ORDER NO. 83531

IN THE MATTER OF THE APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR AUTHORIZATION TO DEPLOY A SMART GRID INITIATIVE AND TO ESTABLISH A SURCHARGE FOR THE RECOVERY OF COST	* * * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9208

To: The Parties of Record and Interested Persons

In this Order, we grant Baltimore Gas and Electric Company's ("BGE" or the "Company") request to proceed with deployment of its Advanced Metering Infrastructure ("AMI") Initiative (the "Initiative"), subject to the conditions we set forth below. We acknowledge and appreciate that BGE revised its Initial Proposal and amended it further during this second round of hearings – the Company obviously attempted, in good faith, to address the issues that precluded us from approving the Initiative before. Although BGE's revisions do not entirely cure the concerns that caused us to deny approval the first time, we have heard and believe we have addressed BGE's countervailing concerns, and have defined a set of conditions on which we can approve the implementation of the project.

Our conditions, which relate primarily to the way in which BGE would recover the costs of the Initiative from its customers, bring the program in line with the principles we articulated in Order No. 83410, and ensure that the Initiative will be cost-effective for ratepayers, as Public Utility Companies ("PUC") Article § 7-211 requires. We also will review the progress of the Initiative periodically against metrics we describe below, and which we direct the parties to develop and submit for approval. As conditioned, the Initiative is in the public interest, and offers BGE the opportunity to deliver potentially significant benefits to its customers while taking advantage of available federal money to pay down the cost.

We recognize that the terms we describe below differ from what BGE has offered, and that BGE has represented that it will not proceed with the Initiative if we do not allow cost recovery through a surcharge, or "tracker." Whether or not to go forward is, obviously, BGE's decision. The conditions set forth below are consistent with established ratemaking principles for large-scale infrastructure projects in Maryland, and are fully supported by the record in this case. The conditions are, we believe, fair to the Company, and provide assurances of an appropriate cost recovery while mitigating the risk to ratepayers and allocating the risk more fairly between the Company and its customers. As now structured, we believe that this Initiative would be a win-win proposition for BGE, its customers and our State, and we hope that BGE will choose to proceed.

I. Background and Procedural History

On June 21, 2010, after a comprehensive review of BGE's initial request for authorization to deploy a Smart Grid Initiative (the "Initial Proposal"), we issued Order No. 83410, which denied BGE's request to proceed with the Initial Proposal. The Order describes the history of this case, BGE's Initial Proposal and our reasoning in detail, and we will not repeat that discussion here at any length. In summary, though, we denied BGE's Initial Proposal based on four primary concerns: (1) we held that cost recovery through a surcharge or "tracker" mechanism was inappropriate;[1] (2) we were unwilling to impose mandatory "time of use" ("TOU") rates on all customers, as the Initial Proposal required;[2] (3) we were concerned that the Initial Proposal did not contain a concrete and detailed consumer education plan, an element we found would be critical to the success of the Initiative;[3] and (4) we disagreed that BGE's customers should bear all of the risks inherent in the underlying technology[4] and the risks that the benefits critical to the business case would not materialize.[5] Based on these concerns, we found the Initiative untenable, but we "invite[d] BGE to submit an alternative proposal that mitigates and more fairly allocates between the Company and its customers the risk that the reality of this project will not reflect the projections BGE has provided to this Commission."[6]

BGE informed the United States Department of Energy ("DOE"), which had awarded the Company $200 million under the American Recovery and Reinvestment Act of 2009 for the Initiative and other projects, of our decision in Order No. 83410 the next day.[7] According to a letter BGE received from DOE on June 30, 2010, DOE and BGE met "to review the impact of the Maryland PSC decision on the project."[8] The letter stated that DOE understood that BGE was "reviewing the Commission's Order and evaluating options on how to proceed." DOE also understood that BGE "will not go forward with the Smart Grid deployment absent cost-recovery approval by the PSC."[9] DOE also stated that it "will render a final decision on whether to proceed with, modify,

[1] Order No. 83410 at 27-31.
[2] *Id*. at 31-33.
[3] *Id*. at 33-34.
[4] *Id*. at 35-41.
[5] *Id*. at 44-53.
[6] *Id*. at 53-54.
[7] Letter from D. Williams to M. Case, June 30, 2010 (Attachment 1 to BGE's Application for Rehearing).
[8] *Id*.
[9] *Id*.

or terminate BG&E's project by July 30, 2010," and that "[o]ur decision will be based on the facts available to us at the time."[10]

Late in the day on Monday, July 12, 2010, BGE filed its Application for Rehearing of Order No. 83410 ("Application"), which contained the Revised Proposal, and asked for a decision from us by July 30, 2010.[11] We issued a Notice of Status Conference on Tuesday, July 13, 2010[12] and held a Status Conference on Wednesday, July 14, 2010. As it had in connection with its Initial Proposal,[13] BGE asked us during the Status Conference to receive comments and schedule a legislative-style hearing rather than holding an evidentiary hearing. We decided that, like the Initial Proposal, the Revised Proposal required sworn testimony and an opportunity for cross-examination. After hearing from the parties, we ordered an expedited schedule from the bench: discovery started immediately; deadlines were shortened; we scheduled two rounds of testimony; and we set a two-day evidentiary hearing on August 5-6, 2010.[14]

The schedule we adopted did not put this case in line for a decision by July 30, 2010. We did this not to convey any disrespect for DOE's deadlines or process, but to ensure a fair and thorough review of BGE's Revised Proposal. As we stated at the July 13th Status Conference, we understand and have always assumed that DOE would make the decisions it needed to make on its timetables, and we do not expect DOE to wait for us. We also sent a letter to DOE on July 16, 2010 explaining the status of this proceeding and our intention to rule as quickly as possible:

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[10] *Id*.
[11] Item No. 61 (July 12, 2010). We discuss the terms of the Revised Proposal below.
[12] Item No. 62 (July 13, 2010).
[13] Order No. 83410 at 16.
[14] We also issued a Notice of Procedural Schedule memorializing the dates. *See* Item No. 66 (July 16, 2010).

> In light of the Department's statement that it will "render a final decision on whether to proceed with, modify or terminate BGE's project by July 30, 2010" regarding the award of American Reinvestment and Recovery Act funding in support of BGE's AMI Initiative, we convened an immediate status conference. After hearing from the parties in this contested case, we established an expedited schedule to review BGE's revised AMI proposal. The Scheduling Order initiated immediate discovery with accelerated response deadlines, ordered direct testimony by noon on July 19 and response testimony by noon on August 2, and established evidentiary hearings for August 5 and 6. Although this schedule does not conclude by the Department's July 30 decision date, we hope the Department can appreciate the Commission's responsibility to evaluate this significant proposal on a fair and appropriate record.
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> The Commission intends to rule promptly after the hearing concludes. I cannot comment on the merits of the proposal or foreshadow the Commission's decision, but I can assure you that the proposal will receive an expedited, but still thorough, review.[15]

DOE responded on July 30, 2010 with a letter stating that "in view of the progress made on this front and the positive steps taken by BG&E and the Commission since July 21, DOE will not render a decision on whether to proceed with, modify, or terminate BG&E's project until August 16, 2010."[16] The Department again made clear that its "decision will be based on the facts available to [it] at the time."[17]

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[15] Letter from D. Nazarian to D. Williams, July 16, 2010, Item No. 70.
[16] Letter D. Williams to D. Nazarian, July 30, 2010, Item No. 73.
[17] *Id*.

BGE submitted written testimony on Monday, July 19, 2010[18] and Commission Staff,[19] the Office of People's Counsel ("OPC"),[20] AARP[21] and the Maryland Energy Administration ("MEA")[22] submitted written testimony on Monday, August 2, 2010. We held two long days and evenings of evidentiary hearings on August 5 and 6, 2010, during which all of the witnesses appeared, were subject to cross-examination and answered questions from the Commission. Just after we completed the witness testimony on the evening of August 6, BGE submitted two additional revisions to its Revised Proposal.[23] BGE witness Mark Case took the stand again to explain these revisions, and we scheduled a follow-up conference for Monday, August 9, 2010, to allow the other parties an opportunity to consult with their witnesses and prepare a response to BGE's proposed revisions to the Revised Proposal. We then heard from all of the parties,[24] and received into evidence responses to new data requests relating to BGE's amendments to the Revised Proposal.[25] Based on the parties' representations of their positions, and the need to issue this Order in time for DOE to meet its August 16, 2010 decision deadline, we

[18] BGE submitted the Testimony of Mark Case in Support of Application for Rehearing ("Case Rhg. Test."). We view this stage of the proceeding as requiring consideration of a revised proposal from BGE rather than a mere request for rehearing. Although BGE has asked us to reconsider certain elements of our decision in Order No. 83410, it also has amended elements of the original proposal. Nevertheless, in order to distinguish the testimony we received in this later round from the testimony we received earlier from many of these same witnesses, we will abbreviate here using the "rehearing" reference in the titles of the new testimony.

[19] Staff submitted the Rehearing Testimony of Crissy Godfrey ("Godfrey Rhg. Test."), Daniel J. Hurley ("Hurley Rhg. Test.") and Randy Allen ("Allen Rhg. Test.").

[20] OPC submitted the Reply Testimony of J. Richard Hornby ("Hornby Rhg. Test."), Nancy Brockway ("Brockway Rhg. Test.") and David J. Effron ("Effron Rhg. Test.").

[21] AARP submitted the Testimony of Barbara Alexander ("Alexander Rhg. Test.").

[22] MEA submitted the Direct Testimony of Fred Jennings ("Jennings Rhg. Test.").

[23] BGE Exhibit 21.

[24] Tr. 6-16 (August 9, 2010).

[25] *See* Tr. 24-26 (August 9, 2010) (admitting Staff Exs. 17-19).

decided not to schedule oral argument or order post-hearing briefs, and no party objected.[26]

II. The Revised Proposal

A. The Company's Revisions

BGE's Application revises its Initial Proposal in response to our decision in Order No. 83410. The technological fundamentals of the Initial Proposal remain intact – the Revised Proposal makes no changes to the physical AMI buildout, the meters BGE would install, the communications infrastructure they would utilize, the nature or timing of the usage information available to customers after installation, or the components of the projected costs or benefits.[27] The schedule for deploying the AMI system has evolved, in light of these proceedings, but it remains a two-stage, 14-year project:[28] (1) a deployment period, estimated to take four years (2011-14), during which the Company would install the new "smart" meters and the systems enabling them; and (2) a post-deployment period, approximately ten years, during which the Company would operate and maintain the system.[29] BGE proposes to begin installing meters in October 2011[30] and to install approximately 3,000 new meters per day.[31] BGE projects that it would have approximately 60% of customers' meters installed when the Peak Time Rebate program would begin in the summer of 2013,[32] and 80% installed in time for the summer of 2014.[33]

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[26] Tr. 26-29 (August 9, 2010).
[27] *See* Order No. 83410 at 17-26 for a full description of the technological elements of the Initiative.
[28] Tr. 2163 (August 6, 2010) (Case).
[29] *Id.*; Application at 7-8.
[30] Case Rhg. Test. at 27.
[31] *Id*. at 19.
[32] Tr. 1727 (August 5, 2010) (Case).
[33] Tr. 1517 (August 5, 2010) (Case).

BGE claims that the Commission's decision not to approve the Initial Proposal rests largely on "misunderstandings" about the costs and benefits the Initial Proposal offered,[34] but the Application modified the Company's Initial Proposal in four major respects:

First, notwithstanding our holding that "we will not authorize cost recovery for any approved 'smart grid' or AMI project through a surcharge,"[35] BGE asks us to reconsider that decision and approve a "hybrid" tracker mechanism. BGE would recover approximately 25% of the project costs through a surcharge that would begin in January 2011 and continue until the effective date of the outcome of a base rate case following full AMI deployment.[36] The tracker would include all categories of costs for the Initiative except for the payment of the Peak Time Rebates, and would collect approximately $160 million of those costs, a figure which is net of realized meter reading savings.[37] From that point on, BGE would recover the remaining initial deployment costs and post-deployment costs in base rates.[38] BGE withdrew its request for a performance incentive and agreed to recover its tracker on a volumetric basis rather than a flat customer charge.[39] BGE proposes that the tracker be re-set annually and to "conduct ongoing, semi-annual program reviews to provide appropriate assurance and oversight on behalf of the consumer."[40]

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[34] Application at 2.
[35] Order No. 83410 at 30; *see also id*. at 27-31.
[36] Application at 7-10; Case Rhg. Test. at 3-9; Hearing Transcript ("Tr.") at 1495, 1513 (August 5, 2010) (Case).
[37] Tr. at 1565-68 (August 5, 2010) (Case). BGE proposed a Smart Energy Pricing Rider – a mechanism that would offset the costs of Peak Time Rebate payments with the capacity and energy revenues obtained in the wholesale markets.
[38] Application at 7-8.
[39] Application at 8.
[40] *Id*.

As it had during the initial round of this case,[41] BGE stated in its pre-hearing filings that "a regulatory asset presents an unacceptable risk"[42] and that "we know that we cannot go forward with the deployment of Smart Grid through regulatory assets or conventional ratemaking."[43] BGE argues that "a regulatory asset, for this type of project, is harmful both to customers and investors, and as such is unworkable for Smart Grid."[44] By deferring recovery through a regulatory asset, BGE contends, customers have to pay additional carrying costs, and risk rate spikes when the costs of the project are incorporated into rates.[45] Moreover, "given the circumstances, a regulatory asset of this magnitude is simply too risky, and the delay in cash flow during the deferral period also adversely affects BGE's credit metrics."[46] Mr. Case also testified during the hearing that the Company could face an earnings loss, depending on how a regulatory asset was structured,[47] and that "unless the regulatory asset were structured in what I think a very unusual way, the company would not be able to recover its costs, would not be able to earn its authorized return."[48]

When asked during the hearing whether denial of the tracker as proposed was a deal-breaker, the Company reiterated that it was:

> Q. [Mr. Hurson]: Did your team consider applying – asking for a tracker for less than a four-year period?

[41] *See* Order No. 83410 at 3-4 and n.5, 27 and n.113.
[42] Application at 7.
[43] Application at 26; *see also* Case Rhg. Test. at 8-9 ("These concerns and adverse impacts are in addition to the previously described harms to customers under a regulatory asset approach, and are intended to clarify why *BGE could not move forward under such an approach* and why it is not best for customers.") (emphasis added).
[44] Case Rhg. Test. at 6.
[45] *Id*. at 7.
[46] *Id*.
[47] Tr. 1523-26 (August 5, 2010) (Case).
[48] Tr. 1609-10 (August 5, 2010) (Case).

> A. [Mr. Case] No. We did not. Quite frankly, we're concerned about the level of risk, and I know different parties have different views, but we are already at a level of risk that is at our tipping point, I would say. From our standpoint we will incur financial risks, regulatory risks, reputational risks. We're investing a large sum of dollars that represents a very large increase in our normal level of capital expenditures. We felt anything less than a tracker in effect for the full deployment period would not work.
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> Q. As you sit here today, this Commission says BGE [,we] will approve this proposal, but we're only going to give a tracker for two years, do you have an answer as to whether you would move forward with this?
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> A. I think we would not.
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> Q. How about three years?
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> A. I think we would not.
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> Q. You think you're at your minimum right now?
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> A. That is correct. We put a lot of thought into it. Three weeks went by between the date of the order and the – we accelerated even that as much as we could knowing that the DOE timeline was compressed. We really did get to, in our application for rehearing, as much movement in that direction for cost recovery as we felt like we could possibly live with.[49]

The fact that 11 other utilities have approved some form of tracker mechanism for recovering at least some portion of AMI costs "demonstrates," according to BGE, "that Commissions have recognized that Smart Grid represents an extraordinary investment over a short period of time, and appropriate financing mechanisms are required."[50] But Mr. Case notes elsewhere in his testimony that "26 utilities in 15 states … have begun

[49] Tr. 1495-96 (August 5, 2010); *see also id.* at 1762 ("CHAIRMAN NAZARIAN: If we put out an order next Monday that says we'll approve this project but there's going to be some kind of recovery other than a tracker, the Department of Energy would be fine with that, BGE will say no, sorry, no deal." MR. CASE: That's correct.").
[50] Case Rhg. Test. at 6 and n.1; *see also* Application at 10 and n.12 (listing utilities with some form of approved trackers).

deployment of Smart Grid systems,"[51] which suggests that tracker mechanisms have been approved in fewer than half of the other deployments.

Second, BGE withdrew the portion of its Initial Proposal that would have required all customers to move into a Time of Use ("TOU") rate structure.[52] BGE argues that we misunderstood its position in the course of our earlier decision, that we could have approved the Initial Proposal without mandatory TOU rates, and that its business case never depended on them.[53] Nevertheless, BGE says that TOU rates are "not essential for this project," and the Company proposes to allow customers to opt into TOU rates on a voluntary basis.[54] Indeed, BGE now "believe[s it] can do more to promote the benefits of TOU rates on an optional basis."[55] And because BGE's original business case did not include benefits from the operation of mandatory TOU rates, the Company did not need to revise its new business case to reflect this change.[56]

Third, BGE submitted a "Smart Grid Consumer Education and Communication Plan" along with its Application.[57] BGE says that the Company "has been working on this matter for some time" and "did not know that the Commission wanted to see the plan until it issued its Order."[58] The Company characterized the plan as a "framework,"[59] not as a finished product, and expects that "the plan will be modified over time based on experience."[60] BGE also "welcomes suggestions,"[61] and is willing to participate in an

[51] Case Rhg. Test. at 15.
[52] Application at 11, Case Rhg.Test. at 9-11.
[53] *Id*.
[54] *Id*.
[55] Application at 22.
[56] Case Rhg. Test at 10.
[57] Application at 20 and Attachment 2, Case Rhg. Test. at 11-12.
[58] Application at 3.
[59] Tr. 1713 (August 5, 2010) (Case).
[60] Application at 20.
[61] *Id*.

ongoing work group process and periodic program reviews before the Commission.[62] The Company's revised business case budgets approximately $66 million for communications and consumer education costs over the life of the program,[63] about half of which would be spent during the four-year initial deployment period.[64]

Fourth, in response to our concerns about the appropriate allocation of the risk of this project between the Company and customers, BGE argues that its first three changes "go a long way to address concerns with regard to risk mitigation."[65] BGE cites its willingness to adopt a 10-year depreciation period and to appear for semi-annual reviews of the project during the deployment period as additional concessions that mitigate risk to ratepayers.[66] Ultimately, though, BGE argues that "100% of the benefits from Smart Grid under our proposal are set to flow through to the benefit of customers," and that BGE "simply seeks to recover its investment at the authorized rate of return for an initiative that provides a significant level of customer savings and reliability and service quality benefits."[67]

At the hearing, BGE described 15 steps it has taken (both before and after Order No. 83410) in connection with this Initiative that, in its view, mitigate the risks to its customers:

> Q. [Ms. Curry] OPC Witness Brockway and AARP Witness Alexander allege that there have been no changes to BGE's original proposal to mitigate and allocate risk to customers. How do you respond to that?

[62] Tr. 1497-99 (August 5, 2010) (Case).
[63] Tr. 1621-23 (August 5, 2010) (Case). This includes the cost of notifying customers of impending critical peak days. BGE Ex. 19.
[64] BGE Ex. 19; Tr. 2193 (August 6, 2010) (Case).
[65] Application at 23; *see also* Case Rhg. Test. at 14.
[66] Application at 23.
[67] Case Rhg. Test. at 15.

A. [Mr. Case] We tried to be as responsive to the Commission's concerns that were articulated in the order. We think about risk mitigation, we actually think that's one of the hallmarks that does differentiate our proposal versus many utilities' Smart Grid proposals. In total we think there are 15 ways that we are mitigating risk for BGE customers.

One is the hybrid cost recovery, so only 25 percent of the costs are being recovered through a tracker, the much larger portion, 75 percent of the project costs get recovered through traditional base rate cases.

Second is the delay of the tracker until 2011. Even where it begins in 2011, if this were approved, the rate is 7 cents per month, and that's after the rate in 2010, because we are already seeing a benefit in 2010. We've lowered the PeakRewards surcharge by 16 cents a month in 2010. If you count this as year zero or year 1, there's a 16-cent a month benefit. In 2011 there would be a 7-cent charge.

Third is moving to a 10-year depreciable life for the Smart Grid assets. Partially, and this was Staff's proposal, the Commission seemed to endorse it, we're supportive of that as well, what that does is decrease the risk that you would not have fully recovered the cost of this project potentially before an early obsolescence risk would come in. A second benefit is that it lowers the financing charges by more than 80 million dollars and lowers the cost to customers. Also we truncated the analysis period from a 15-year post-deployment, measured benefit for 15 years, we truncated it to 10 years. It's made it a more conservative business case.

Fourth is we've moved to a volumetric rate for cost recovery such that lower usage customers will pay a lower cost of the project.

Fifth, we've improved the alignment of cost and benefit. There are four major streams of benefits that customers will receive even during the deployment period when we propose to have the cost recovery tracker in place.

Sixth is the elimination of the shareholder incentive tied to achieving demand reductions.

Seven is the elimination of mandatory time [of use rates].

Eight is the development of a comprehensive customer education and communications plan which does in fact look at the experiences of other utilities that are before us in rolling out their Smart Grid projects and the lessons learned.

Nine is we tried to clarify the many conservative assumptions we incorporated into the business case. Including many benefit streams that we didn't quantify at all. We acknowledged they're there but we didn't put a number to them. We also conducted many sensitivity analyses to show the business case is robust under a wide variety of assumptions.

Tenth is operational savings. I mentioned before, they cover about 75 percent of the project cost. We had built in the largest component of operational savings, which is the reduction in meter reading costs, we built that in as a direct real-time reduction to the tracker, not as wait for a future rate case. It's immediate, as we reduce meter reading costs, we pass that on real-time to customers.

Eleven is that unlike many other states that did not conduct pilots of their customers to see how they would respond, we've had that benefit, we've had the benefit of real BGE customers sharing their experiences, what they liked and what they didn't like and observing what demand levels they were willing to reduce. We did it in 2008 and two years since to demonstrate the persistence of that.

Twelve, and I'm running down to the end, we tried to clarify and update the status of deployments throughout the U.S. and elsewhere globally to show that AMI technology is in fact proven, working, the interval data is coming in day after day and being used to bill customers in a very accurate manner, I would add.

Thirteen is that we have worked aggressively in developing a contract with our AMI provider, Silver Springs Networks, to develop a contract that has a number of performance clauses and other provisions to help ensure successful delivery of the project.

Fourteen is the proposed, what we consider to be a very regular ongoing process for review of the Smart Grid

> deployment in terms of the costs and benefits and also the direction of the project and allowing ample opportunity for adjustments along the way.
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> Then last, and to me this is the most compelling of all of the risk mitigation factors, is we went out and competitively sought a grant from the Department of Energy to help offset the costs, and out of 500 applications, we were selected with five other utilities to receive the top award in the country of $200 million. That $200 million reduces the revenue requirements over time by $350 million. So it has a compounding effect. For a residential customer it lowers of cost of this project by 79 percent. So if I think about how do you mitigate the risk to customers, to me that is one of the most exceptional forms of this mitigation.
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> I guess the last thing I would say about risk mitigation is at the end of the day, from our perspective, there is no free lunch. If we choose not to go forward with Smart Grid because we consider it a risk too high or any other reason, what we're really deciding is to go forward and procure other forms of power at a more expensive cost. There is no zero solution. We've got to do one or the other. We can reduce the demand or we can procure the capacity and energy, and from our perspective it's a clear winner to go with reduction in demand.[68]

BGE acknowledges, however, that the Company's response was designed primarily to mitigate risks, rather than to allocate them.[69] And, indeed, the Company does not believe it should share in the risk:

> COMMISSIONER GOLDSMITH: You mentioned two things. You mentioned the company's good faith, and then you also mentioned whether or not [it is] a successful or an effective project. Putting aside the good faith. If three or four years from now it turns out that the net benefit to BGE customers is nowhere close to what it is that BGE projects it will be if it deploys AMI and implements its programs. Do you believe it would be appropriate to condition any portion of the company's cost recovery on some minimum level or some level of performance of the project; in other

[68] Tr. 1487-92 (August 5, 2010) (Case).
[69] Tr. 1589.

> words, … if the benefits come nowhere close to the projections that the company has made, should the company's cost recovery be predicated in any part on the performance of the project overall?
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> MR. CASE: I can't ignore the first part of that question is did we operate in good faith. Did we operate with taking advantage of all the things reasonably available to us to make the project successful. If the answer to that first part of the question was yes, then I do not believe the company should have disallowance, not be able to recover its costs so long as we operated prudently and in good faith.
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> The regulatory construct for a utility set up so that if you do everything in a reasonable manner, you're allowed to earn Commission-authorized reasonable return on the investment you've made. Under a construct that you may be considering where we are at risk for how well, how much customers choose to respond to the price incentives that we make available to them, I would see no reason why the company would want to make such an investment.
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> If PeakRewards, if the recovery of PeakRewards were conditioned that you've got to get 40 percent of your customers to sign up, if only 30 percent sign up then you're subject to not being allowed to recover the cost, we would never want to make that type of investment.[70]

As part of Mr. Case's pre-filed testimony, BGE also updated the business case supporting the Revised Proposal[71] and provided updated bill impact estimates.[72] BGE contends that the Initiative remains cost-effective, as measured by the Total Resource Cost ("TRC") test,[73] even if one were to include the costs of legacy meters, a new billing system, in-home display devices or additional consumer education beyond budgeted amounts in the calculation, which we believe are all appropriate costs to consider.[74] But BGE acknowledges, as it must, that the Initiative is not cost-effective if we consider the

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[70] Tr. 1605-07 (August 5, 2010).
[71] Case Rhg. Test. at 23-28.
[72] *Id*. at 29-30; *see also* BGE Ex. 20.
[73] Case Rhg. Test. at 28.
[74] *Id*. at 25-26.

operational savings alone – BGE projects those savings to recoup only 75% of the cost of the project.[75]

In order to qualify ultimately as cost-effective, then, the record is undisputed that the Initiative must deliver *some* measure of supply-side savings. BGE's projections of customer supply-side savings far exceed the difference between the cost of the project and the operational benefits, hence its TRC projections of 4.4 (on a nominal basis) and 3.7 (on a present value basis).[76] Despite this considerable margin of error, the Company expects full cost recovery, with no risks or contingencies, whether or not the benefits materialize.[77]

B. Responses to the Revised Proposal

1. <u>AARP</u>

AARP "continue[s] to recommend that the Commission find the AMI proposal as submitted by BGE will expose customers to significant risks and that the costs cannot be justified based on BGE's estimated benefits that it states will occur over the 10-year period of its analysis of costs and benefits."[78] Although AARP welcomes the elimination of mandatory TOU pricing, Ms. Alexander contends that the Revised Proposal has changed little from the Proposal we denied in Order No. 83410,[79] and that we should deny approval again.

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[75] *See, e.g.*, Tr. 1743 (August 5, 2010) (Case) ("CHAIRMAN NAZARIAN: The operational benefits, the firing [of] the meter readers, the tangible operational efficiency benefits of building this gets you 75 percent of your cost back, according to what you said before, right? MR. CASE: Yes. CHAIRMAN NAZARIAN: So it's not cost-effective on that basis, is it? MR. CASE: No.").
[76] Case Rhg. Test. at 28.
[77] Tr. 1613 (August 5, 2010) ("COMMISSIONER BRENNER: What about if … performance standards are not met at the time of review, whatever the forum for that review, whether it be semi-annual presentation and discussion and consideration by us or in a larger case and the performance metrics can be used to say not yet to get recovery because you haven't met the standards. MR. CASE: It's untenable.").
[78] Alexander Rhg. Test. at 2.
[79] *Id*. at 1-3.

Ms. Alexander focused her testimony primarily on cost recovery and BGE's consumer education plan. She compared BGE's Revised Proposal to AMI rollouts in a number of other states,[80] many of which contain provisions that guarantee operational cost savings,[81] cap the costs that would be deemed prudent,[82] or require the utility to demonstrate savings as a condition of cost recovery.[83] And she discussed the Delaware Public Service Commission's order approving Delmarva Power & Light Company's ("DPL") AMI program, which deferred *any* evaluation of cost recovery to a future base rate case – it permitted DPL to "establish a regulatory asset to cover recovery of and on the appropriate operating costs associated with deployment of Advanced Metering Infrastructure and demand response equipment," but left "[t]he Commission, Staff, and other parties… free to challenge the level or any other aspects of the asset's recovery in rates when Delmarva seeks recovery of the regulatory asset in base rates."[84] Indeed, the Delaware Commission "may wish to consider an appropriately valued regulatory asset for advanced metering infrastructure investment consistent with the matching principle *giving consideration to both costs and savings in the context of its next base rate case proceeding*."[85] In contrast, Ms. Alexander argues, BGE's proposed method of cost recovery provides no protection to customers – BGE would not be required to bear any burden of proving benefits to consumers or even to guarantee operational savings.[86] Accordingly, she recommends "that BGE be required to seek cost recovery in a future

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[80] Her testimony mentions, at various times, programs in California, Michigan, Maine, the District of Columbia, Oklahoma, Nevada and Delaware.
[81] *Id*. at 11 (discussing Southern California Edison program), 14 (Oklahoma).
[82] *Id*. at 14 (Oklahoma).
[83] *Id*. at 12 (Delaware), 13-14 (Nevada)
[84] *Id*. at 12 (quoting Order No. 7420, Delaware PSC Docket No. 07-28 and PSC Regulation Docket No. 59 (September 16, 2008), at 5-6).
[85] *Id*. (emphasis added).
[86] *Id*. at 2, 10-11, 16-19.

base rate case in which it must document that the estimated benefits have in fact occurred and some portion of its cost recovery is required to be at risk for the failure to deliver the estimated benefits, both for distribution and generation supply benefits."[87]

With regard to consumer education, Ms. Alexander contends that BGE's plan lacks specificity, that our accelerated proceeding did not provide a sufficient opportunity to review it, and that "[m]ost importantly, BGE's materials do not include proposed metrics and performance standards that would govern BGE's outreach and educational initiatives and its recovery of those additional costs."[88] She recommends that we "undertake a professional evaluation of the AMI deployment experiences in California and Texas to determine the lessons learned and best practices that should be reflected in any future consumer education plan developed by BGE."[89] But even without the benefit of much time to review the Revised Proposal, Ms. Alexander identified a "significant defect in BGE's approach": the absence in the consumer education plan of "any proposed metrics to actually measure customer understanding and response to future outreach and educational messages."[90] She recommends that we require BGE to track and report on a variety of measures, including customer understanding of the AMI project, customer complaints regarding installation, customer complaints about their bills, customer understanding of the costs of the Initiative, customer participation in Peak Time

[87] *Id*. at 18. Ms. Alexander also contends that BGE has not eliminated from its business case cost savings relating to remote disconnections for non-payment that would violate current Commission regulations, and that the Revised Proposal fails to consider fully the needs of elderly, low-income and vulnerable populations or alternative means of achieving demand reductions. *Id*. at 2-3, 19-28. We note that we have not approved any exemption from our regulations concerning termination of service for non-payment, and that nothing in this Order should be construed as changing this Commission's policies or regulations regarding termination of service for non-payment.
[88] *Id.* at 3, 28-32.
[89] *Id*. at 29.
[90] *Id*. at 30.

Rebates, and "hits" on BGE's web portal.[91] She also recommends that we link BGE's performance against these metrics or performance standards to its ability to recover costs.[92]

2. <u>OPC</u>

OPC offered three witnesses: Ms. Brockway; Mr. Hornby; and Mr. Effron. Ms. Brockway challenged the assumptions underlying BGE's business case, which she contends rely on overly optimistic assumptions about participation in the Peak Time Rebate program.[93] She disputes the Company's assumption, and the studies on which it is based, that the Initiative is likely to achieve a 1% reduction in overall energy usage.[94] She argues that "the proposed Education Plan will not be successful, so long as the fundamental message of the Education Plan is compromised by the failure of BGE to demonstrate confidence in the substance of the Education Plan itself," *i.e.*, to take any risk that the Initiative will deliver benefits to customers.[95] This theme continues throughout the rest of her testimony:

> In touting the benefits of its SEP smart metering program, BGE downplays the uncertainties and negative possibilities to which I and others allude. Yet, when putting forth its position on cost recovery, BGE refuses to take any significant risks that these uncertainties and negative possibilities may occur. … That BGE refuses to take on the risks I and others describe speaks volumes about the utility's underlying view of the maturity of the technology and the ability of the technology to provide benefits to substantially all it customers.[96]

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[91] *Id.* at 30-31. Ms. Alexander did not intend for her list to be considered comprehensive, and she "acknowledge[s] that different or additional metrics might be appropriate." *Id.* at 31.
[92] *Id.* at 32.
[93] Brockway Rhg. Test. at 4-10.
[94] *Id.* at 10-15.
[95] *Id.* at 18; *see also id.* at 18-19.
[96] *Id.* at 33-35.

Mr. Hornby also argues that BGE's business case depends on overly optimistic assumptions regarding the customer participation rate and about capacity prices in PJM.[97] These two assumptions account for 75% of the supply-side benefits and are not conservative, according to his analysis of actual and future capacity clearing prices.[98] Mr. Hornby prepared an alternative business case that assumes higher costs by incorporating additional costs for in-home devices, communications, and upgrades to the Customer Information System (which includes the billing system) and lower benefits to reflect what he views as more reasonable assumptions. In his alternative business case, the Revised Proposal remains cost-effective under the Total Resource Cost test, but by a much slimmer margin than BGE's business case – before any margin of error.[99] He also concludes that residential bill impacts will be higher than BGE predicts.[100] Ultimately, he opines that BGE "has not proposed a material change in the allocation of [the risk that the project's actual benefits will not exceed its actual costs] between itself and its customers," and that we should take this risk into account in deciding whether or not to approve the project and, if so, in structuring cost recovery.[101]

Mr. Effron disputed BGE's argument that cost recovery through a regulatory asset would be harmful to the Company and to customers. At the outset, he challenged BGE's calculation of the carrying costs that a regulatory asset would accrue – by his calculation, "the total of carrying charges to be recovered would be $89 million, which is $44 million less than the $133 million calculated by the Company"[102] – and BGE agreed that

[97] Hornby Rhg. Test. at 2.
[98] *Id*. at 4-11.
[99] *Id.* at 12-14.
[100] *Id*. at 17-18.
[101] *Id*. at 21.
[102] Effron Rhg. Test. at 3-5.

Mr. Effron's method was correct.[103] From there, Mr. Effron testified that given the time value of money, customers were significantly better off with cost recovery through a regulatory asset, even with the carrying charges, rather than the Company's hybrid tracker mechanism:

> BGE does not give any recognition to the time value of money. That is, BGE assumes that a dollar paid by customers in 2010 has the same value as a dollar paid in 2025. This is contrary to all accepted principles of economics and finance. Any rational individual would rather pay a dollar fifteen years from now rather than a dollar now. A proper analysis would compare the discounted present value of the surcharge mechanism to the discounted present value of the regulatory asset mechanism to recognize the time value of money. The present value of the cost of [the] regulatory asset in relation to the present value of the cost of the surcharge depends heavily on the discount rate that is used in the analysis.
>
> <u>If the discount rate is assumed to be the pre-tax rate of return used to calculate the carrying charges, not an unreasonable assumption, then the present value of the cost of the regulatory asset to customers is significantly *less* than the present value of the surcharge to customers</u> (Exhibit DJE-1, Page 2). I have calculated that an assumed discount rate of 7.76% would leave customers indifferent between the regulatory asset and the surcharge mechanism.[104]

Accordingly, Mr. Effron opined that "[t]he Company's assertion that a regulatory asset would be more costly to customers than a surcharge mechanism is based on a spurious comparison and is no reason why the Commission should reconsider its finding that BGE may not premise its cost recovery on a surcharge mechanism but that the creation of a

[103] Tr. 1484-85 (August 5, 2010) (Case). Mr. Case testified that BGE's calculation using Mr. Effron's method yielded carrying charges of $100 million, not $89 million. *Id*.
[104] Effron Rhg. Test. at 6 (italics in original, underline added); *see also id*., Ex. DJE-1 at 2 (showing present value calculation).

regulatory asset may be acceptable."[105] He also disagreed that a regulatory asset would cause a rate spike – by his calculations, the revenue requirement for recovering a regulatory asset in the first year of recovery would be lower than the equivalent surcharge revenue requirement.[106]

At the hearing, Mr. Effron took issue with the BGE's contention that recovery through a regulatory asset would cause financial harm to the Company. He testified that a regulatory asset could be structured to include the cost of meters and depreciation and amortization expenses, that such a regulatory asset would not be unusual,[107] and that if the Company can be made whole through a tracker, it can be made whole through a regulatory asset – BGE would be at no greater risk either way.[108] And for his part, Mr. Effron would not include a return on the meters as part of any cost recovery mechanism, and he recommended that the depreciation of retired meters should be offset against the depreciation on the new meters.[109]

3. MEA

Mr. Jennings agrees with Mr. Effron: "I maintain that it would be simpler to assign the entire Smart Grid Initiative as a regulatory asset and treat the costs and benefits entirely through conventional rate case cost recovery, similar to construction of a power plant."[110] By granting a regulatory asset, Mr. Jennings says, the Commission would "send a message" that the initial decision to undertake the Initiative would not be second-guessed.[111] Although he believes that "this current Smart Grid applicatio[n] is a

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[105] *Id*. at 6-7.
[106] *Id*. at 7; *see also* Tr. 1957 (August 6, 2010).
[107] Tr. 1963-64 (August 6, 2010).
[108] Tr. 1970 (August 6, 2010).
[109] Tr. 1980-84 (August 6, 2010).
[110] Jennings Rhg. Test. at 4.
[111] Tr. 1891 (August 6, 2010).

reasonable and sound investment in light of the potential benefits if approved with certain contingencies,"[112] he views the Initiative as a partnership between BGE and its customers that requires both sides to share the risks:

> BGE, the Commission and the customers are, essentially, affecting a partnership by embarking on the Smart Grid initiative. For the partnership to be effective, I believe there are two contingencies to approving the new application. First, *the customers should not be solely responsible for the program costs if the benefits do not materialize*. *If BGE is convinced of the robustness of the TRC and the forecast of customer behavior based on the pilot programs, then during the rider true-up BGE shareholders should have some exposure consistent with the risk inherent in equity capital*. For example, as I mentioned in my earlier testimony regarding BGE's original filing, BGE should bear costs in excess of the benefits. In addition, if there are significant technological issues that require remediation, BGE shareholders may be obligated to participate in cost mitigation.[113]

Mr. Jennings also found BGE's proposed customer education plan to be a workable framework for a plan, that it "lays out a reasonable approach, reinforced by awareness that it will need to be monitored and potentially modified, while continuously incorporating emerging best practices from industry experience."[114]

At the hearing, Mr. Jennings reinforced all of these points, particularly his view that customers should not be required to bear all of the risk that the supply-side benefits (such as energy and capacity price mitigation, and monetization of the value of projected energy and capacity reductions in the PJM markets) fail to materialize. He also responded to BGE's contention that the Company would be harmed financially if we allowed cost recovery through a regulatory asset. He shared Mr. Effron's view that

[112] Jennings Rhg. Test. at 13.
[113] *Id*. (emphasis added).
[114] Jennings Rhg. Test. at 10.

regulatory assets are not harmful to consumers – they are used regularly in major transactions and in connection with power plant and major transmission line projects.[115] Although he recognized that a regulatory asset could affect the Company's cash flow in some measure, Mr. Jennings did not see how the Company would be harmed if the asset is recorded, the Company earns a return on it, and it rolls into base rates:

> But that aside, … to me in a regulatory asset, I don't understand nor agree that it is somehow punitive. The asset is recovered. It's recorded. They earn an allowed rate of return on it while it's sitting there. And at the conclusion, it rolls into base rates.
>
> And my question has been so where is the harm. If that were the case, we wouldn't be putting in power plants, not that we're putting in that many. But to that same argument, the one question is simply to cash flow and what that does to the company.[116]

He reiterated that BGE should have the responsibility to ensure (and some financial risk to deliver) appropriate communications and customer education.[117] And with regard to the legacy meters, he opined that we should allow recovery, but consider the possible duplication of recovery, and undertake that analysis in a separate depreciation proceeding.[118]

4. Staff

Commission Staff offered three witnesses: Ms. Godfrey; Mr. Hurley; and Mr. Allen. Ms. Godfrey addressed the scope of the Initiative, the technology risks, and BGE's consumer education plan. She testified that BGE's business case included the

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[115] Tr. 1894 (August 6, 2010) ("And to the extent that may or may not be – I don't particularly think that's harmful. It's an instrument that's used in most major initiatives in investment. Certainly in power plant and major transmission facilities. If it's not harmful there, I don't know why it's harmful here.").
[116] Tr. 1951-52 (August 6, 2010).
[117] Tr. 1900-03 (August 6, 2010).
[118] Tr. 1949-50 (August 6, 2010).

appropriate range of costs,[119] and that the challenges in implementing similar programs across the country have arisen more from the utilities' failure to communicate with customers than from technology failure.[120] She reiterated Staff's recommendations from the initial round that, among other things, the Commission should hire a Smart Grid evaluator to assist Staff in evaluating the implementation of the project and that BGE should be required to obtain rigorous testing guarantees from its vendors.[121] She also testified that Staff is comfortable with BGE's consumer education proposal.[122] At the hearing, she agreed with Mr. Jennings that the plan qualified as a "very robust framework," and reiterated Staff's recommendation that we convene a "work group… similar to the EmPower Maryland general awareness work group where there could be an exchange of ideas, best practices, lessons learned, et cetera, so we could continue to try and meet the participation targets that we need to meet in order to obtain the supply-side benefits."[123]

Mr. Hurley provided updated cost-effectiveness scenarios based on BGE's revised business case. His analysis concluded that the Revised Proposal is not cost-effective if it achieves no supply-side benefits,[124] but is cost-effective if it achieves two[125] or three[126] years of the projected supply-side benefits. He also analyzed various sensitivities within each of the scenarios, which demonstrated that cost-effectiveness will be a function of supply-side benefits – when customer engagement and participation diminish, cost-effectiveness is threatened, but there appears to be a comfortable margin of error below

[119] Godfrey Rhg. Test. at 3-7.
[120] *Id*. at 7-16.
[121] *Id*.
[122] *Id*. at 17-18.
[123] Tr. 2012-13 (August 6, 2010).
[124] Hurley Rhg. Test. at 5-8.
[125] *Id*. at 8-10.
[126] *Id*. at 10-12.

the Company's projections in which the Initiative still would pass mathematical cost-effectiveness tests.[127]

Mr. Allen's testimony described three basic approaches to utility cost recovery: the traditional base rate approach; establishment of a regulatory asset; and a surcharge or tracking mechanism.[128] He testified that we would grant a regulatory asset – which identifies certain costs and defers recovery of those costs to a later date, rather than recovering them on a current basis[129] – by indicating that the recovery of the included costs is probable.[130] Recognition of a regulatory asset reduces the risk of recovery compared to the risk the Company would recover other assets or costs, in his view.[131] Although Mr. Allen expressed some doubt about whether our concerns about the risks of future benefits are consistent with expressing some probability of future recovery,[132] Mr. Allen acknowledged that we have the authority to define the costs or returns any regulatory asset might include.[133] Finally, Mr. Allen opined that we should address cost recovery for BGE's legacy meters after a depreciation study, in the context of a separate depreciation proceeding, when all of the facts surrounding BGE's treatment of those meters are known.[134]

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[127] *Id*. at 8-12.
[128] Allen Rhg. Test. at 3-4.
[129] Tr. 2104 (August 6, 2010).
[130] Allen Rhg. Test. at 6; Tr. 2108 ("Q. [MS. CZARSKI] My question is does the actual standard require absolute assurance, which I take to be a hundred percent, or does the standard require probability, which might be something less than one hundred percent? A. [MR. ALLEN] Probability.").
[131] Tr. 2106 (August 6, 2010).
[132] *See*, *e.g.*, Allen Rhg. Test. at 7.
[133] Tr. 2110-11 (August 6, 2010).
[134] Tr. 2098-101 (August 6, 2010); *see also* Allen Rhg. Test. at 9 ("From a ratemaking perspective, changes to group life depreciable assets are traditionally treated in a depreciation case.").

C. BGE's Revisions to the Revised Proposal

After the last witness testified on August 6, BGE offered two amendments to the Revised Proposal (the "Amendments"). BGE proffered these revisions after gauging the Commission's reaction to the Company's Revised Proposal during the two-day hearing, and sensing that we remained concerned about the Revised Proposal's allocation of risk between the Company and customers:

> This is an amendment to our already revised Smart Grid proposal that we submitted on July the 12th, I think it was. The background of this, so the Commission's order came out in June rejecting the Smart Grid application as filed. We worked intently for a period of weeks to try to see what changes we could make to the proposal to try to address the Commission's concerns, and we were hopeful that the set of changes that we had made in our application for rehearing – we knew it wasn't one hundred percent of what we were asked, guided, directed to do in the Commission's order, but we were hopeful at the same time that it was a significant enough step that the Commission would find it in the public interest and approve the proposal.
>
> Our motivation at the time and our motivation today, wanting to do the right thing. For us the right thing is to be able to go forward with Smart Grid. We believe in it. But it was also I think fairly clear from the exchanges last night that the Commissioners, Chairman, parties to the case still have reservations about the risk that customers are facing, and BGE's so-called skin in the game, notwithstanding the fact that we're very concerned about the skin in the game. We all don't see that the same way. We recognize that.[135]

According to Mr. Case,[136] the Amendments are designed to mirror the cost recovery mechanism approved by the Corporation Commission of Oklahoma in

[135] Tr. 2133-34 (August 6, 2010) (Case).
[136] *Id*. at 2135.

connection with Oklahoma Gas and Electric Company's AMI proposal,[137] a case cited in BGE's Application[138] and discussed in Ms. Alexander's testimony.[139] Beyond those two changes, all other terms of BGE's Revised Proposal remain unchanged.[140]

First, "BGE commits to a cap of $500 million to deploy its Smart Grid system, as currently proposed."[141] This is not a hard cap on expenses: "So long as BGE implements its proposed Smart Grid system at or below this cost level, the costs shall be deemed prudently incurred. To the extent initial deployment costs exceed the $500 million level, BGE will have the burden of proof to demonstrate the prudence of such costs, and to make the case for recovery in rates."[142] This $500 million cap covers only the deployment costs (originally forecast at $482 million[143]), not post-deployment operating expenses (now forecast to be approximately $231 million[144]). And to the extent the project changed in any material way from its current form – such as, for example, if we were to require consumer education materially beyond what BGE currently has budgeted – any changes to the "scope of work" would be added to the cap.[145] The overall risk/reward equation would stay the same: BGE would "commi[t] to a working smart grid system while we're not committing to exact levels of customer demand response or conservation."[146]

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[137] *See In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Granting Pre-Approval of Deployment of Smart Grid Technology in Oklahoma and Authorization of a Recovery Rider and Regulatory Asset*, Cause No. PUD 201000029, Oklahoma Corporation Commission (May 27, 2010).
[138] Application at 10 n. 12.
[139] Alexander Rhg. Test. at 14-15.
[140] Tr. 2140 (August 6, 2010) (Case).
[141] BGE Ex. 21.
[142] *Id*.
[143] *See* Order No. 83410 at 17.
[144] These costs were originally projected to be $353 million, *see* Order No. 83410 at 17, but reducing the useful life to 10 years has reduced these expenses correspondingly. Tr. 2147-48 (August 6, 2010) (Case).
[145] Tr. 2190-91, 2194 (August 6, 2010) (Case).
[146] Tr. 2182 (August 6, 2010) (Case).

Second, "BGE commits to a minimum level of operational savings related to the elimination of meter reading expenses." As in Oklahoma (as well as California[147]), BGE would guarantee a minimum level of operational savings and discount those savings from the tracker whether or not BGE actually achieves them.[148] In this instance, "BGE commits that the operational savings currently reflected in its estimated level of savings, which are embedded in the calculation of the projected customer surcharge levels, will become a minimum or "floor" level of customers savings," a total of $90 million over the 14-year life of the project.[149] This guarantee would not alter BGE's projections regarding the bill impact of the tracker, however, since its calculations used the estimated meter reading savings during the deployment period.

The other parties reacted to the Amendments at the August 9th conference.[150] AARP and OPC renewed their opposition to the Revised Proposal, and stated that the Amendments did not change their positions.[151] Nor did the Amendments alter Staff's support for the Revised Proposal, or the conditions under which MEA supports approval.

III. Analysis

As we said in Order No. 83410, we are hopeful about the future of the "smart grid," and about the opportunities for benefits it could bring to consumers and the public at large. And although we said that "a $136 million 'discount' on an $835 million

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[147] *See* Alexander Rhg. Test. at 11 (citing Direct Testimony of Barbara Alexander at 39-40, citing California Public Utilities Commission Decision 08-09-039 (September 18, 2008), which approved Southern California Edison's AMI deployment).
[148] BGE Ex. 21.
[149] *Id.*; *see also* Tr. 2163 (August 6, 2010) (Case).
[150] Tr. 10-11.
[151] AARP noted on the record that it was not a party to the Oklahoma Gas and Electric proceeding and did not endorse the cost recovery mechanism approved there. Tr. 10-11 (August 9, 2010). AARP also moved for additional discovery and testimony if we were to consider the Amendments. We took that motion under advisement, and our ruling today renders it moot. *Id.* at 28-29.

ratepayer investment cannot dictate the outcome here,"[152] we take seriously the opportunity for federal funds to help pay down the cost of this Initiative. That is why we established such an expedited schedule for reviewing the Revised Proposal, and we are issuing this Order in time, we hope, to ensure that Maryland's opportunity for federal funding is not lost.

At the same time, we declined to approve the Initial Proposal for good reasons that we considered carefully. Order No. 83410 not only represents the law of this case, but articulated the principles against which we measure AMI and "smart grid" infrastructure proposals in Maryland. We grounded Order No. 83410 first and foremost in the governing law, which requires us to find that any such program is cost-effective,[153] in established regulatory principles governing the construction of utility infrastructure, and from the perspective that "[w]e simply think it more equitable that BGE and its ratepayers venture into this relatively unknown territory as partners."[154]

Rather than reinventing the AMI wheel, then, we examine the Revised Proposal against the standards and principles set forth in Order No. 83410. The primary questions before us here are "what has changed from the Initial Proposal?" and "do those changes resolve the concerns that prevented us from approving that Proposal?"

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[152] Order No. 83410 at 4.

[153] *See* Order No. 83410 at 26-27 (citing PUC §§ 7-211(f) and (i)). We have explained elsewhere that "'[t]he Commission views cost-effectiveness as requiring a real rate of return on ratepayers' investment, measured by meaningful bill savings for all ratepayers,' and we do not view the outcomes of the TRC or other California Manual tests as dispositive or binding. … The mere fact that an EE&C program might pass certain commonly-utilized tests does not, in itself, compel us to commit millions of dollars to such programs. Accordingly, the analysis of cost-effectiveness will be informed by the impact of these programs on ratepayers' utility rates and bills, as well as the allocation of costs and the achievement of energy savings, but at the end of the day we must be persuaded that the individual and collective benefits are worth the ratepayers' investment." *In the Matter of Baltimore Gas and Electric Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPower Maryland Energy Efficiency Act of 2008*, Order No. 82384, Case No. 9154 (December 31, 2008) (quoting Commission Letter Order to BGE, Item No. 10, June 18, 2009 Administrative Meeting, Maillog No. 108061 (August 18, 2008)).

[154] *Id*. at 54.

For the reasons that follow, we approve the Revised Proposal with conditions that reflect the appropriate form of cost recovery and that provide for ongoing reviews, by us, to gauge the progress of the project. Those reviews would use specific metrics, which we generally will describe here and direct the parties to develop, designed to measure the progress of the project and the benefits to ratepayers. We recognize that issues remain to be addressed, including critical privacy and cyber-security concerns, and that we and the parties will need to work through them together carefully. We are comfortable, however, that the public interest is served by a decision to move forward with this Initiative under the conditions set forth below.

A. Cost Recovery

In Order No. 83410, we held that "we will not authorize cost recovery for any approved 'smart grid' or AMI project through a surcharge."[155] We reached that conclusion because the proposed AMI deployment "would represent a large, but classic, investment in BGE's distribution infrastructure," precisely the kind of investment that BGE has recovered through traditional ratemaking for a century.[156] We were not persuaded to deviate from these principles by BGE's arguments regarding the magnitude of the AMI investment or the possibility of negative reactions from credit rating agencies.[157] We also noted that "unlike a regulatory asset, the requested surcharge requires ratepayers to bear the costs of this substantial investment immediately, despite BGE's expectations that they will receive no benefit at all until 2012, at the earliest, and that some BGE customers will not be eligible to fully realize the anticipated benefits of

[155] Order No. 83410 at 30.
[156] *Id*. at 28-30.
[157] *Id*. at 30.

the Proposal until full AMI deployment is completed in or around 2014."[158] We concluded, therefore, that "[i]f BGE intends to pursue a modified AMI proposal consistent with the parameters set forth in this Order, BGE may not premise its cost recovery on a surcharge mechanism."[159]

In the Revised Proposal, as revised further on August 6, BGE asks us to reconsider these decisions. The Revised Proposal modified the duration of the tracker and altered other features of BGE's original cost recovery proposal,[160] but BGE remains firm in requiring surcharge recovery beginning at the outset of the program or close thereto (January 1, 2011).[161] BGE responds with some of the same arguments it made before. Although BGE agrees the Initiative involves "classic utility infrastructure," it distinguishes this project based on its size and pace of the buildout.[162] BGE repeats its earlier arguments about the more "credit supportive" nature of a tracker,[163] and cites 11 other utility commissions that have approved some form of a tracker for recovery of at least some portion of the costs related to their utilities' AMI programs.[164] In addition, BGE argues now that a regulatory asset would be bad for *customers* because a regulatory asset would accrue carrying charges, because a regulatory asset could cause a rate spike when recovery begins, and because the risks to the Company's credit metrics make every other BGE investment more expensive for ratepayers.[165]

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[158] *Id*. (footnotes omitted).
[159] *Id*. at 31.
[160] Application at 7-10; Case Rhg. Test. at 3-9.
[161] Application at 7, 26; Case Rhg. Test. at 6-9; Tr. 1495-96 (August 5, 2010) (Case); *id*. at 1762 (August 5, 2010) (Case).
[162] Application at 9; Case Rhg. Test. at 5, 8-9.
[163] Application at 9; Case Rhg. Test. at 7.
[164] Application at 10 n. 12; Case Rhg. Test. at 6 and n.1.
[165] Case Rhg. Test. at 7; *see also* Application at 7-10.

BGE's presentation at this stage also augmented its description of the risks it fears, both for itself and on behalf of its investors. At one level, BGE fears that the structure of any regulatory asset poses a risk that BGE would achieve less than a full recovery and, compared to a tracker, could harm the Company's cash flow:

> An important distinction for not establishing Smart Grid as a regulatory asset is that it would represent an inappropriate application for a set of assets that are in service, used and useful, where costs are being depreciated and amortized. This is not the typical application for use of the regulatory asset. … Absent specific provisions for a regulatory asset, investors would also experience significant earnings attrition in addition to the adverse impacts on cash flow and credit metrics. Among others, these provisions include a requirement to add depreciation and amortization expenses into the balance of the regulatory asset, and to provide a return on assets that are in service. BGE estimates an earnings loss of about $60 million absent those specific and unusual provisions of a regulatory asset. Additionally, it places unacceptable risks on investors that would be required to invest several hundred million dollars and be subject to waiting several years before learning whether a future Commission will agree that BGE invested such sums wisely. These concerns and adverse impacts are in addition to the previously described harms to customers under a regulatory asset approach, and are intended to clarify why BGE could not move forward under such an approach and why it is not best for customers.[166]

Upon further examination, though, BGE's perception of risk appears to flow in some part from a fundamental mistrust of the regulatory process in this State, from a sense that BGE is not treated fairly by this Commission or in the Maryland regulatory environment.[167] We will not say more on this latter point other than to disagree, respectfully. This Commission consistently has treated BGE or its parent fairly and according to the same standards that apply to any other public service company. We will,

[166] Case Rhg. Test. at 8-9; *see also* Tr. 1523-26 and 1609-10 (August 5, 2010) (Case).
[167] Tr. 1629-32 (August 5, 2010) (Case).

however, address BGE's concerns about cost recovery under the regulatory asset approach that we still find to be the best, and most appropriate, methodology for this Initiative.

We find that a regulatory asset, recovered through base rate cases, provides the Company with an opportunity for recovery of prudently incurred costs, while synchronizing the cost to customers most closely with the onset of benefits. As a matter of principle, regulatory asset treatment is consistent with our decision in Order No. 83410, and we adhere generally to that holding here. Along with the reasoning we adopted in June, we agree with MEA's witness, Mr. Jennings, that AMI deployment is analogous to an investment in a power plant,[168] an investment of similar (or greater) magnitude that historically would be recovered through traditional ratemaking.[169] Given the strength of MEA's support for smart grid generally,[170] we find Mr. Jennings's argument powerful here. And although AARP and OPC generally oppose the Initiative, Ms. Alexander[171] and Mr. Effron[172] also urge us to condition any approval on cost recovery through traditional ratemaking principles. We are bolstered as well by the fact

[168] *See* Jennings Rhg. Test. at 4 ("Despite BGE's arguments that a regulatory asset treatment of Smart Grid costs can be harmful to customers, I maintain that it would be simpler to assign the entire Smart Grid Initiative as a regulatory asset and treat the costs and benefits entirely through conventional rate case cost recovery, *similar to the construction of a power plant*.") (emphasis added).
[169] *See also* Tr. 1721-22 ("CHAIRMAN NAZARIAN: When BGE built power plants in the old days, they did not get trackers to start recovering the cost, correct? MR. CASE: I think that is correct. They accrued AFUDC. CHAIRMAN NAZARIAN: And if the company sunk a bunch of money into a power plant and the power plant never delivered any electricity or delivered considerably less electricity than it was supposed to, the company's recover[y] for the cost of that power plant would be in some doubt, wouldn't it? MR. CASE: I suppose it probably would.").
[170] *See* Jennings Rhg. Test. at 12-13; *see also* Letter from M. Woolf to D. Nazarian, July 14, 2010, Item No. 64.
[171] Alexander Rhg. Test. at 18 ("However, should the Commission seek to set forth an alternative cost recovery method, I recommend that BGE be required to seek cost recovery in a future base rate case in which it must document that the estimated benefits have in fact occurred and some portion of its cost recovery is required to be at risk for its failure to deliver the estimated benefits, both for distribution and generation supply benefits.").
[172] *See* Effron Rhg. Test. at 2-8.

that we are not alone, or even outliers, in this view: according to BGE's testimony, the majority of utilities nationally that are rolling out AMI projects – 15 out of 26 – are recovering their costs without a tracker.[173] As Ms. Alexander explained, our counterparts in Delaware deferred *any* consideration of cost recovery for DPL's AMI deployment to a future base rate case beyond recognition of a regulatory asset, and they left themselves "free to challenge the level or any other aspects of the [regulatory] asset's recovery in rates when Delmarva seeks recovery of the regulatory asset in base rates."[174] And indeed, here in Maryland, DPL and Potomac Electric Power Company are seeking cost recovery for their proposed AMI programs through a regulatory asset, not through a tracker.[175]

Nevertheless, we have not hewn reflexively to our earlier decision. We have considered BGE's new arguments and more fully articulated concerns with great care, the tight schedule notwithstanding. There are two key reasons why the Company's new arguments against regulatory asset treatment, and in favor of a tracker, have not persuaded us to depart from our decision in Order No. 83410.

First, the record in this case demonstrates that we can readily construct a regulatory asset that affords BGE an opportunity for recovery of its prudently incurred costs and a return on its investment. Messrs. Effron,[176] Jennings[177] and Allen[178] all

[173] *See* Application at 10 and n.12 and Case Rhg. Test. at 6 and n.1.
[174] Alexander Rhg. Test. at 12 (quoting Order No. 7420, September 16, 2008, PSC Docket No. 07-28 and PSC Regulation Docket No. 59 (Delaware Public Service Commission), at 5-6).
[175] *See, e.g.*, Request for Expedited Approval to Establish a Regulatory Asset for the Deployment of AMI, In the Matter of Potomac Electric Power Company and Delmarva Power and Light Company Request for the Deployment of Advanced Meter Infrastructure, Case No. 9207, Item No. 1 (March 26, 2009); *see also* Effron Rhg. Test. at 5 (by structuring a regulatory asset as he recommends, "these modifications would do nothing more than align the BGE recovery mechanism with that proposed by the PHI companies.")..
[176] Effron Rhg. Test. at 6-7; Tr. 1957, 1963-64, 1970 (August 6, 2010) (Effron).
[177] Jennings Rhg. Test. at 4, 10, 13; Tr. 1891, 1894, 1900-03, 1949-50 (August 6, 2010) (Jennings).
[178] Allen Rhg. Test. at 6-7; Tr. 2104, 2106, 2110-11 (August 6, 2010) (Allen).

refuted BGE's claims that "unless the regulatory asset were structured in I think a very unusual way, the company would not be able to recover its costs, would not be able to earn its authorized return."[179] To the contrary, the Company should be no worse off either way.[180]

Second, we are persuaded that customers will be better off with a regulatory asset than a tracker, even a tracker containing the limiting features BGE proposed on August 6.[181] A key benefit of a regulatory asset is that it matches customer costs and benefits more closely than a tracker can. By providing the opportunity for ongoing rate case review of BGE's costs and recovery, a regulatory asset also mitigates (and potentially allocates between BGE and its customers) the risks of this project. Although BGE is correct that recovery through a regulatory asset will cause customers to incur carrying costs,[182] Mr. Effron's analysis demonstrates that customers are still ahead money on a present value basis.[183] Mr. Effron also demonstrated that the revenue requirement for recovering a regulatory asset in rates would be a million dollars lower than the cost of the surcharge.[184] And although BGE's analysis of customer bill impact suggests that customers would save money each month under the tracker mechanism,[185] those savings will be illusory for a large number of customers: most of the savings during the deployment years take the form of a reduction in the PeakRewards surcharge, which will

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[179] Tr. 1609-10 (August 5, 2010) (Case).
[180] Tr. 1970 (August 5, 2010) (Effron) ("MR. EFFRON: I'm not in a good position to say what they should prefer or shouldn't prefer. I should leave that to them. From an earnings perspective there's no difference. They're made whole through a tracker mechanism, then they can be made similarly whole through a regulatory asset mechanism. They're not being deprived of anything through a regulatory asset mechanism to any extent greater than they would or wouldn't be through a tracker mechanism.").
[181] *See* BGE Ex. 21.
[182] *See* Case Rhg. Test. at 7. Mr. Effron's analysis identified a calculation error that reduced the projected carrying costs considerably. *See* Effron Rhg. Test. at 3-5.
[183] *See* Effron Rhg. Test. at 6 and Ex. DJE-1 at 2.
[184] *See* Effron Rhg. Test. at 7; *see also* Tr. 1957 (August 6, 2010) (Effron).
[185] *See* BGE Ex. 20.

flow (by virtue of the federal funds) to customers regardless of our cost recovery decision here.[186] The bulk of the remaining savings (which do not begin in earnest until 2013) come from Peak Time Rebates, which will only be available to customers who have their new "smart" meters installed.[187] The only direct savings that customers would forego during the deployment years if we do not approve a tracker are the $15 million in reduced meter reading costs that BGE would pass through (and, in its August 6 Amendments, would guarantee).[188] While having to wait to realize these savings is less than ideal, overall we believe the customer is better off for not having had to pay $160 million in surcharges in advance to achieve those savings.

As we balance the interests of the Company with those of its customers in this context, we think it important to note the following:

- We recognize that BGE should recover the prudently incurred costs it incurs in connection with this Initiative, as well as an appropriate return. Accordingly, we recognize that the regulatory asset we authorize here may include the incremental costs to implement the Initiative, as well as the net depreciation and amortization costs relating to those meters, and an appropriate return for those costs;
- We recognize that BGE's ultimate obligation is to deliver a cost-effective AMI system, including the necessary communication and customer education. We find it

[186] Tr. 1730-31 (August 5, 2010) (Case).
[187] Tr. 1731 (August 5, 2010) (Case) (projecting that 60% of customers will have a new meter by the summer of 2013).
[188] Tr. 2163 (August 6, 2010) (Case).

reasonable to expect that BGE will deliver a cost-effective AMI system before cost recovery will be incorporated into rates, and the Company's customers should not be required to pay in full, with a return, if the system does not meet that essential standard. We recognize that there is inherent uncertainty that the level of benefits projected, particularly the supply-side benefits, will actually be realized. If the final system falls short of being cost effective, we will hold a fair and appropriate proceeding to determine what cost recovery outcome the public interest requires; and

- Our recognition of a regulatory asset is not an advance determination that all costs related to the Initiative are prudent. We recognize that "prudent" does not mean "clairvoyant" or "perfect," and that a proper prudency review should not subject the Company to an unfair, *post hoc* nickeling-and-diming. But we also will not deem any costs as "prudent" in advance – the appropriate time to determine prudence is when recovery of the regulatory asset is sought.

We find this outcome reasonable and consistent with the public interest. If, as BGE claims, its estimates of customer benefits are conservative,[189] BGE should have no trouble demonstrating its right to full recovery in rates once the AMI system is built. With a tracker, it would be nearly impossible to unring the bell. Money would flow from customers to the Company before significant benefits, and BGE's well-intentioned review proposal would put us to the impracticable challenge[190] – one that has proven daunting in the EmPower Maryland context – of monitoring this project in real time and making on-the-fly decisions (that, in BGE's view, would be binding for cost recovery purposes) about how and on what terms to proceed. If things were to go wrong, we would find ourselves in a position of having to consider ordering BGE to issue credits to customers.

BGE contends that cost recovery without a tracker will delay the Company's cash flow and adversely affect BGE's credit metrics,[191] but there is no concrete evidence in the record to back up these claims. And BGE will, if it chooses to proceed with a regulatory asset, receive $136 million in federal matching funds for AMI during that same timeframe. We see no basis in this record to find that BGE lacks the financial wherewithal to carry out the Initiative with cost recovery through a regulatory asset as described herein.

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[189] *See, e.g.*, Case Rhg. Test. at 13 ("We also developed our business case in what we considered to be an extremely conservative fashion, assuming a lower level of savings than the results we saw in the 2008 pilot, and excluding completely many forms of savings we anticipate to result from Smart Grid. … The reason we deliberately developed such a conservative business case was so that the Commission and other stakeholders could feel confident in the likelihood of at least achieving, and very probably exceeding, the projected level of savings."); *id*. at 23 ("However, BGE's business case is highly conservative, and the benefits are likely to be higher than projected."). OPC's witnesses, Ms. Brockway and Mr. Hornby, challenged the Company's characterization of the business case as conservative. *See* pp. 20-21 above.
[190] *See* Brockway Rhg. Test. at 22-24 ("A regulatory commission cannot be expected to identify the needle of a possibly imprudent decision in the haystack of management decisions made during the implementation of the project.").
[191] Case Rhg. Test. at 7.

Finally, we cannot prejudge the precise cost recovery for BGE's legacy meters at this time. The complicated issues relating to legacy meter recovery are appropriately aired in a depreciation proceeding, with the benefit of a depreciation study and a proper factual record, including actual removal, disposal and salvage of the legacy meters.

B. Time of Use Rates

In Order No. 83410, we held that although "we support encouraging customers to shift to peak-time energy use whenever possible," we were unwilling to approve an AMI proposal that included mandatory Time of Use rates.[192] We grounded this holding primarily in two concerns: (1) requiring all customers to move to TOU rates could disadvantage low-income customers, elderly customers, customers with medical-related energy needs, and others who may have difficulty shifting their usage to off-peak times;[193] and (2) BGE had not provided a comprehensive analysis that allowed us to determine whether its business case remained cost-effective without mandatory TOU rates.[194] We invited BGE in any revised proposal to analyze its business case without mandatory TOU pricing and to propose Peak Time Rebates for all BGE customers, even those who stay on Standard Offer Service.[195]

BGE's Revised Proposal addressed these concerns directly. Putting aside the question of whether we misunderstood the terms of the Initial Proposal, the Revised Proposal unambiguously withdrew the requirement that all customers move to a TOU rate structure and clarified that BGE's business case does not rely on any customer

[192] Order No. 83410 at 31-35.
[193] *Id*. at 31.
[194] *Id*. at 32. As we discuss below, mandatory TOU rates also raised concerns regarding the absence of a customer education plan. *Id*. at 33.
[195] *Id*. at 33-34.

benefits resulting from mandatory TOU rates.[196] None of the other parties took issue with this revision, and we appreciate BGE's response.

C. Consumer Education

In the course of articulating our concerns about mandatory TOU pricing, we also noted in Order No. 83410 that "[b]ecause we believe the success of any TOU rate schedule will depend heavily on a significant investment of time and resources in consumer education prior to implementation, we expect the Company to provide, in any future proposal involving TOU pricing, a detailed education plan that will prepare its ratepayers for the coming changes."[197] In response, BGE attached a 66-page "Smart Grid Consumer Education and Communication Plan" to its Application.[198] The Company recognizes that the plan in its present form represents a starting point, a framework for further discussions with the other parties and something on which the Company will build as the Initiative evolves.[199] BGE has budgeted $66 million for communications and consumer education over the fourteen-year life of the Initiative,[200] approximately $31 million of which will be spent during the initial deployment period.[201] This total includes not just consumer education but also the cost of notifying customers of impending Peak Time Rebate opportunities as well as the development of the web portal.[202]

We find, and all of the parties appear to agree, that effective customer education will be critical to the acceptance and success of the Initiative. The negative experiences in other states, especially California and Texas, illustrate vividly that poor customer

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[196] *See* pp. 10-11 above.
[197] Order No. 83410 at 33.
[198] Application at 20 and Attachment 2.
[199] *See* p. 11 above.
[200] Tr. 1621-23 (August 5, 2010) (Case); BGE Ex. 19.
[201] Tr. 2193 (August 6, 2010) (Case).
[202] BGE Ex. 19.

education will magnify small-scale problems and create disproportionate customer skepticism and unhappiness.[203] We and the parties are of varying minds on the suitability and readiness of the plan – throughout the hearing, we,[204] AARP[205] and OPC[206] questioned aspects of its contents and focus. We also have expressed concerns about whether the budget for customer education is adequate, and whether the Company's approach to budgeting, and its effort to manage deployment costs, might squeeze spending on customer education if other costs run over.[207] But everyone, including those who are more comfortable with the plan,[208] seems to recognize that the plan will need further vetting, input and modification.

The fact that this is an undisputed work in progress does not stand in the way of our decision to approve this Initiative at this time, and we are prepared to allow BGE to start down the path that its plan charts. But we cannot emphasize this strongly enough: *the success of this Initiative, and the likelihood that customers will actually see the benefits this project promises, depend centrally on the success of the Company's customer education and communication effort*. It is not enough just to have a plan – the Company *must* devote the necessary time and resources to this aspect of the Initiative, education and communication must be ready to go *before* each stage of the deployment, and the Company cannot artificially limit the funds and resources available to education and communication by sticking rigidly to predetermined budgets or by diverting resources from education to other tasks. Timing is crucial – customers must get the

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[203] *See* Alexander Rhg. Test. at 15-16, 29; Godfrey Rhg. Test. at 8-10.
[204] *See, e.g.*, Tr. 1712-18 (August 5, 2010) (Commissioner Williams's examination of Mr. Case); Tr. 2026-30 (August 6, 2010) (Commissioner Williams's examination of Ms. Godfrey).
[205] Alexander Rhg. Test. at 29-32.
[206] Brockway Rhg. Test. at 15-19.
[207] Tr. 2189-92 (August 6, 2010) (Case).
[208] Godfrey Rhg. Test. at 17-18.

information they need *before* BGE installs meters in houses, *before* Peak Time Rebates begin, and *before* any other programmatic changes would take effect.

We also find that BGE's performance in this regard should be measured against specific customer education and communications metrics. Accordingly, we direct the parties to develop a comprehensive set of metrics and submit them for our approval before implementing any consumer education and communications plans. Ms. Alexander's preliminary list of metrics is a good starting point,[209] particularly as they seek to measure customer understanding at different stages of the project, but that list should not be treated as complete or exhaustive.

D. Risk Mitigation and Allocation

Finally, our prior decision not to approve the Initial Proposal turned in large measure on our concern that BGE's customers would, as that Proposal was structured, bear all of the risks inherent in the project.[210] These risks take at least two different forms: technological risks, *i.e.*, the risk that the technology underlying the Initiative might not work as planned; and financial risks, *i.e.*, the risk that the assumptions underlying the business case about projected costs and benefits, both operational and supply-side, do not hold true. In the course of analyzing the Initial Proposal, we found that it allocated *all* of the technological and financial risks to BGE's customers. Had we approved the Initial Proposal, BGE would have been bound to build a functioning AMI system, but would still have been entitled to full cost recovery, and a full rate of return, whether or not customers received any of the projected benefits. BGE disputes that the Initial Proposal guaranteed cost recovery, and argues that the Company would have been

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[209] Alexander Rhg. Test. at 30-31.
[210] Order No. 83410 at 35-53.

subject to ongoing prudence reviews that could have resulted in disallowances.[211] But without knotting ourselves up on the word "guarantee," the Initial Proposal was designed to maximize the certainty and timeliness of cost recovery for the Company and its shareholders, and it was clear that the Company did not expect to be accountable to this Commission or its customers to deliver anything beyond a system of new meters that communicated data to the Company's computer systems. The outcome obviously would matter deeply to the Company for other reasons, but the Initial Proposal preserved, first and foremost, the Company's return on investment.

We say this not as a criticism – the Company is entitled, and indeed is obliged, to look out for its interests and those of its shareholders, and is not charged, as we are, with divining the public interest – but to explain again why we could not approve the Initial Proposal. And the same dynamic runs throughout the testimony, written and oral, submitted in this stage of the case. BGE expresses genuine enthusiasm throughout for the opportunities the "smart grid" offers for the Company and its customers,[212] but continues to argue that the Company should not be expected to bear any of the risk that the costs to customers might fail to yield benefits.[213]

Mr. Case listed 15 different ways through which, BGE argues, it is "mitigating risks for BGE customers,"[214] and the Company's August 6 amendments to the Revised Proposal add two more steps.[215] We appreciate and do not minimize the significance of any of these steps. But BGE concedes, as it must, that the Company's responses are designed primarily to *mitigate* the risks to customers, not to *allocate* them between the

[211] Application at 5-6.
[212] *See, e.g.*, Tr. 2133-34 (August 6, 2010) (Case).
[213] *See, e.g.*, Tr. 1605-07 (August 5, 2010) (Case).
[214] Tr. 1487-92 (August 5, 2010) (Case).
[215] BGE Ex. 21.

Company and its customers.[216] And in that regard, the Revised Proposal, even as amended, does not quite succeed in responding to Order No. 83410.

As a matter of technological risk, the Revised Proposal is the same as the Initial Proposal. BGE reminds us of the pilots it conducted in 2008 and 2009, and adds in its testimony updated information about the status of AMI and "smart grid" deployments around the country and around the world.[217] But upon approval of the Revised Proposal, BGE will install the same meters, communications networks, meter data management systems and everything else it would have installed had we approved the Initial Proposal.

With regard to financial risks, BGE has revised its business case in response to many of our concerns.[218] BGE's analysis suggests that the Initiative will pass cost-effectiveness muster, at least from a TRC standpoint, under BGE's assumptions of customer benefits, and even if one were to include costs, such as legacy meters, a new billing system, in-home displays or additional consumer education, that the Company would not include.[219] Staff agrees – Mr. Hurley's analysis reveals that the project becomes cost-effective after two years of projected supply-side benefits, and is cost-effective even under pessimistic assumptions about customer participation and price mitigation.[220] OPC is less optimistic, but even its analysis reveals that the project could ultimately be cost-effective, albeit with less margin of error.[221] Everyone agrees, however, that the hard, operational benefits alone do not yield benefits commensurate with the costs of the Revised Proposal: by BGE's own reckoning, the operational

[216] Tr. 1589 (August 5, 2010) (Case).
[217] Application at 12-13; Case Rhg. Test. at 15-21; *see also* pp. 12-16 above.
[218] Case Rhg. Test. at 23-28.
[219] *Id*.
[220] Hurley Rhg. Test. at 5-12.
[221] Hornby Rhg. Test. at 12-14.

benefits cover only 75% of the project's costs,[222] and thus the project is not cost-effective on that basis alone.[223] We are more confident that customers will in fact receive benefits from Peak Time Rebates[224] than from mandatory TOU pricing, although there may, with further study and appropriate customer education, be a role for TOU prices in the future. But one way or another, customers must achieve some level of supply-side benefits – perhaps only a fraction of what BGE projects – or *they* risk paying in full for something they have not received.

Whereas BGE appropriately seeks to protect BGE's interests, it is our role to ensure that this Initiative, upon approval, is consistent with the *public* interest. Although we acknowledge that nothing is risk free, we find that the Revised Proposal, as amended, would improve on the Initial Proposal with regard to *mitigating* technological and financial risks to customers, but the Revised Proposal still *allocates* almost all of the risk to them. And without an appropriate, if modest, allocation of the risks this project presents, we cannot approve it.

Our resolution of the cost allocation question largely resolves this problem, both as to technological and financial risks. By directing cost recovery through a properly structured regulatory asset, recovered in base rate cases, we find that customers are appropriately protected against the possibility that they will pay in full for an AMI system that would not be cost-effective. Moreover, we find some additional comfort in the fact that the record now contains some additional evidence, from deployments in other states,

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[222] *See, e.g.*, Tr. 1743 (August 5, 2010) (Case).
[223] *See, e.g.*, *id*; *see also* Hurley Rhg. Test. at 5-6.
[224] We are comfortable with the Company's proposal to pay and collect revenue for Peak Time Rebates through a separate rider. Tr. 1566-67 (August 5, 2010) (Case). BGE also confirmed that Peak Time Rebates will be available to all customers, including those who purchase supply from third parties. Tr. 1687 (August 5, 2010) (Case).

to supply lessons on how not to deploy AMI and how not to (mis)communicate with customers.[225] We know that there have been hiccups and stutter-steps in these implementations, but we in Maryland have the opportunity to learn from the mistakes elsewhere and avoid them here.

We also can, and will mitigate both the technological and financial risks further by requiring BGE to measure its performance with regard to deployment and customer benefits and reviewing the status of the Initiative regularly. These reviews will monitor the progress of the Initiative against concrete metrics – the results may well inform our analyses of prudence and cost-effectiveness in the rate cases to follow, and thus our future cost-recovery decisions, but the reviews themselves will focus primarily on whether the Initiative is being deployed properly and on schedule, whether and how it functions, whether and to what extent customers are receiving benefits, and how the costs compare to the Company's budget. Put another way, we want to know where we are, where we are going, and what BGE will need to do in order to get there. In addition to the customer education and communications metrics ordered above, which will be included in the reviews as well, these metrics should distinguish operational and supply-side benefits, demarcate demand response enabled by PeakRewards versus AMI, and differentiate among gas and electric customers and among all customer classes. Accordingly, we direct BGE and the parties to develop, and submit for our approval, a comprehensive set of installation, performance, benefits and budgetary metrics that will allow us and the public to gain a full understanding of whether, and to what extent, this Initiative is being deployed and is working as planned.

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[225] *See* Alexander Rhg. Test. at 15-16, 29; Godfrey Rhg. Test. at 8-10.

IV. Conclusion

We concluded Order No. 83410 by saying that "we believe whole-heartedly in the intentions behind BGE's Proposal," and that "nothing in [that] Order should be construed as a vote of 'no-confidence' in smart-grid technology's ability ultimately to lower energy bills, improve customer service and relieve peak-time pressure on the transmission and distribution infrastructure."[226] We meant it then, and we still mean it now. With the conditions set forth above, we now authorize BGE to build it. Last time, given BGE's insistence on certain terms we found inconsistent with the public interest, we said "no." This time, based on those same principles, we are willing to say "yes, with appropriate conditions," and to define what those conditions are.

By pulling this trigger, we recognize that we are authorizing BGE to start down this path, and that we cannot later second-guess the threshold decision to allow the Company to proceed. If the project goes as BGE predicts, or anything like it, BGE should have no trouble proving in its future distribution rate cases that it has delivered the benefits to consumers that make the project cost-effective and, therefore, bring it into compliance with Public Utility Companies Article § 7-211.[227] As with any major infrastructure investment, however, BGE's customers deserve appropriate protection against bearing all of the project's technological and financial risks.

IT IS THEREFORE, this 13th day of August, in the year Two Thousand and Ten by the Public Service Commission of Maryland,

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[226] Order No. 83410 at 53.
[227] Order No. 83410 at 26-27.

ORDERED: (1) That the Baltimore Gas and Electric Company is authorized to deploy an AMI Initiative consistent with its Proposal, as amended by its July 12, 2010 filing, and as further conditioned by this Order;

(2) That Baltimore Gas and Electric Company is authorized to establish a regulatory asset for the AMI Initiative that may include the incremental costs to implement the AMI Initiative, as well as the net depreciation and amortization costs relating to the meters, and an appropriate return for those costs, and at the time that the Company has delivered a cost-effective AMI system, the Company may seek cost recovery into base rates;

(3) That cost recovery for the legacy meters that Baltimore Gas and Electric Company will remove to replace with "smart" meters shall be considered in a future depreciation proceeding;

(4) That Baltimore Gas and Electric Company shall submit, for the Commission's approval, the Company's updated customer education plan and associated proposed messaging that it will provide customers prior to and during installation of the meters, before Peak Time Rebates begin, and before any other programmatic changes take effect. Baltimore Gas and Electric and the other parties in the matter shall develop, and submit for Commission approval, a comprehensive set of metrics by which the Commission may measure the effectiveness of the customer education plan, as implemented, during periodic reviews of the Initiative and in base rate proceedings;

(5) That Baltimore Gas and Electric Company and the other parties shall work together to develop, and submit for the Commission's approval, a comprehensive set of installation, performance, benefits and budgetary metrics that will allow the Commission to assess the progress and performance of the Initiative, including a format for reporting such metrics to the Commission on a periodic schedule, to be determined at a later time;

(6) That Baltimore Gas and Electric Company shall notify the Commission whether the Company will proceed with the Initiative. Upon notification that the Company intends to proceed, the Commission shall order a status conference; and

(7) That all motions not granted herein are denied.

/s/ Douglas R.M. Nazarian

/s/ Harold D. Williams

/s/ Susanne Brogan

/s/ Lawrence Brenner

/s/ Therese M. Goldsmith