost (TRC) analysis under the Company's business case "…is based on estimates and judgments that are subject to risks, uncertainties, and other important factors that could cause the actual costs and benefits to be different from the amounts estimated." (Vahos Direct, p. 10).

That statement implies that Company is not proposing to bear any of the financial risk that actual costs may be higher than its projection, or that actual benefits may be lower than its projection. That implication should be of particular concern to ratepayers since my analyses indicate that the actual benefits may be much less than those projected in the business case.

**Q. DID THE COMPANY EVALUATE THE IMPLICATIONS OF THE UNCERTAINTY ASSOCIATED WITH ITS PROJECTIONS?**

A. Yes. Mr. Vahos illustrates the "sensitivity" of the business case to changes in various underlying projections (Vahos Direct, p.10). He calculates TRC results for eleven separate possible futures or scenarios, some with either lower benefits or higher costs than the business case and others with either higher benefits or lower costs.

I have presented the TRC results of eight scenarios, as well as the business case, ranked from low to high in Table 2. The table excludes three scenarios with varying degrees of DOE Funding because the award of those grants is expected in October and thus is not a long-term uncertainty.

**Table 2 – Summary of BGE Sensitivity Analyses**

| **Scenario** | **TRC benefit to cost ratio** |
|---|---|
| Lower Projected PTR Participation (39% versus 77% in business case) | 1.6 |
| 25% Increase in Projected Capital Costs | 2.0 |
| Lower EE Level (0% versus 1% in business case) | 2.0 |
| 50% Decrease in Projected Monetized Capacity Revenues | 2.1 |
| **Business Case** | **2.4** |
| 50% Increase in Projected Monetized Capacity Revenues | 2.6 |
| Higher Projected PTR Participation (100% versus 77% in business case) | 3.0 |
| 25% Decrease in Projected Capital Costs | 3.3 |
| Higher EE Level (5% versus 1% in the business case) | 3.8 |

**Q. DID THE COMPANY EVALUATE ANY COMBINATIONS OF THOSE POSSIBLE FUTURES?**

A. No.

**Q. DID MR. VAHOS INDICATE THE RELATIVE PROBABILITIES OF EACH SCENARIO?**

A. No. The Company obviously believes that its business case to be the most likely scenario. However, that belief appears to be based upon the Company's judgment, as Mr. Vahos has not provided any analyses of the relative probability of each scenario.

**Q. DO YOU AGREE THAT THE BUSINESS CASE IS THE MOST LIKELY SCENARIO?**

**A.** No. My analyses, combined with those presented by Ms. Brockway, indicate that the future is more likely to unfold somewhere between the levels of PTR participation, capacity values and energy conservation savings assumed in the business case and much lower levels. I have labeled that lower benefit scenario as a low PTR participation, capacity values and energy conservation case.

**Q. BEFORE PROVIDING THE BASIS FOR EXPECTING A LOWER BENEFIT SCENARIO, PLEASE EXPLAIN WHY THE POSSIBILITY OF A LOWER BENEFIT SCENARIO IS RELEVANT TO THE COMPANY REQUESTS IN THIS PROCEEDING.**

A. The possibility of a lower benefit scenario is relevant to the Company requests in this proceeding because the Company is not proposing to bear any of the financial risk associated with such a scenario. Under its proposed cost recovery approach the Company will make the same AMI investment and earn the same return on that investment regardless of the amount of benefits actually received by ratepayers.

The Company has two basic requests at issue in this proceeding, i.e. a request for approval of the Smart Grid Initiative and a request for approval of a cost recovery mechanism. The Company maintains that its request for the Initiative should be approved because its business case projects total benefits that substantially exceed projected total costs. The possibility that future may actually produce a lower benefit scenario rather than the business case scenario would not be particularly relevant to approval of that request if BGE was proposing to recover its costs in base rates, or through a cost recovery mechanism under which it guaranteed, or was bound by, all or a significant portion of those projections. In other words if BGE was proposing to bear all, or a significant portion, of the financial risk (and reward).

However, since BGE is in fact proposing to bear little, if any, of that financial risk the possibility that future may actually produce a lower benefit scenario is relevant to the Commission's decisions. Under BGE's proposal it is ratepayers who will bear essentially all of the financial risk if actual benefits are much lower than projected in the business case and/or if actual costs are much higher than projected.

**Q. PLEASE EXPLAIN WHY ACTUAL BENEFITS ARE LIKELY TO BE LOWER THAN THOSE PROJECTED IN THE BUSINESS CASE.**

A. Actual benefits are likely to be at levels somewhere between those projected in the business case and those projected in the scenarios with lower TRC results. In other words it is likely that the actual future will be a composite of elements from three of the separate scenarios analyzed by Mr. Vahos. Those three are *Lower Projected PTR Participation, 50% Decrease in Projected Monetized Capacity Revenues,* and *Lower EE level*.

My expectation of a future with PTR participation and EE reductions lower than those projected in the business case is based upon the analyses presented the testimony of Ms. Brockway. She provides several reasons why the actual quantity of residential peak load reductions achieved each year for fifteen years is likely to be lower than the level projected in the business case. She also explains why the Company's projection of a 1% reduction in annual consumption from EE is not the most likely estimate.

My expectation of a future with lower than projected capacity revenues is based upon an analysis of capacity market fundamentals presented in Exhibit____ (JRH-6).

**Q. WHAT VALUE OF WHOLESALE CAPACITY DID THE COMPANY ASSUME AS THE BASIS FOR ITS PROJECTED BENEFITS FROM PEAK LOAD?**

A. The Company's business case projections of capacity revenue benefits are based upon its assumption regarding the value of capacity in the wholesale market operated by PJM for the zone in which BGE is located, i.e. SWMAAC, over the planning period. The Company basically assumes that a new gas-fired combustion turbine (CT) will be the marginal source of new capacity in that market and that, on average, the market price will clear at levels equal to the net cost of bringing such a unit into service, which is referred to as the net cost of new entry or 'net CONE'. For the planning year 2012 PJM set that value at approximately $176 per MW-day. (That value is equivalent to $64 per kw-year).

The Company's assumption that the market price of wholesale capacity will, on average, clear at the net CONE of a gas-fired CT is not based upon any analysis of the demand and supply factors that may affect the wholesale market for capacity in PJM over that period (Responses to OPCDR2-8 and 2-24). If the Company's assumption is incorrect, and the actual market value of capacity is much lower than the Company has assumed, the actual amounts of capacity revenue benefits will also be lower than it has projected.

**Q. WHAT MARKET FUNDAMENTALS MAY CAUSE THE MARKET PRICE OF WHOLESALE CAPACITY TO BE MUCH LESS THAN THE VALUE THE COMPANY HAS ASSUMED IN THE BUSINESS CASE?**

A. The market fundamentals that may cause the market price of wholesale capacity to be much less than net CONE of a gas-fired CT are low load growth, increased utilization of existing capacity due to reduction in transmission constraints and capacity additions from renewable resources driven by Renewable Portfolio Standards (RPS). I discuss each of those market fundamentals in Exhibit____(JRH-6). Those factors could combine to delay the need for additional new gas-fired CT capacity, or other conventional capacity by several years. Hence, those market fundamentals, and that delay, will tend to keep market prices for wholesale capacity below net CONE of a gas-fired CT over the planning period.

On the demand side, peak load in PJM is likely to grow more slowly in the future than it has in the past, even after the economy rebounds. Increased spending on energy efficiency and demand response, prior to any impacts of AMI investments, will contribute to lower growth in peak demand. On the supply side, new transmission projects will tend to reduce the constraints that currently limit the ability to access capacity located outside SWMAAC. Finally, new renewable energy resources are projected to come on-line in response to the renewable portfolio standards of various states.

Based upon those various factors it is reasonable to expect that market prices for wholesale capacity in PJM could be much less than the Company's assumed value. For example, wholesale market prices for SWMAAC from the most recent three auctions have averaged $139 per MW-day ($51 per kw-year), as compared to the Company's assumption of $176/MW-day. Moreover, the market prices in western PJM zones averaged $100/MW-day ($36 per kw-year), almost half of the Company's assumed long-term value. The prices from those zones indicate the potential levels of prices in a future with lower load growth and reduced transmission constraints.

**Q. HAVE YOU EXAMINED UTILITY PROJECTIONS OF THE MARKET VALUE OF AVOIDED CAPACITY IN OTHER AMI OR DEMAND RESPONSE FILINGS?**

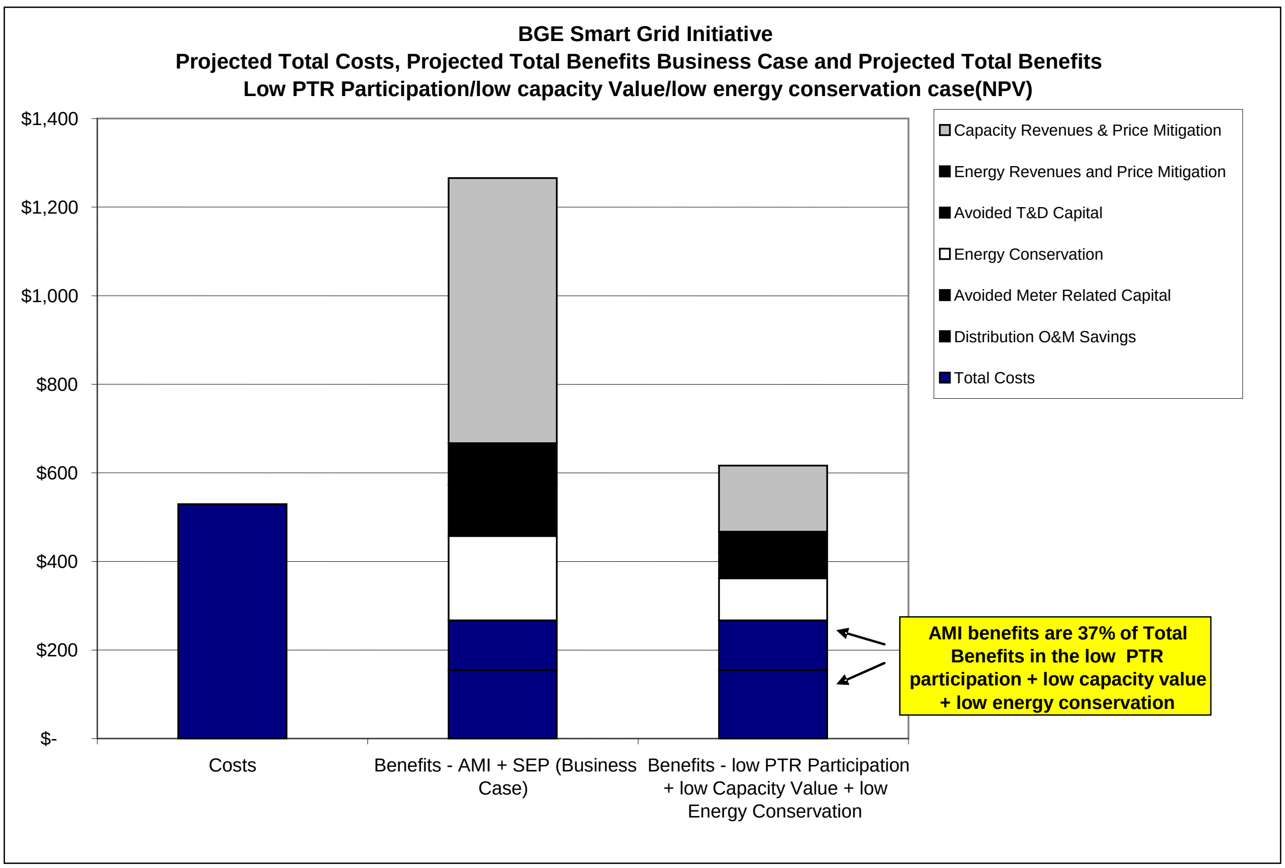
A. No. In other proceedings I have analyzed the projected timing and magnitude of capacity benefits that utilities expect from DR enabled by AMI. However, this is the first proceeding in which I have examined a utility's projection of the market value of avoided generating capacity it expects to receive for its peak load reductions. My decision to examine the projections of the market value of capacity was sparked by two events.

In May the base residual auction (BRA) for planning year 2012/2013 set the market value of capacity in the rest of PJM at $16 per Mw-day, equivalent to $6 per kw-yr. This is less than 10 percent of the $176 per MW-day that BGE assumes to receive for 15 years. I realize that the current demand and supply conditions in SWMAAC are different from the rest of PJM, but it does indicate the potential for market fundamentals to drive prices down.

In August a Synapse project team I managed completed a long-term projection of avoided capacity and energy costs in New England. That report projects that wholesale capacity costs in New England, which have been approximately $30 per kw-year, will be approximately $18 per kw-yr. That low long-term projected value is attributable to an over-supply of existing capacity, a projection of low load growth and a projection of substantial new renewable capacity driven by renewable portfolio standards. Again, I realize that the current demand and supply conditions in SWMAAC are different from those in New England, but our projection for New England does indicate the potential for market fundamentals to drive prices down.

**Q. WHAT IS THE IMPLICATION OF A LOW BENEFITS SCENARIO FOR THE SMART GRID INITIATIVE?**

A. The low benefits scenario that I have analyzed assumes 39% PTR participation, capacity market prices 50% of those in the business case and energy efficiency reductions of 0.6%. Under this scenario the Initiative has a TRC ratio of 1.4. The total benefits, by category, under this scenario are presented in the third bar of the chart below which is Exhibit JRH-7.



**Q. WHAT IS THE IMPLICATION OF A LOW BENEFITS SCENARIO FOR THE COMPANY?**

A. As noted earlier, this lower benefits scenario would not have any particular adverse implication for BGE. Under its proposed cost recovery approach the Company would make the same AMI investment and earn the same return on that investment as it would under the business case.

**Q. WHAT IS THE IMPLICATION OF A LOW BENEFITS SCENARIO FOR RATEPAYERS?**

A. This the lower benefits scenario has adverse implications for ratepayers. Ratepayers would have to rely heavily upon the Commission to ensure that the Company actually produced the projected benefits attributed to AMI and flowed those benefits through in its rates. As illustrated in Exhibit JRH-7, under this scenario AMI related benefits represent approximately 40% of the total benefits and are therefore much more important than under the business case.

**Q. IS THE POSSIBILITY THAT ACTUAL BENEFITS MAY BE LESS THAN IN THE BUSINESS CASE OFFSET BY BENEFITS THAT THE COMPANY HAS NOT QUANTIFED?**

A. No. Mr. Case refers to several categories of benefits he expects from the Initiative but that he has not quantified (Case Direct, p.6 and p.18). These categories include environmental benefits including reduced carbon emissions, support for significant expansion of renewable energy and development of electric vehicles, increased reductions from the PeakRewards program and increased energy conservation. The reference to these benefits implies that, if quantified, they would be material. However, until the Company actually quantifies each of these benefits in some manner, in physical terms if not in monetary terms, I recommend that the Commission not give them any weight.

The Company could have quantified the environmental benefits of the reductions in peak load and annual electricity consumption it is projecting, particularly reductions in physical quantities of carbon emissions. It is relatively straightforward to estimate the physical quantity of carbon reduced by applying a carbon emission co-efficient, e.g. tons of carbon per kWh, to the quantity of kWh reduced. The carbon emission coefficient can be estimated based on assumptions regarding the type and fuel of the generating units that are “on the margin” in peak and off-peak hours.

The ability of AMI and SEP to support significant expansion of renewable energy and development of electric vehicles are both also routinely highlighted. However, the Company needs to provide an analysis of whether similar support can be provided at less cost through other approaches. (Responses to OPCDR 2 – 22 and 2-23)

In response to OPCDR4-1 the Company states that smart meters will enable it to increase the operability of its load control switches and thereby increase the peak load reduction from this program. The Company has not quantified this benefit. Moreover, it is not clear that it would produce an incremental benefit in the near term, since PJM is apparently already compensating the Company for an agreed upon assumed quantity of peak load reduction from this program. That agreed upon assumption includes an assumed level of operability.

In that response the Company also identifies the potential benefit from achieving additional conservation benefits via in-home displays. First, the Company’s business case does not include costs for in-home displays. Second, in her Direct Testimony Ms.

Brockway indicates that there is considerable uncertainty regarding the projected levels of conservation that can actually be achieved on a sustained basis from in-home displays.

**Q. HAS BGE EVALUATED THE ADVANTAGES OF DELAYING THE DEPLOYMENT OF THE INITIATIVE?**

A. No. However, in response to OPCDR 2-3, BGE does give four reasons why it believes deployment should not be delayed. None of the four reasons stand up to scrutiny.

First, BGE states that a delay would jeopardize the ability to reduce costs to customers from the receipt of Department of Energy ("DOE') grant monies. This reason is not relevant because we expect that the Commission will know in October whether the DOE has awarded BGE a grant, and can take that fact into consideration when making a decision regarding delay.

BGE also states that a delay would postpone achievement of customer benefits from the Initiative and impede its progress towards achieving the EmPOWER Maryland peak reduction goals. Neither of these points is relevant if the reason the Commission was requiring a delay was its concern that the proposed deployment would not achieved those projected benefits and reductions at a reasonable cost. Finally, BGE states that a delay would defer the benefits of increased reliability. As discussed earlier, BGE has failed to quantify those purported benefits.

**Q. PLEASE SUMMARIZE YOUR CONCLUSION AND RECOMMENDATION REGARDING THE PROJECTED TOTAL BENEFITS AND COSTS OF BGE'S PROPOSED INITIATIVE.**

A. My general conclusion is that there is considerable uncertainty regarding the projected total benefits of the Initiative as well as some uncertainty regarding its projected costs. These uncertainties arise from the lack of long-term experience with the full-scale deployment of AMI and dynamic pricing such as the Smart Grid Initiative Company is proposing. In particular, over 60% of the projected total benefits hinge on an assumption that over 75% of residential customers will respond to the new Peak Time Rebate (PTR) on a sustained basis over 15 years, 2012 to 2027. Moreover, approximately 75% of that sub-set of projected benefits, or over 45% of total benefits, hinge on a second assumption that avoiding a kw of generating capacity will be worth $64 per year over 15 years. These uncertainties create a financial risk, i.e. the risk that actual benefits from the Initiative may prove to be substantially less the Company's projections. This financial risk is relevant to the Commission's decision regarding approval of the Company's request as well as to its decision regarding cost recovery.

Based upon that conclusion I recommend that the Commission take this financial risk into consideration when making its decision as to whether to approve or reject the Company's request. If the Commission does approve the Initiative, I recommend that it take this financial risk into consideration when deciding upon the method of cost recovery. In particular I recommend that the Commission hold the Company to its projected costs and its projection savings in distribution service operating costs.

**Q. DOES YOUR RECOMMENDATION APPLY EVEN IF BGE RECEIVES A DOE GRANT TO OFFSET THE PROJECTED COST OF THE INITIATIVE?**

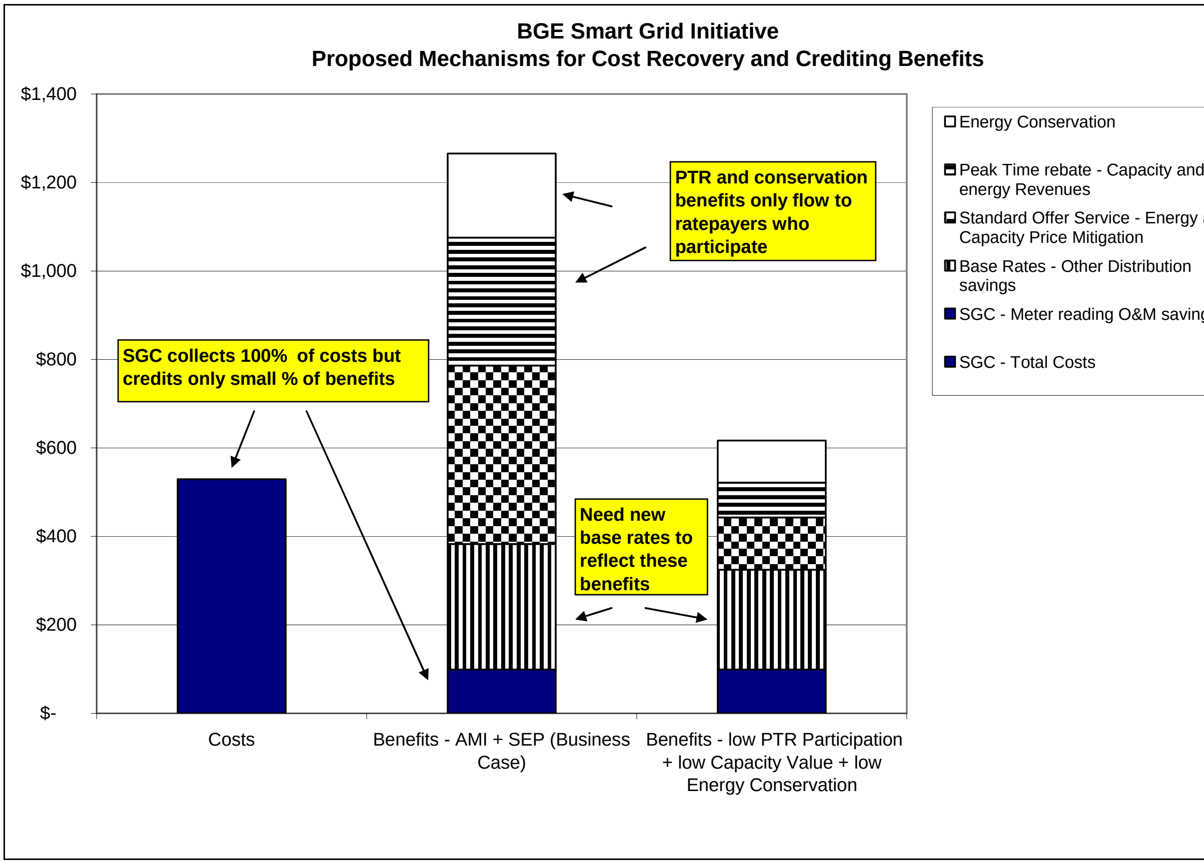
A. Yes. Even if BGE receives a DOE grant, there will still be a risk that actual benefits from the Initiative may prove to be substantially less the Company's projections. That risk will be lower, but a risk will still exist. The nature and amount of financial risk is relevant to the Commission's decision regarding approval of the Company's request as well as to its decision regarding cost recovery.

## V. CONCERNS REGARDING RATEMAKING ASPECTS OF THE COMPANY'S PROPOSED SURCHARGE MECHANISM

**Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL FOR RECOVERING THE COSTS OF THE INITIATIVE FROM RATEPAYERS AS WELL AS FOR CREDITING BENEFITS TO RATEPAYERS.**

A. The Company proposes to recover the Initiative's entire projected cost of $800 million from all rate classes, both electric and gas, through a new SGC that would operate independent of base rates. The Company proposes to flow savings in meter-reading expenses to ratepayers through the SGC. It expects the remaining projected benefits will flow to ratepayers through four other mechanisms - future changes in base rates, future changes in rates for Standard Offer Service due to the mitigation of wholesale prices, PTRs to ratepayers who reduce peak load in response to that pricing and energy conservation by ratepayers who respond to usage and pricing information provided by the Initiative. (Vahos Direct, p. 23 and responses to OPCDR2-4 and 2-5).

The amount that the Company proposes to recover via the SGC as well as the amount of benefits from the business case it expects will flow through each mechanism are presented in the chart below, which corresponds to the total costs and benefits presented in Exhibit___(JRH-7). The chart also shows how benefits will flow to ratepayers under a low benefits scenario. This chart is attached as page 1 of Exhibit___(JRH-8).




As indicated in the first column of the chart, the Company expects to recover all costs through the SGC. It proposes to flow only approximately 8% of the total projected benefits of the Initiative, the savings in meter-reading expenses, to ratepayers through the SGC. The remaining savings in distribution service related costs, representing 22% of the total projected benefits, would flow to ratepayers through future changes in base rates. The benefits of mitigating wholesale capacity and energy prices, approximately 32% of total projected benefits are expected to flow through to ratepayers via future changes in their rates for Standard Offer Service or supply from other load serving entities. Finally, PTR and conservation benefits, representing 38% of total projected benefits, will flow to ratepayers who reduce peak load and/or annual consumption in response to PTRs and/or usage and pricing information provided by the Initiative.

**Q. PLEASE COMMENT ON THE COMPANY'S PROPOSAL FOR FLOWING DISTRIBUTION SERVICE COST REDUCTIONS BACK TO RATEPAYERS.**

A. There are two basic problems with the Company's position.

First, the Company proposes to flow savings in distribution service O&M expenses, other than meter reading, back to customers via future changes in base rates. However, the Company has not made any commitment to make those changes by filing a general rate case within a specified period of time after completing the installation of AMI.

Second, the Company's rates for delivery service will actually decrease relative to current levels as a result of its Initiative. Instead, the Company's projections of avoided T&D and meter-related capital expenditures indicate that delivery rates will not increase as much as they may have otherwise done in the absence of the Initiative.

**Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL FOR RECOVERING THE COSTS OF THE INITIATIVE VIA ITS PROPOSED SGC.**

A. The Company is proposing to recover the costs of its Initiative outside of its regular base rates through a special cost recovery mechanism. It is proposing to begin recovering these costs in 2010 via a new tracker or rider, the SGC. The Company is also proposing to recover any costs associated with its PTR via the SGC. These proposals are described in the Direct Testimonies of Company witnesses Case in pages 20 to 28, Vahos in pages 12 to 27 and Manuel pages 11 to 14.

The Company is proposing to apply the SGC as a customer charge, i.e. in $ per meter per month. As such it would be an unavoidable monthly fixed charge. The SGC would apply to customers on gas service as well as on electric service, and would apparently continue indefinitely. (Responses to OPCDR2-13 and 2-16).

In order to recover AMI costs the SGC would collect the annual revenue requirements associated with the Initiative. The major components of these revenue requirements are depreciation and return on the un-depreciated amount each year. The SGC would also credit any savings in meter-related O&M expenses that the Company achieves each year.

In order to recover the costs of the PTR the SGC would collect the revenues used to fund the PTR's each year. It would also credit any capacity or energy revenues it received from PJM each year as compensation for the peak load reductions bid into PJM capacity and energy markets.

**Q. IS THE COMPANY PROPOSING TO SUBJECT THE SGC TO A CAP?**

A. No.

**Q. HOW DOES THE SGC COMPARE IN MAGNITUDE TO CURRENT RIDERS THAT ARE COLLECTING REVENUES TO FUND ENERGY EFFICIENCY AND LOAD RESPONSE?**

A. Currently the Company is collecting an electric efficiency rider of $0.00115 per kWh from residential customers, and a demand response service rider of $0.00064 per kWh (BGE electric rate riders 2 and 15). Those two riders total $0.00179. If the value of the proposed SGC in 2012 was expressed as a delivery charge, instead of a customer charge, it would be **CONF XXX CONF**, approximately **CONF XXX CONF** the combined amount of Riders 2 and 15.

**Q. WILL THE PROPOSED SGC INCREASE THE BILLS OF RESIDENTIAL CUSTOMERS?**

A. Yes. The proposed SGC will increase the delivery service component of bills. Of course, the Initiative does provide ratepayers the opportunity to offset those increases by reducing peak load in response to the PTR and/or reducing annual consumption in response to usage and pricing information provided by the Initiative.

The proposed SGC will increase the customer charges of residential electricity and gas service substantially. Those increased customer charges will, in turn, produce large increases in the bills of usage customers because the customer charge represents a significant portion of the bills of such customers. Residential customers who take both electric service and gas service will see increases in the customer charges of both services – a double hit!

The Smart Grid Charge for residential electric tariffs is projected to start at **CONF XXX CONF** per meter per month in 2010 and increase to **CONF XXX CONF** per meter per month in 2013. The Smart Grid Charge for residential gas tariffs is projected to start at **CONF XXX CONF** per meter per month in 2010 and increase to **CONF XXX CONF** per meter per month in 2013.

To illustrate the impacts of these increases I use values for 2012, the first year in which the Initiative is projected to be operational and the year with one of the highest projected SGC levels. These impacts are presented on pages 2 and 3 of Exhibit___ (JRH-8).

The impacts on customer charges of residential electricity and residential gas customers in 2012 range from **CONF XXX** to **XXX CONF.** Those increased customer charges translate into increases in annual bills. For residential electric service the bill increase in 2012 is **CONF XXX CONF** while for a combined residential electric and gas service customer the increase is **CONF XXX CONF** per year.

These increased customer charges can represent significant percentage increases in the bills of low use residential electricity and gas customers. For example, there would be a **CONF XXX CONF** impact on the bills of the approximately 10% customers who use less than 220 kWh per month and a **CONF XXX CONF** increase on the 30 percent of customers who use less than 530 kWh per month. (The bill distribution information underlying this estimate is taken from a July 2009 analysis provided in response to OPCDR1-13).

**Q. WILL THE INCREASES IN THE DELIVERY SERVICE COMPONENT OF ANNUAL BILLS FROM THE SGC BE OFFSET BY SAVINGS IN SUPPLY COSTS FROM THE PTR AND/OR BY THE PROJECTED MITIGATION OF PRICES FOR STANDARD OFFER SERVICE?**

A. No.

First, the Company is proposing to implement the SGC in 2010. Ratepayers will not have any opportunity to offset the increases in bills from the SGC in 2010 and 2011 since the Initiative, including PTRs, conservation and mitigation of wholesale capacity and energy prices will not be implemented until 2012. Second, the PTR and price mitigation benefits do not apply to the Company's over 630,000 gas service customers.

Third, electric service customers who are either unable or unwilling to respond to the PTR to a meaningful extent, for whatever reason, will not receive that benefit. The Company acknowledges that some portion of residential customers will not respond, as indicated in response OPCDR4-12.

Finally, the price of generation service for residential customers effective June 17, 2009 was 12.245 cents per kWh. I expect that prices in 2012 will be of a similar order of magnitude. The projected mitigation of wholesale capacity and peak energy prices is unlikely to translate into a discernable impact on those prices.

**Q. HAS THE COMPANY DEMONSTRATED THAT ITS PROPOSED SGC IS REASONABLE?**

A. No. The Company is proposing to recover a significant level of revenue requirements from all rate classes. The Company has not prepared a cost of service study to guide its allocation of revenue requirements among services and rate classes, nor has it used such a study and an analysis of bill impacts to guide its decisions regarding use of a charge per meter per month as opposed to a charge per kWh.

**Cost Allocation**

**Q. WHAT IS THE BASIS OF THE COMPANY'S PROPOSED ALLOCATION OF THESE COSTS AMONG SERVICES AND RATE CLASSES?**

A. The Company is proposing to allocate these costs between its electric and gas services using a "modified Massachusetts method". Within electric service it is proposing to allocate the costs among rate classes according to the contribution of each class to system-wide peak demand, referred to as Peak Load Contribution ('PLC'). It is proposing to allocate among gas rate classes according to number of customers. (Vahos Direct, p.26).

**Q. HAS THE COMPANY DEMONSTRATED THAT THE PROPOSED ALLOCATIONS AMONG ELECTRIC RATE CLASSES AND AMONG GAS RATE CLASSES ARE REASONABLE?**

A. No. Generally accepted ratemaking principles require that proposed revenue requirements of this magnitude and complexity be allocated among services and rate classes according to the results of a cost-of-service ('COS") study. For example, the Company's allocation implicitly assumes that the cost of a meter for a residential customer is identical to the cost of a meter for a C&I customer in one of the general service rate classes. (Response OPCDR 2-18). In fact, it is my understanding that the cost of smart meters will differ by the size and type of customer, and therefore meter costs should either be assigned by rate class or allocated using a cost-weighted allocation factor.

**Rate Design**

**Q. HAS THE COMPANY PROVIDED AN ANALYSIS TO SUPPORT ITS PROPOSAL TO APPLY THE SGC AS A CUSTOMER CHARGE RATHER THAN A DELIVERY OR DEMAND CHARGE?**

A. No. Again, fundamental ratemaking principles suggest that once the Company has determined the revenues to be collected from each service and rate class, it should use the results of its cost-of-service study plus an analysis of bill impacts to guide its decisions regarding the portion of the rate class revenue requirement to recover via an increase in the customer charge and the portion to recover via increase in the delivery and/or demand charge components of each tariff. For example, one could challenge the Company's proposal to recover its costs via customer charge on the grounds that the costs of the Initiative are, in reality, "caused" by the projected SEP benefits. Those benefits are a function of customer peak load reductions and/or annual consumption, and should therefore be recovered via the kWh charge, not the customer charge.

In addition, because the customer charge is unavoidable and because it has a disproportionate impact on low use customers within the residential rate classes, it is particularly important to assess any proposed increases in the customer charge according to the rate design principle of gradualism.

**Q. IF THE COMMISSION APPROVES AN SGC, SHOULD IT REQUIRE THE COMPANY TO APPLY IT AS A DELIVERY CHARGE UNTIL IT COMPLETES A COS AND ANALYSIS OF BILL IMPACTS?**

A. Yes. If the Commission allows the Company to impose an SGC, it should require the Company to apply it as a delivery charge until it can justify applying it as a customer charge. As a delivery charge the SGC will have less impact on bills of low usage customers and will give them the opportunity to avoid some portion of it.

**PTR**

**Q. IS THE COMPANY'S PROPOSAL TO RECOVER ITS PTR COSTS VIA THE SGC REASONABLE?**

A. No. As I noted, the Company is proposing to use the SGC to recover the costs of investing in AMI as well as the costs of offering a PTR. The problem is that these are fundamentally different types of expenditures: the AMI is a capital expenditure with a finite recovery period while the PTR is an operational expense that may continue indefinitely. If approved, I suggest that recovery of PTR costs be removed from the SGC and recovered via an existing rider, such as the PeakRewards program rider.

**Q. IS THE COMPANY'S PROPOSAL TO BASE ITS PTR ON NET CONE OF A GAS-FIRED CT RATHER THAN THE WHOLESALE MARKET VALUE OF CAPACITY REASONABLE?**

A. No. The Company is proposing to set its PTR based on net CONE of a gas-fired CT rather than the market value of wholesale capacity. However, the revenues it will receive from PJM will be based upon the wholesale market value of capacity. The Company proposes to have ratepayers fund any shortfall between the amount it gives out as PTRs and the revenues it receives from PJM. It proposes to collect those funds via the SGC.

The Company's proposed approach is not reasonable. Under that approach it will have to collect a significant amount from ratepayers to fund the PTRs in years in which actual revenues from PJM are well below net CONE of a gas-fired CT.

**Conclusions and Recommendations Regarding Proposed Ratemaking for Cost Recovery**

**Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING BGE'S PROPOSALS FOR RECOVERING THE COSTS OF THE INITIATIVE FROM RATEPAYERS AS WELL AS FOR CREDITING BENEFITS TO RATEPAYERS.**

A. The Company proposes to recover the Initiative's entire projected cost of $800 million from all rate classes, both electric and gas, through a new Smart Grid Charge (SGC) that would operate independent of base rates. The proposed SGC is expressed in $ per meter per month, i.e. it would be an unavoidable monthly fixed charge.

The Company proposes to flow approximately 8% of the projected benefits of the Initiative, the savings in meter-reading expenses, to ratepayers through the SGC. It expects the remaining 92% of the projected benefits to flow to ratepayers through four additional mechanisms - future changes in base rates, future changes in rates for Standard Offer Service due to the mitigation of wholesale prices, PTRs to ratepayers who reduce peak load in response to that pricing and energy conservation by ratepayers who respond to usage and pricing information provided by the Initiative.

The cost recovery aspects of the Company's proposed Initiative include the level of annual revenue requirements to be recovered, the allocation of those revenue requirements among rate classes and the design of the specific rates by rate class to recover those allocated revenue requirements. According to fundamental ratemaking principles one would expect to see the cost recovery aspects of an expenditure of this magnitude addressed in a general rate case. The Company's proposals are not guided by either a COS study or an analysis of bill impacts, and it is requesting recovery via surcharge, i.e. outside of base rates. The absence of these analyses is of particular concern since the Company's proposed SGC will increase customer charges of residential electric and gas customers by a significant amount, which in turn will lead to significant increases in the bills of low usage residential customers.

My general conclusion is that, as a basis for recovering expenditures of this magnitude and complexity, the Company should have prepared a cost-of-service ('COS") study to guide its allocation its proposed allocation of the Initiative's revenue requirements among rate classes. In addition, it should have used the results of that COS study and an analysis of bill impacts to guide its proposal to recover the revenue requirements allocated to residential customers via a monthly customer charge.

Based upon that conclusion I recommend that the Commission require the Company to present the results of a COS study and an analysis of bill impacts before approving recovery of any costs of the Initiative from residential customers via a customer charge, and only allow such recovery to continue for a limited period. In addition, I recommend that the Commission require the Company to file a general rate case no later than 2012 in order to re-set its base rates to reflect AMI related savings in its distribution service costs as well as to address the allocation of AMI-related revenue requirements and the design of rates to recover those revenue requirements.

Finally, if approved, I recommend that the Commission require the Company to move recovery of PTR costs from the SGC to an appropriate rider. In addition, I recommend that the Commission limit the amount the Company can collect from ratepayers to fund PTR costs in any year net of revenues it receives from PJM.

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.